Decision 14-12-082 December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company in its 2012 Nuclear Decommissioning Cost Triennial Proceeding.	Application 12-12-012 (Filed December 21, 2012)
Joint Application of Southern California Edison Company and San Diego Gas & Electric Company for the 2012 Nuclear Decommissioning Cost Triennial Proceeding to Set Contribution Levels for the Companies' Nuclear Decommissioning Trust Funds and Address Other Related Decommissioning Issues.	Application 12-12-013 (Filed December 21, 2012)

FINAL DECISION ON PHASE 2 OF THE TRIENNIAL REVIEW OF NUCLEAR DECOMMISSIONING TRUSTS AND RELATED DECOMMISSIONING ACTIVITIES FOR SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, AND PACIFIC GAS AND ELECTRIC COMPANY

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Summary

On December 21, 2012, Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) filed a Joint Application, and Pacific Gas and Electric Company (PG&E) (collectively the "Utilities") filed its Application, for the 2012 Nuclear Decommissioning Cost Triennial Proceedings (NDCTP).[1] SCE and SDG&E own approximately 78% and 20% interests, respectively, in San Onofre Nuclear Generating Station (SONGS).[2] PG&E owns the Diablo Canyon Nuclear power plants (DCPP) Units 1 and 2, and the Humboldt Bay Power Plant Unit 3 (HBPP3). SCE owns a 15.8% interest in Palo Verde Nuclear Generating Station Units 1, 2, and 3 located in Arizona.

The proceedings were consolidated and reviewed in two phases. Phase 1 provided the reasonableness review of the identified past & future decommissioning costs at Humboldt Bay Power Plant. The remainder of the issues in these proceedings, including rate of return on all nuclear decommissioning Trust Funds and calculation of revenue requirements, were

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[1] In Decision (D.)95-07-055, in the Commission's OII 86 Re Present and Alternative Methods of Financing Nuclear Facility Decommissioning Costs, the Commission ordered all electric Utilities that own nuclear generating facilities to update their "engineering cost studies and ratepayer contribution analysis" for nuclear decommissioning costs every three years. (D.95-07-055, Ordering Paragraph 7, at 30.)

[2] The City of Riverside holds the remaining ownership interest.

assigned to Phase 2 with a delayed schedule. This decision resolves all issues remaining in these consolidated proceedings.

The primary purposes of the NDCTPs are to approve updated reasonable cost estimates for decommissioning nuclear plants in order to establish the annual revenue requirements for the decommissioning trust funds for each nuclear power plant. These trust funds were created to ensure sufficient funds will be available to complete decommissioning of all nuclear plants. Thus, this decision both establishes reasonable cost estimates and, based on assumptions regarding the expected rates of return on the existing trust funds, adopts the calculated necessary contributions to maintain funding assurance.

The high level cost estimates developed prior to commencement of actual decommissioning activities are not a set of assumptions or approaches that compel the utilities to conduct decommissioning activities in a particular way.

Additionally, because SONGS Units 2 and 3 were prematurely closed in 2013, the Commission and ratepayer groups focused on ensuring that decommissioning funds are only used for reasonable and prudent activities. The Commission herein adopts a mechanism to establish a more transparent and accountable format for cost disclosure by SCE when estimating and undertaking decommissioning activities for SONGS 2 and 3. The reorganized costs by project, for example, are expected to improve the clarity of SCE's decommissioning plans, costs, and schedules, thus providing better understanding of the financial impacts of decommissioning problems as they arise. Both SCE and SDG&E agreed in principle with ratepayer groups who sought reporting changes to improve decommissioning cost disclosure.

In this decision, we approve decommissioning cost estimates for SONGS Units 1, 2 and 3. SONGS 1 permanently ceased operations in 1992 and the approved estimate to complete decommissioning is $182.3 million (100% 2011$). We also approved SCE's estimated total costs of $4.132 billion (100% 2011$) for decommissioning SONGS 2 and 3 under an Early Decommissioning scenario which assumes shutdown in 2013. SCE did not meet its burden of proof as to $13.9 million it claims to have spent on SONGS 1 decommissioning activities in 2011 and 2012.

In addition, we found reasonable SCE's estimated share of the costs, based on its minority ownership interest, in Palo Verde Nuclear Generating Station. The adopted estimate of $513.5 million reflects SCE's adjustments to reflect omitted activities in the initial estimate and to replace a range of contingency factors with 25% for all activities.

Based on adopted assumptions regarding the expected rates of return on the existing trust funds, no additional contributions are necessary for SONGS 1 and Palo Verde. Due to changed circumstances, including healthy Trust Fund growth, SCE has deferred any increases for SONGS 2 and 3 after the first quarter of 2014, pending review of the recently filed more-detailed site specific decommissioning cost estimate. SDG&E is authorized to maintain its previously authorized trust fund contributions of $8.07 million through 2014, but similarly any additional contributions will be considered in connection with review of the 2014 estimate.

Based on the record, for DCPP, the Commission finds reasonable a cost estimate of $2.288 billion, a reduction of $497.89 million from PG&E's estimate of

$2.786 billion, which results in approximately a 25% increase[3] over the 2009 NDCTP approved estimate.   We also find reasonable for PG&E to collect the revenue requirement to make the annual contributions of approximately $120.100 for HBPP3 decommissioning costs, and approximately $10 million for Safe Long-Term Protective Storage expenses at HBPP.

1. Requests

1.1. Southern California Edison (SCE) and San Diego Gas and Electric Company (SDG&E)

In a Joint Application filed on December 21, 2012, Application (A.) 12-12-013, SCE and SDG&E request that the Commission find:

(1) the $14.9 million[4] (100% share, 2011$) cost of San Onofre Nuclear Generating Station (SONGS) Unit 1 decommissioning work completed between January 1, 2009 and December 31, 2012 is reasonable;

(2) the updated $182.3 million (100% share, 2011$) SONGS Unit 1 decommissioning cost estimate for the Remaining Work is reasonable; and

(3) the updated $ 4,119.0 million (100% share, 2011$) SONGS Units 2 & 3 decommissioning cost estimate is reasonable.

In addition, SCE requests the Commission:

(1) find the updated $513.5 million (SCE's share, 2010$) Palo Verde (PV) decommissioning cost estimate is reasonable;

(2) authorize rate recovery of its increased contribution of $39.221 million for contributions to its Nuclear Decommissioning Trust Funds for SONGS Units 2 & 3 through the Nuclear Decommissioning Adjustment

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3 The 2009 adopted estimate was always presented as 2008$, while all amounts in the 2012 estimates are in 2011$.

4 SCE modified this amount to $13.9 million in SCE-20.

Mechanism (NDAM), effective January 1, 2014. The associated 2014 revenue requirement associated with this contribution is $39.662 million.

In addition to the foregoing, SDG&E requests the Commission:

(1) find that the updated estimates of SDG&E's ratable share of the ND costs for SONGS Units 2 and 3 of $36.46 million, $400.625 million, and $423.093 million, respectively, are reasonable;

(2) authorize a revenue requirement for SDG&E's annual contribution to its Nuclear Decommissioning trust Fund for SONGS Units 2 and 3 in the amount of $16.43 million, effective January 1, 2014;

(3) authorize SDG&E to amortize the 2013 forecasted NDAM balancing account undercollection in rates for a 12-month period beginning January 1, 2014; and

(4) authorize SDG&E to file an advice letter within 15 days after the effective date of the Commission's order approving this application to adjust SDG&E's NDAM rates to reflect the annual contributions and revenue requirements as may be approved by the Commission.

In comments on the Proposed Decision (PD), SCE and SDG&E acknowledged "changed circumstances," including permanent shutdown of SONGS 2 and 3 and "healthy" trust fund growth, as the basis to revise their estimated contributions and related revenue requirements. During 2014 and 2015, SCE does not anticipate needing any additional funding other than $5.681 million collected in the first quarter 2014 (1Q2014).[5] SDG&E now asks the Commission to stay any increases and to allow SDG&E to continue to annually collect the previously approved 2009 amount of $8.07 million, pending a final

[5] SCE Opening Comments at 2.

decision on the Joint Application to approve a site-specific decommissioning cost estimate.[6] (*See* § 9.4 of this decision for more detail.)

Furthermore, SDG&E now requests the amortization of the 2014 forecasted NDAM overcollection of $0.7 million be approved for 2015 rates. According to SDG&E, this adjustment reflects the transfer of funds from SDG&E's non-qualified trusts to its qualified trusts, an appropriate allowance for franchise fees and uncollectibles of 1.0275% and .1410%, respectively, and funds received from SCE representing SDG&E's ratable share of an award of civil damages related to the failure of the United States Department of Energy to begin accepting spent nuclear fuel from SONGS Units 1, 2 and 3.

1.2. Pacific Gas and Electric Company (PG&E)

In a separate application, A.12-12-012, later revised,[7] PG&E requests as part of Phase 2, that the Commission do the following:

(1) authorize the collection, through Commission-jurisdictional electric rates, effective January 1, 2014, of $80.003 million for the Diablo Canyon Nuclear Decommissioning Trusts for Units 1 and 2, respectively (the 2012 revenue requirement is $9.13 million);

(2) authorize PG&E to collect through Commission-jurisdictional electric rates effective January 1, 2014, $120.100 million in annual revenue requirements for the Humboldt Unit 3 Nuclear Decommissioning Trusts;

[6] SDG&E Opening Comments at 3.

[7] PG&E-22 at 8-2 to 8-3.

(3) authorize PG&E to collect through Commission-jurisdictional electric rates for funding Humboldt Unit 3 Safe Long - Term Protective Storage (SAFSTOR)[8] operation and maintenance (O&M) costs an estimated $10.005 million in 2014, with nominal decreases in 2015 and 2016.;

(4) find that the decommissioning cost estimates and associated trust contribution analyses are reasonable and in accordance with §§ 8321 through 8330 of the Cal. Pub. Util. Code;[9]

5) authorize PG&E to continue to collect the revenue requirement associated with ND trust contributions and Humboldt Unit 3 SAFSTOR O&M costs through a nonbypassable charge as specified in Pub. Util. Code § 379, and to continue to utilize the NDAM as authorized in Decision (D.) 99-10-057; and

(6) affirm PG&E's treatment of revenue requirements and trust contributions in 2013.

Disposition of these proceedings is time-sensitive for the utilities. As PG&E states, the company must obtain a new Internal Revenue Service (IRS) Schedule of Ruling Amounts (SRA) reflecting the updated funding assumptions approved by the Commission in this Nuclear Decommissioning Cost Triennial Proceedings (NDCTP), and Federal Treasury regulations require that the SRA for contributions beginning in 2014 be calculated based on fund balances as of December 31, 2013.[10] This deadline is applicable to all the utilities.

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[8] SAFSTOR is a method of decommissioning in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use. http://www.nrc.gov/reading-rm/basic-ref/glossary/safstor.html.

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

[10] PG&E OB at 28; PGE-20 at 3-11; Treas. Reg. § 1.468A-3(e)(2)(viii)(C).

2. Procedural History

The Commission preliminarily categorized these proceedings as ratesetting[11] and affirmed the categorization in the Scoping Memorandum and Ruling (Scoping Memo) issued on June 17, 2013. The Office of Ratepayer Advocates (ORA)[12] protested both applications.

A joint prehearing conference (PHC) for both Applications was held on March 27, 2013. At the PHC, assigned Commissioner Mark Ferron[13] and Administrative Law Judge (ALJ) Melanie M. Darling consolidated the proceedings without objection and ordered the utilities to serve the following Supplemental Testimony and exhibits, as relevant to Phase 2:

(1) SCE, in consultation with SDG&E, shall prepare and serve, no later than April 26, 2013, a ND cost estimate which reflects the potential scenario of early decommissioning following a permanent shutdown of one or both SONGS units;

(2) SCE, SDG&E, and PG&E shall prepare and serve an exhibit, no later than April 10, 2013, that identifies all proceeds from litigation (e.g., judgment, settlement) with the U.S. Department of Energy related to disposal of spent nuclear fuel, what periods the proceeds cover, and how the utility proposes to treat the funds, including estimated refunds to ratepayers and the anticipated mechanism for refund (e.g., General Rate Case, Energy Resource Recovery Account (ERRA), NDAM); and

11 Resolution ALJ 176-3307 (January 10, 2013).

12 ORA, formerly known as Division of Ratepayer Advocates, submitted its evidence and briefs marked as "DRA," a designation we keep here for exhibit reference to match the evidentiary record.

13 The consolidated proceedings were re-assigned to Commissioner Michael Peevey in February 2014, and re-assigned to Commissioner Michel Florio on April 16, 2014.

(3) SCE, SDG&E, and PG&E shall prepare and serve, no later than April 10, 2013, a summary of actual Trust Fund performance covering 2009-2012 and include a comparison with the prior NDCTP forecast performance, as ordered by D.13-01-039.

All three utilities submitted and served the exhibits and testimony requested by April 10, 2013. However, SCE requested and obtained several extensions to serve its alternate decommissioning scenario. On June 7, 2013, SCE announced that it would retire SONGS Units 2 and 3. The early decommissioning scenario was eventually served on July 22, 2013.[14]

Due in part to these delays, PG&E requested that Humboldt Bay Power Plant 3 (HBPP) cost reviews be heard on the original schedule in order to get a decision by December 2013. All parties agreed to bifurcate the proceedings into two phases: Phase 1 to be heard on the original schedule would consider the reasonableness review of the identified past & future decommissioning costs at HBPP (i.e., decommissioning cost estimate, SAFSTOR[15] O&M, and costs of completed decommissioning projects.)

All other issues in the proceedings were assigned to Phase 2, to determine the annual revenue requirement reasonably necessary to adequately fund the decommissioning trust fund created by each utility for each nuclear power plant. Therefore, in Phase 2 we examined the underlying forecasts and assumptions to estimate the future costs of decommissioning the various nuclear generating

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14 SCE-12 Work Papers supporting 2013 Early Decommissioning Scenario for SONGS Units 2 and 3 (SCE-6).

15 SAFSTOR is a method of decommissioning in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use.http://www.nrc.gov/reading-rm/basic-ref/glossary/safstor.html.

stations (excluding HBPP); the costs and earnings associated with the decommissioning trust funds and review of the management of the trust funds; and other relevant data, policies or laws and regulations. Phase 2 also undertook the standard reasonableness review of managerial decisions and actions by SCE and SDG&E as they have pursued decommissioning at SONGS Unit 1.

The applicants shall also demonstrate that they are in compliance with all relevant decisions, including D.10-07-047, the combined Phase 1 decision for the 2009 NDCTP, and D.11-07-003, which adopted the recommendations of the Independent Review Panel in Phase 2.

The utilities supported their applications with direct and rebuttal testimony, as well as ordered supplemental testimony. The Utility Reform Network (TURN) and the Commission's ORA served timely reply testimony and participated in the hearings. Although several groups belatedly asked to become parties,[16] only Alliance for Nuclear Responsibility (A4NR) and Coalition to Decommission San Onofre (CDSO) were granted party status. CDSO's Amended Motion for Party Status was granted with restrictions.[17] CDSO's Reply testimony did not conform to the restrictions on participation. A4NR did not

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16 ALJ Ruling (September 13, 2013) (Coalition of California Utility Employees and Laborer's International Union of North America, local #89 were denied party status for failure to meet the qualifications of Rule 1.4.

17 ALJ Ruling on Party Status (September 16, 2013) (CDSO's Amended Motion for Party Status (September 16, 2013) identified issues of interest which were outside the scope of the proceedings, particularly issues within the jurisdiction of the U.S. Nuclear Regulatory Commission. However, CDSO identified two issues which were within the scope, and CDSO was granted restricted party status to provide expert testimony (1) on the practical and economic consequences of SCE commencing active decommissioning immediately, instead of waiting for NRC review; and (2) to dispute SCE's assumption that a permanent repository for spent nuclear fuel will not be available until 2027, including calculation of the commensurate additional revenue requirement).

submit testimony in Phase 2, but both CDSO and A4NR participated in the hearings.

Evidentiary hearings were held on Phase 2 on October 21 through October 25, 2013. At the conclusion of the hearings, the underlying testimony of witnesses in this phase of the proceeding, and other prepared exhibits, were received into evidence without objection. Subsequent to the evidentiary hearings, SCE moved for admission of late exhibits; the motions are hereby granted as follows:

- SCE-20 an update to reduce the amount of costs incurred for SONGS 1 decommissioning work from $14.9 million (100% share, 2011$) to $13.9 million (100% share, 2011$);
- SCE-21 updated Funding Assurance Letter to NRC for SONGS 1;
- SCE-22 updated Funding Assurance Letter to NRC for SONGS 2 and 3; and
- SCE-23 updated Funding Assurance Letter to NRC for Palo Verde Units 1, 2, and 3.

Concurrent Opening Briefs and Reply Briefs were filed by SCE, SDG&E, PG&E, ORA, TURN, A4NR, and CDSO on December 16, 2013 and on January 24, 2014, respectively. CDSO's January 27, 2014 amended motion, opposed by SCE and SDG&E, to hold a hearing on various issues, many outside the scope or duplicative of the proceedings, was denied.

On March 5, 2014, the Commission adopted D.14-02-024 in Phase 1, which established, as reasonable, a cost estimate of $679 million (2011$) to complete the decommissioning of HBPP. It also approved SAFSTOR O&M expense forecasts and expenditures for completed decommissioning projects at HBPP.

On April 29, 2014, the ALJ granted PG&E's unopposed motion for authority to record to the existing NDAM its 2014 nuclear decommissioning revenue requirement as of January 1, 2014, after PG&E receives a final decision in both phases of its 2012 NDCTP application. PG&E's request for interest, based on the Federal Reserve three-month commercial paper rate, was also granted.[18]

The matter is submitted as of April 29, 2014 upon issuance of the ruling which allowed PG&E to record decommissioning revenue requirement, including for Diablo Canyon Nuclear Power Plant (DCPP), upon adoption of a final decision in Phase 2.

3. Standard of Review

The California Nuclear Facility Decommissioning Act of 1985 requires the utilities to submit periodic decommissioning cost estimates to the Commission, which include certain information, e.g., the effects of regulation, technology and economics affecting the estimate. The Commission reviews these estimates for purposes of establishing rates and charges, and the estimated service life of the facilities.

The utilities bear the burden of proof in this ratesetting proceeding to show, by a preponderance of evidence, that the proposed cost estimates for completing decommissioning of SONGS 2 and 3, Palo Verde, and Diablo Canyon, and to maintain SAFSTOR conditions during decommissioning, 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.

[18] ALJ Ruling Granting Interim Ratemaking Mechanism (April 29, 2014).

Consistent with prior Commission findings, the prudency of a particular management action (e.g., decision to undertake a specific activity) depends on what the utility knew or should have known at the time that the managerial decision was made.

Full decommissioning, remediation and restoration of sites formerly used for nuclear generation is generally estimated to take 50-60 years. Therefore, in approving decommissioning cost estimates and resulting contributions from current ratepayers, the Commission is mindful of our strong preference for limiting potential intergenerational equities.[19]

Furthermore, the Commission has an interest in ensuring sufficient funds and best practices are applied to maintain the safety of the public and staff after shutdown. Nonetheless, we also acknowledge TURN's reminder of our oft-stated view that adoption of "conservative" assumptions does not mean consistently higher estimates of future costs.[20]

4. Common Assumptions and Common Issues for Utility Decommissioning Cost Estimates

Pursuant to D.11-07-003, SCE, SDG&E (Utilities) and PG&E submitted, in common summary format, common assumptions and results for SONGS 2 and 3 and DCPP 1 and 2.[21] The three utilities commonly assumed:

- DOE will start accepting spent nuclear fuel (SNF) in 2024 (four years later than in the 2009 cost estimate);
- trust funds will pay for "staff termination costs" per Pub. Util. § 8330 for displaced utility personnel after permanent

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[19] *See, e.g.,* D.95-12-055, 63 CPUC2d 570 at 612.

[20] TURN OB at 2 (citing, D.00-02-046).

[21] Utilities-11.

shutdown, and after termination of decommissioning projects;

- all site improvements (both radioactive and non-radioactive) will be removed; all radioactive material will be disposed of at licensed Low Level Radioactive Waste (LLRW) facility; and
- similar LLRW disposal rates, only significant difference is for Greater Than Class C (GTCC) where SONGS uses $8,500 per cubic foot while Diablo Canyon's estimate assumes $6,119 per cubic foot.

No party opposed removal of all contaminated material or the LLRW burial costs. All parties seem to agree that there is significant uncertainty as to when the DOE and Congress will fulfill the U.S. Government's promise to the public to provide long-term storage of nuclear waste. On the other hand, whether decommissioning funds should be used to pay for arbitrary severance payments is a disputed issue.

4.1. Common Issues

There are several issues common to all, or most, of the decommissioning cost estimates. These issues are discussed below.

4.1.1. Severance Expenses

The utilities have historically differed over inclusion of "severance" or "termination" packages in their NDCTP cost estimates. Although SCE claims it has included these costs in previous NDCTP cost estimates, PG&E first included a severance cost estimate in this 2012 NDCTP decommissioning cost estimate. No severance or similar payments have been made through the HBPP Unit 3 ND Trust.[22] In 2009, SCE's argument that such costs were required by law was

[22] PG&E OB at 31.

unchallenged. The interpretation of § 8330 is at issue in this 2012 proceeding, and discussed below.

SCE provided a brief description of internal and external job fairs and workshops it hosted for severed employees after June 7, 2013. In addition, SCE explained its employee assistance program "provides for cash severance, educational reimbursement and outplacement, and extended health coverage.[23] The benefits are subject to gradations to reflect the employee's age, years of service, and job classification.[24] The Utilities argue that severance payments to utility employees who become unemployed following closure and decommissioning of a nuclear facility are within the scope of decommissioning costs and may be paid from Qualified Nuclear Decommissioning Trust Fund (NDTFs).[25] SCE states its recovery is based on recorded amounts and not on the forecast.

PG&E deferred any description of its future staff termination assistance program at DCPP, but argued that such payments are legal.[26] PG&E asserts the statute is for the benefit of displaced nuclear workers, and should, therefore, "not be interpreted to limit the specific type of assistance which could be provided. That is particularly true since, given the changes in the electric industry structure, there are very restricted opportunities for comparable utility employment elsewhere."[27] In this proceeding, PG&E adopted a forecasted

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[23] SCE-8 at 24-25.

[24] *Id* at 24.

[25] SDG&E OB at 40.

[26] PG&E OB at 32.

[27] PG&E OB at 32.

estimate based on an assumed payment times the number of expected employees. According to PG&E, the specific plan for treatment of workers displaced by plant shut down should be determined as a part of a site specific decommissioning plan and after consultation with union representatives.

TURN expressed qualified support for utility requests to include NDTF payment of severance costs by stating it would approve of an additional $148.4 million in costs for severance if the Commission found it appropriate.[28] CDSO recommends that SCE, (1) place displaced employees in other jobs with SCE or its affiliates; and (2) give these employees "first opportunity" for decommissioning jobs years in the future. SCE replies these are "empty" suggestions."[29] Not only are there a lack of comparable vacancies within SCE's and affiliates' operations, adds SCE, the workforce is not fungible and the types of skills for employees at an operating plant are different than those in decommissioning.[30]

For SONGS employees, SCE estimated the cost-per-person to be $98,000 for 1470 [31] employees. PG&E estimated staff termination costs as $82,400 per person applicable to about 1487 employees. Both utilities used base salary and years of service to calculate the severance amounts. No utility provided a budget or a description of the calculations. SCE's description of the types of assistance provided was general, and omitted any analysis of the accessibility of the programs and benefits, or any measure of the programs' effectiveness.

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[28] TURN OB at 3.

[29] SCE-8 at 23.

[30] *Ibid.*

[31] SCE-6 at 8 (SCE revised the number of employees from 1675 to 1470).

Two statutes within the Nuclear Facilities Decommissioning Act support the utilities' view that decommissioning cost estimates may include employee severance costs for displaced workers. Section 8322(g) provides, in relevant part:

> 8322. The Legislature hereby finds and declares all of the following…
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> ….(g) Decommissioning nuclear facilities causes electric utility employees to become unemployed through no fault of their own, and **these employees are entitled to reasonable job protection the cost of which are properly includable in the costs of decommissioning**. [Emphasis added.]

Section 8330 reads, as follows:

> Every electrical utility involved in decommissioning, closure, or removal of nuclear facilities, **shall provide assistance in finding comparable alternative employment opportunities for its employees who become unemployed as the result of decommissioning, closure, or removal.** The Commission or the board shall authorize the electrical utility to collect sufficient revenue through electrical rates and charges to recover the cost, if any, of compliance with this section. [emphasis added.]

During hearings the question was raised as to whether state law requires ratepayers to pay arbitrary "severance packages" for utility workers terminated after SCE's notice of shutdown on June 7, 2013. In post-hearing briefs, both CDSO and TURN expressed uncertainty on the matter. The Commission has not previously been compelled to interpret the obligatory parameters of this statute, or whether any such disbursements might jeopardize the tax status of the Qualified NDTFs.

We are persuaded by the utilities' arguments that state law permits utility recovery for some form of employee assistance which may be characterized as decommissioning costs. However, neither SCE nor SDG&E provided more than a minimal description of the program that provided assistance to employees in "finding comparable alternative employment opportunities," nor a breakdown of how the per person severance packages were calculated.

PG&E concedes that severance is not the only form of assistance which could be provided to employees, but, consistent with prior Commission decisions, PG&E concludes that severance costs are an acceptable means of complying with the law.[32]

We are still bound by the requirement of Pub. Util. § 451 to only approve rates if they are just and reasonable. In these proceedings, no party expressly objected to the Utilities thin description of the program, nor contested the development of, or actual amount of, the estimated severance amounts. No evidence was submitted to contradict the amounts or to suggest the amounts are unreasonable.

Therefore, the Commission finds that reasonable employee assistance costs may be considered decommissioning costs for utility employees who become unemployed due to the closure and decommissioning of a nuclear facility. However, we also agree with SDG&E, that employee severance costs should only be paid with Qualified Trust Funds, and only if the Trusts' qualified tax status pursuant to Internal Revenue Code Section 468A is not jeopardized.

The SCE and SDG&E represented that each has requested or received a Private Letter Ruling (PLR) from the IRS affirming that use of Qualified NDTFs for the SONGS severance expenses will not jeopardize the Qualified status of the disbursing trust fund. The PLR should be included with SCE or SDG&E Tier 2 Advice Letters (AL) to the Commission which seeks approval to withdraw

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32 PG&E OB at 32.

incurred severance costs from the Qualified NDTFs. The AL should include a detailed description of the program for "assistance in finding comparable alternative employment opportunities" for workers displaced due to the SONGS shutdown after June 7, 2013.

Moreover, as part of its application for approval of the 2014 detailed site-specific cost estimate, or in supplemental testimony provided in support of the application, SCE should include any additional information applicable to potential employee assistance costs forecast for 2015 and thereafter. For example, SCE shall include a description of the displaced employee assistance program, its estimated budget, and how the severance packages are calculated.

4.1.2. Federal Pre-emption

Some of the advice and recommendations from intervenors, appear to ignore the distinct jurisdictional roles of the federal and state government regarding nuclear safety, operational issues, and decommissioning a closed nuclear facility.

The Atomic Energy Act of 1954[33] provided the federal government with exclusive jurisdiction to license the transfer, delivery, receipt, acquisition, possession, and use of nuclear materials.[34] Congress, in passing the 1954 Act and later amendments, intended that "the U.S. Government should regulate the radiological safety aspects involved in the construction and operation of a nuclear plant, but that the States retain their traditional responsibility in the field

[33] 42 U. S. C. § 2011 *et seq*.

[34] *PG&E v. State Energy Resources Conservation and Development Commission* (1983), 461 U.S. 190, 207.

of regulating electrical utilities for determining questions of need, reliability, cost, and other related state concerns."[35]

In a 1983 pre-emption test of state law, the U.S. Supreme Court affirmed the Federal Government maintains complete control of the safety and "nuclear" aspects of energy generation; and that states have "no role" regarding the license, transfer, delivery, receipt, acquisition, possession, and use of nuclear materials.[36]

For example, issues regarding the type of nuclear fuel used in operations, the type of casks used for dry storage, the operation of the SNF pool, are federal jurisdictional matters. As an example of this federal authority, to receive an NRC operating license, one must submit a safety analysis report, which includes a radioactive waste handling system.[37] The regulations specify general design criteria and control requirements for fuel storage and handling and radioactive waste to be stored at the reactor site. [10 C.F.R. pt. 50, app. A (1982).] In addition, the NRC has promulgated detailed regulations governing storage and disposal away from the reactor. [10 C.F.R. pt. 72 (1982).] Lastly, The NRC issued its first nuclear decommissioning requirements in 2000.[38]

4.1.3. Spent Nuclear Fuel Management

The parties raised several issues related to the spent fuel management costs in connection with the decommissioning estimates. The two basic common issues are whether it is reasonable to (1) assume the DOE will begin accepting

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[35] *Id.* at 205.

[36] *Id.* at 207.

[37] 10 C.F.R. § 50.34(b)(2)(i), (ii) (1982), and 150.15(a)(1)(i) (1982).

[38] NRC Research Guide 1.184 (Decommissioning of Nuclear Power Reactors (July 2000) http://pbadupws.nrc.gov/docs/ML0037/ML003701137.pdf .

SNF in dry cask storage for long-term storage in 2024; and (2) assume that SNF requires a 12-year cooling period from reactor to dry storage.

As discussed above, the NRC has exclusive jurisdiction over the utilities' operational choices regarding SNF management. The utilities also submitted documentation to support the two assumptions, including compatibility with their NRC operating license and NRC regulations.

4.1.3.1. DOE Acceptance of Spent Fuel

Based on DOE and other public documents, the utilities' determined to utilize 2024 as DOE's start-up year, and assume that DOE will accept SNF according to previously disclosed priorities. CDSO disagrees and relies on a DOE publication, not in the record, to support its view that DOE is not likely to site and build a repository before 2042, or be able to accept California-sourced SNF before 2048.[39] According to SCE, CDSO omitted another reference, in the same report, to DOE's intention to license an interim storage facility by 2025.[40]

The utilities rely on DOE information which has not been updated for at least one triennial cycle, and a recent Court of Appeals decision,[41] which SCE views as a mandate that the NRC promptly continue with the licensing process for DOE to store waste at Yucca Mountain. We find there is little more than speculation in the record to support the projected date when DOE will begin to accept SNF for long-term storage. Many complex technical, political, and administrative decisions will eventually drive the development by DOE of any interim or long-term storage of SNF. We agree that 2024 is optimistic, and the

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39 CDSO-20 at 12.

40 SCE-8 at 18.

41 *Id.*; *see In re Aiken County*, 2013 U.S. App. LEXIS 16987 (D.C. Cir. 2013).

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 2024. Thus, substitution of an unsupported alternative, as suggested by some parties, would be less reasonable than DOE's own position in the record, even if we are skeptical of a near-term political solution at the NRC, the courts or in the U.S. Congress.

Therefore, we find, for purposes of making cost estimates in the 2012 NDCTP, it is reasonable to assume that DOE will not begin to accept SNF for long-term storage prior to 2024.

4.1.3.2. Transfer of Spent Fuel from Wet Pools to Dry Storage

The SONGS and DCPP cost estimates both assume that some spent fuel assemblies will require 12 years of wet cooling in the SNF pools before being transferred to dry cask storage.[42] TURN and A4NR insist that SCE and PG&E have not adequately supported that cooling period, which TURN claims is at odds with the industry's 5-6 year timeline.[43]

The TLG cost study for DCPP sheds light on the parties interests related to the time spent fuel assemblies stay in the spent fuel pool which requires SCE and PG&E to incur high labor and systems decommissioning costs to ensure safety and security at the sites. Some intervenors suggest the Commission press the

[42] TURN OB at 27.

[43] *Id.* at 29.

utilities to make changes in the heat loads of fuel assemblies brought to the SNF pools, or take other steps to shorten the time necessary to maintain the pool. Their clear aim is to reduce costs and limit the time spent fuel remains stored in arguably higher risk wet pools than in dry storage.

> "The current [DCPP] Part 72 ISFSI license does not allow dry cask storage of spent fuel with burnups above 45,000 MWD/metric ton. It is assumed that PG&E can amend the Part 72 license to store the higher burnup fuel, but that as a condition of the amendment it will require longer decay times (12 years) before storing the spent fuel in the casks."[44]

TURN describes testimony from both SCE and PG&E witnesses which appears to open the door to some methods of grouping fuel to result in shorter than 12-year cooling periods, depending on other spent fuel available for packing into a dry cask.[45] TURN recommends the Commission direct SCE and PG&E to "pursue all practical strategies" to reduce the cooling periods at their respective facilities, in order to minimize costs.[46]

A4NR also contested the reasonableness of the assumed timeframes for transfer of SNF from wet to dry storage at DCPP and SONGS.[47] A4NR focused its final argument only on DCPP (finding the issue moot as to SONGS for now due to SCE's stated intent to pursue transfer as soon as practicable and its request to stay any increase to ratepayers). In particular, A4NR relies on a recommendation included in the California Energy Commission's bi-annual

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44 PG&E-24, TL:G 2012 DCPP Cost Study at vii of xix, FN 2.

45 *Id.* at 28-29; See, SCE-8 at 16-17.

46 TURN OB at 27.

47 A4NR OB at 1.

Integrated Energy Policy Reports (IEPR). The statutory basis for the IEPR is in § 23500 et seq. of the Pubic Resources Code, which provides in relevant part:

> 25302 (a) Beginning November 1, 2003, and every two years thereafter, the [Energy] commission shall adopt an integrated energy policy report. This integrated report shall contain an overview of major energy trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment….
>
> …(f) For the purpose of ensuring consistency in the underlying information that forms the foundation of energy policies and decisions affecting the state, those entities [e.g., CPUC] shall carry out their energy-related duties and responsibilities based upon the information and analyses contained in the report. If an entity listed in this subdivision objects to information contained in the report, and has a reasonable basis for that objection, the entity shall not be required to consider that information in carrying out its energy-related duties.

§ 25303(c), in relevant part:

> "In the absence of a long-term nuclear waste storage facility, the [Energy] commission shall assess the potential state and local costs and impacts associated with accumulating waste at California's nuclear power plants."

A4NR criticizes PG&E's failure to update its assumptions after the 2008 decommissioning cost estimate, or to respond to CEC's IEPR recommendations (most recently in the 2013 IEPR[48]) to alter its assumed pace of transfer.[49] For example, the centerpiece of A4NR's argument is this recommendation (there is a similar recommendation for SCE about SONGS):

> To reduce the volume of spent fuel packed into Diablo Canyon's storage pools (and consequently the radioactive material available for disposal in the event of an accident or sabotage), PG&E should, as soon as practicable, transfer spent fuel from the pools into dry casks, while maintaining compliance with NRC spent fuel cask and storage requirements and report to the Energy Commission on its progress until the pools have been returned to open racking arrangements.[50]

A4NR concludes that PG&E failed to establish a reasonable basis for increasing ratepayer contributions to DCPP trusts for SNF management without considering other timeframes. Furthermore, A4NR characterizes PG&E's lack of responsiveness to the CEC recommendations as "defiance."[51]

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48 http://www.energy.ca.gov/2013_energypolicy/

49 *Id*. at 10.

50 A4NR-27 at 2-3 (Draft IEPR October 2013 at 156-157) (CEC adopted Final 2013 IEPR on February 14, 2014); In the current and earlier IEPRs, the CEC also recommended that PG&E undertake additional evaluations of (1) impacts and costs of fuel storage options; (2) the structural integrity of the spent fuel pools; and (3) the utility's annual capability of moving SNF to dry cask storage. There is no record here of whether PG&E has responded to, or implemented, any of the identified evaluations.

51 A4NR OB at 14, 16.

The utilities consider all aspects of SNF management to be pre-empted by federal law. PG&E insists the company currently manages its spent fuel at DCPP in full compliance with NRC requirements, and the NDCTP is not an appropriate forum for evaluating PG&E's spent fuel practices. PG&E states it has "provided a conservative assumption, in line with PG&E's current practices, for purposes of estimating the costs of decommissioning in this NDCTP."[52]

SDG&E similarly rejects A4NR's characterization and disputes the Commission's jurisdiction to specify the manner in which SNF should be handled, processed, stored, and/or transferred.[53] Without conceding this Commission or any other state agency has any jurisdiction over the issues raised by A4NR, SDG&E submits there are substantial other grounds upon which A4NR's recommendations should be dismissed. For example, SDG&E notes the statutes upon which CEC prepares its report, do not vest in any agency new regulatory authority.[54] Consequently, SDG&E concludes the IEPR does not compel "considerable deference" to the report or its finding.

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[52] PG&E 23 at 2-2.

[53] SDG&E Reply Brief (RB) at 5.

[54] *Ibid*.

Moreover, PG&E asserts the timing of the movement of SNF involves numerous factors not considered by A4NR, and the loading of SNF assemblies into the Independent Spent Fuel Storage Installation (ISFSI) is controlled by its NRC-issued ISFSI license. According to PG&E, there is a minimum cooling period of five years but the utility must consider additional criteria prior to loading an assembly into a cask for storage, (e.g., the decay heat produced by the assembly and the total decay heat in the cask.[55] PG&E contends both values are more restrictive than the five year minimum cooling time. Thus, for example, assemblies after seven years may be loaded if older cooler assemblies are included in order to meet the limitation on the total heat load in a cask. According to PG&E, a more representative nominal cooling time for loading casks "would be closer to ten years or more."[56]

PG&E also criticizes A4NR's arguments as lacking any record support, and rejects A4NR's view that the Commission "should consider the CEC's policy favoring accelerated transfer."[57]

A4NR sought implementation of CEC's recommendations in PG&E's 2014 General Rate Case (GRC) and referred to the Commission's GRC decision to bolster its claims in this proceeding. However, in PG&E's GRC decision, the Commission adopted PG&E's forecast ISFSI costs for transfer and storage of SNF, subject to PG&E filing a plan in the next GRC to comply with the CEC recommendations to transfer SNF from wet to dry storage as soon as

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[55] TURN-18 at 1 (TURN-PG&E-010 Q23).

[56] *Ibid.*

[57] PG&E RB at 23; A4NR OB at 5.

practicable.[58] This result is something less than recognition of Commission authority to impose spent fuel management practices on SCE or PG&E; but establishes our oversight interest in confirming the utilities are actively engaged with the NRC to apply best efforts toward implementing the state's interests in minimizing costs and risks at the nuclear facilities.

A4NR continues to assert that the IEPR is an important policy document which should be advanced by the Commission in this decision. We agree the IEPR is an important policy document that includes recommendations to the utilities. We expect the utilities to be mindful of its recommendations, as well as technological changes and best practices in the area of SNF storage.

On a different issue, SCE contends TURN is mistaken when it claims the common industry assumption for wet-to-dry storage is five years.[59] According to SCE, their NRC license imposes a minimum wet cooling period of five years for each spent fuel assembly, removed from the reactor until transfer to dry storage. The license also includes tables that specify minimum cooling times, sometimes "substantially greater than five years" for some types or conditions of fuel. SCE asserts the longer cooling period is reasonable due to longer cooling requirements for some fuel assemblies, and assumed a 10-year cooling for control element assemblies and other materials stored in the SNF pool. Therefore, the 12-year cooling period is a "bounding assumption" for estimating purposes.[60]

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[58] D.14-08-032 at 412-413, 737 (Conclusion of Law 29(b)).

[59] SCE-8 at 16.

[60] *Ibid.*

We are persuaded that the 12-year wet cooling period assumed and supported by the utilities, is allowed by their respective NRC licenses, and is reasonable for purposes of estimating triennial decommissioning costs in the 2012 NDCTP. Nonetheless, this is not a finding that what is suitable for high level cost estimation purposes, will necessarily be the appropriate determination of actual future operating decisions. The utilities should be considering the regulatory and economic impacts of taking steps to transfer SNF to dry cask storage as soon as practicable.

Our acceptance of the 12-year assumption, also does not mean the Commission or the utilities lack interest in reasonable and permissible actions that may lead to SNF leaving the SNF pools earlier. However, due to federal pre-emption on safety and radiological matters at a nuclear facility, the state's interest is primarily an economic one. The record was insufficient to estimate comparable annual costs for wet versus dry storage, particularly post-shutdown when the wet pools are used for other decommissioning purposes. Instead, the evidence establishes that a licensee, like SCE, will have to submit its spent fuel management plan to the NRC for review. Additionally, the utilities may achieve economies when packaging SNF, assuming different levels of radiation.

While it is conceivable an intervenor could establish a clear economic argument for changes to NRC-regulated SNF operations, the Commission is not presented with those facts here, and the related jurisdictional issue need not be resolved in this decision. In the 2015 NDCTP, the utilities shall address the disparate costs of wet versus dry storage in their applications.

4.1.4. DOE Litigation Proceeds

As a condition of its license, every nuclear power plant operator is required to enter a standard SNF disposal agreement with the U.S. Department of Energy (DOE). These agreements provide that DOE will start accepting SNF starting January 31, 1998 to transport it to a permanent repository. However, no permanent repository has been established. Along with other nuclear plant owners, SCE and PG&E eventually filed lawsuits to recover costs incurred to store SNF on-site after it was due to be picked up. The recovery from DOE of some SNF storage-related costs varies among the utilities; some storage costs were not paid as decommissioning costs so that ratepayer credits occur outside the ND trust Funds.

TURN urges the Commission to remove certain spent nuclear fuel storage costs from the decommissioning cost estimates to reflect the fact that damage payments will be made.[61] TURN's estimated costs for all three utilities, only for post-shutdown ISFSI dry storage costs through the end of decommissioning, total just over $1 billion.

4.1.4.1. The Utilities Supplemental Testimony

At the prehearing conference, the ALJ directed all three utilities to file supplemental testimony to describe what awards of damages or settlement proceeds each company had obtained from the DOE and to identify where or how the funds had been allocated. Each utility filed such testimony, and stated the net DOE proceeds were credited through one of the company's adjustment

61 TURN OB at 30.

mechanisms allocated based on where costs were incurred, e.g., through general rates, ERRA, or the utility's NDAM.[62] A brief description is provided below:

- SCE, on behalf of the SONGS owners, received a favorable court ruling and order, and received damage payments related to costs incurred January 1998 through December 2005.; disposition of SCE's share of $111 million was deferred to A.12-04-001, ERRA review of operations.[63]
- SDG&E reported it received $28.462 million from SCE as its allocable share of the SCE award; SDG&E credited $15.3 million to the NDAM, and the remaining amount of $13.16 million was credited to accounts where the underlying costs had been incurred.
- PG&E entered a settlement with DOE for costs through 2012 and established a process for claims through 2012; the net proceeds of approximately $259 million were divided between HBPP and DCPP, 49% and 51%, respectively.[64]

No party objected to the utilities' supplemental testimony. The utility testimony appears to establish that to the extent recovered ISFSI costs were paid for with decommissioning funds, recovery was credited to decommissioning liabilities.

4.1.4.2. TURN's Proposal to Reduce Cost Estimates

The utilities continue to include in their current decommissioning cost estimates, anticipated costs related to post-shutdown dry fuel storage.

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62 SCE-5, SDG&E-6, and PG&E2.

63 SCE-5 at 1; SCE-19 (Description of SCE's DOE litigations proceeds for SONGS 1, 2, and 3, and allocations to co-owners).

64 PG&E-2 at 1, (PG&E reached a settlement, and received damage payments).

TURN contends this is error because every claim filed by the utility companies against the DOE has been successful.[65] The record establishes SCE and PG&E have received recovery for costs including additional SNF pool storage, dry storage, modifications to existing plant for interim storage, property taxes and related overheads.[66] Therefore, TURN asks the Commission to conclude these damage awards are a predictable certainty at least as to post-shutdown dry storage costs, and to reduce the decommissioning cost estimates to reflect potential future damage awards.[67] To do otherwise, TURN claims, is to ensure intergenerational inequity,[68] with future ratepayers obtaining the benefit of overcollections decades from now.

TURN provided its own estimate of amounts of future recoverable costs for dry storage only by facility and asks the Commission to reduce the cost estimates by these amounts.

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65 TURN OB at 31.

66 *Id*. at 32.

67 TURN-23 at 13.

68 "Intergenerational inequity" refers to conditions that may arise when ratepayers who receive the benefits of a nuclear generating station, pay for the future decommissioning of the plant, which will not be completed until some decades in the future.

TURN's Estimate of Damages Associated
With Dry Fuel Storage During Decommissioning[69]

	Annual Dry Fuel Storage (100%)	# of Years from Start of Decommissioning until all SNF offsite	Conservative (low-end) Estimate of Total Damages (100%^)	CPUC Jurisdiction	Commission Share
Diablo Canyon	11.6	32	$371.2 million	100%	$371.2
SONGS	16.6	34	$564.4 million	96.3%	$543.5
Palo Verde	11.6	11	$127.6 million	15.8%	$202.5
Total					$934.9

All of the utilities dispute TURN's analysis, and ask the Commission to reject TURN's recommendation. SCE, SDG&E and PG&E argue that TURN's recommendation is based on the speculative assumption that "damage payments will be made" by the DOE to cover these costs.[70] However, SDG&E notes that courts have not always awarded utilities recovery of all the costs the utilities have incurred as a result of the government's breach.[71] For example, Edison was denied recovery of various costs associated with dry fuel storage, such as AFUDC, GTCC storage costs, and costs associated with Edison's efforts to establish a utility consortium to build and operate temporary storage facilities for spent nuclear fuel.

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[69] TURN-23 at 14, Table V-1.

[70] SCE RB at 9.

[71] SDG&E OB at 13.

Furthermore, PG&E adds that TURN's proposed significant reductions may wind up hurting ratepayers; the decrease would likely result in undercollections, which means ratepayers would forgo earning a rate of return on the uncollected amounts, resulting in greater required contributions later to make up for any shortfall.

4.1.4.3. Discussion

A utility's costs of cooling and storing spent fuel for an operating nuclear plant is generally paid for with general rates. After a nuclear power plant permanently shuts down (e.g., SONGS 1, HBPP) then costs of SNF cooling, storage, and disposal are included in decommissioning cost estimates and expected to be charged as a decommissioning activity, paid for with decommissioning trust funds, subject to recovery from DOE. To the extent the utility obtains compensation from DOE for such costs through periodic litigation, the net proceeds should be credited appropriately back to the source of the funds used for these activities.

TURN's hypothesis of assuming some or most future costs for SNF cooling will be compensated presents a balancing of interests. On the one hand, we only authorize collection of reasonable costs to prevent current overcollections; on the other hand, if significant costs are excluded from collection, future ratepayers may bear an unfair share of decommissioning costs.

It is not easy to create an intergenerational risk-proof decommissioning cost estimate when by nature the project will have unknown variables. Furthermore, TURN did not address utility claims of inconsistent or partial recoveries, or that DOE has allowed payment only for recorded costs. Even though TURN's proposal is limited to one category of potentially recoverable costs, the amounts utilized in its recommendation are still only high-level estimates. Moreover, funding for future DOE damage awards is still subject to future appropriations. Therefore, two of TURN's key supporting arguments are in question: certainty of payment and amounts of recovery.

The Commission is charged with ensuring sufficient (just not too much) funding to complete decommissioning, given the numerous uncertainties ahead. When it comes to nuclear decommissioning, both overcollection and undercollection are possible due to facts currently unknown. Nonetheless, we are committed to preventing intergenerational inequities whenever possible, particularly by our periodic review of the utility cost estimates to ensure they are modified as new site-specific or industry standard information becomes available.

For purposes of estimating decommissioning costs for the NDCTPs, the utilities shall disclose, in their next NDCTP application, all settlements, awards, or other resolution of damage claims completed in the triennial period, based on DOE failure to accept SNF. The utilities shall also establish how the recoveries were allocated to ensure that NDTFs received the appropriate share of net proceeds commensurate with payment of the underlying costs supporting the resolved claims.

Although TURN raises a serious point regarding potential overcollections, there is insufficient information to establish a substantial likelihood of recovery, and in what ratio of claims to recovered dollars. We do not share TURN's level of concern that the potential for inequity is so dire. The DOE litigation requires on-going utility claims in discrete time periods as costs are incurred. As subsequent claims are pursued, and paid, the results can be disclosed in the next triennial proceeding and tracked for applicable credits to decommissioning costs.

Therefore, the Commission does not agree to delete costs for post-shutdown dry storage of spent fuel included in the utilities' cost estimates because the speculative proceeds of future litigation, incurred perhaps over decades, is not sufficiently supported to establish a substantial likelihood of recovery and amounts.

4.1.5. Contingency Factor of 25%

In the 2006 NDCTP, the Commission ordered SCE, SDG&E, and PG&E to serve testimony in the next NDCTP to demonstrate they have made "all reasonable efforts to conservatively establish an appropriate contingency factor for inclusion in decommissioning revenue requirements."[72] The utilities collaborated to develop a common assumption for contingency factors, and incorporated them in the 2009 NDCTP showing. The assumptions included the use of a 25% contingency for all SONGS, Diablo Canyon, and Palo Verde nuclear generating units in 2009. The Commission's decision in the 2009 NDCTP included finding the use of 25% contingencies at each of the facilities to be reasonable estimates.[73]

In these consolidated 2012 NDCTP proceeding, all three utilities again included a 25% contingency in their cost estimates. By contingency, the utilities mean "performance contingency."[74] ORA disputes the automatic application of the contingency factor approved in a prior proceeding, and specifically opposes

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72 SCE-08 at 5 (citing D.07-01-003).

73 D.10-07-047 at 54, 56.

74 PG&E-18 at 2-22 (refers to "performance contingency" the utilities mean costs that are historically inevitable over the duration of the job of this magnitude).

the 25% for Palo Verde which we discuss separately below.[75] SCE rejects ORA's allegations as "flawed."[76] On the other hand, CDSO argued that because decommissioning costs are difficult to predict, the lack of a concise decommissioning plan, and almost no history in completing decommissioning, a 25% contingency assumed in prior NDCTP proceedings "may be quite insufficient."

The Commission finds that 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.

In these proceedings, we discuss the contingency factor within the context of the individual plants. However, the utilities have established that 25% may be reasonable for SONGS 2 and 3, DCPP, and PV, as projected in the prior NDCTP, because (at the time of testimony) Phase I activities had not yet commenced, and the utilities had not undertaken the more detailed site-specific cost analysis necessary for commencing Phase I of decommissioning and to better identify and limit unknowns.

4.1.6. Advice Letters (AL)

In a related matter, during 2013 and 2014, SCE and SDG&E have submitted several ALs to the Commission in which the utility seeks approval to withdraw funds from their respective SONGS 2 and 3 NDTFs to support planned decommissioning activities. Some of the ALs have included a request to approve

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[75] ORA-2 at 24.

[76] SCE-8 at 1.

trust funds for employee severance costs and other decommissioning-related costs. The ALs are contested and under review by the Energy Division.

One such AL, filed by SCE, was for interim disbursements of up to $214 million from the SONGS master trust for units 2 and 3 to cover 2013 decommissioning expenditures.[77] SCE also wanted authority for a Tier 2 advice letter procedure to govern future trust disbursements and any Commission review of decommissioning activities. CDSO made one of several protests of AL-2968-E, and tried to bring the dispute into these proceedings to halt approval of withdrawals from the SONGS trust funds.

CDSO argued that when the Commission created the AL process for PG&E and the HBPP decommissioning, we expressly deferred application of the process to SONGS until the Commission had time to "evaluate" the process.[78] CDSO takes the position that no such evaluation occurred, therefore, no AL process is appropriate for access to NDTFs, or for post expenditure reasonableness reviews can be approved here.[79]

Action on this AL is outside the scope of these proceedings. However, CDSO is mistaken that we have not reviewed the HBPP process of AL review. In Section 8 of this decision, we address that evaluation which occurred in Phase 1. In the 2009 NDCTP decision, the Commission observed the difficulties of tracking decommissioning costs from conceptual cost estimates to the more detailed site-specific cost estimates developed as decommissioning gets underway. Nonetheless, we required a reduced level of difficulty in referencing

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77 On November 18, 2013, SCE filed Advice Letter 2968-E.

78 CDSO OB at 14-15.

79 *Id*. at 11.

costs back to the most previous cost estimate, and a cost category from an approved AL as factors in evaluating the reasonableness of requests to withdraw trust funds.[80]

In Phase 1, the Commission took testimony and evaluated the effectiveness of the AL process for PG&E regarding HBPP decommissioning. We found that in order to discharge our responsibilities to undertake the triennial review of decommissioning expenditures, and interim oversight of decommissioning activities between triennials, the reporting and approval process needed some modifications.

We adopt for SCE and SDG&E, in connection with future decommissioning activities at SONGS, the same process as set forth in the Phase 1 decision applicable to PG&E.[81] This process includes, but is not limited to the following:

- The Utilities jointly or separately shall provide references for claimed costs to the most recent decommissioning cost estimate approved by the Commission;
- The Utilities shall work with Energy Division to develop a spreadsheet for requesting disbursements that contains specified information;
- The submission shall include a comparison of actual cash flow to its most recently approved estimated cash flow schedule; and
- The Utilities are required to maintain a written record of key decisions about cost, scope, or timing of a major project or activity (i.e. varies by +/- 10%), including the nature of

80 D.14-02-024 at 49.

81 *Id.* at 49-52.

> the decision, who made it, factors considered, and whether and what alternatives were considered.

These process elements may be blended into the common summary and data presentation recommendations by TURN in § 5.17 and for SONGS decommissioning oversight approved in § 7.1.3.1 which each require a post-decision meeting for the parties to discuss matters of improving transparency of utility decommissioning cost estimates through completion of decommissioning activities.

Energy Division has temporarily suspended its review of the ALs regarding SONGS 2 and 3 decommissioning. In this decision, we approve a decommissioning cost estimate (Early Shutdown) for SONGS 2 and 3. This estimate is appropriate for comparison to recorded 2013 and 2014 post-shut down decommissioning expenses in connection with a reasonableness review.

Energy Division may refer such ALs for consolidation in the proceeding commenced to review SCE's 2014 estimated site-specific decommissioning cost estimate and plan.

4.1.7. NDCTP Data Presentation

TURN offered three suggestions to alter the NDCTP applications which TURN contends would significantly improve the transparency of the NDCTP applications, and to expedite the review by the Commission, intervenors, and the public.

TURN states it is not proposing that all assumptions between SONGS and DCPP must be common, only that they be transparently explained. TURN offers three suggestions relating to the presentation of data in the next NDCTPs. The changes are intended to build on the common summary format and to facilitate comparisons both within and between utility submissions.[82] The three are as follows:

1. Cost Estimate Summary - SCE and PG&E should provide a site specific cost summary that includes a comparison between the current submission and the estimate from the two previous NDCTPs. TURN expects the utilities would organize and present the information to better highlight the phases of decommissioning to promote understanding of scope and cost.
2. Variance Analysis of Cost Estimate Summary- The utilities would use the Cost Estimate Summery to identify where to provide a variance analysis (at some fixed % change).
3. Common Summary Format – The utilities should enhance the Common Summary Format to include additional assumptions and allow for an explanation of key differences.

We appreciate TURN's attention to improving the transparency and utility of the decommissioning cost estimates. We agree the Common Summary Format, initiated by the Independent Panel, could be expanded to include a few more benchmarks for comparison, including explanations to account for significant differences in some cost categories. It would be useful to have significant changes from the most recent decommissioning cost estimate highlighted when reviewing the reasonableness of estimated or incurred costs.

Therefore, it is reasonable for SCE and SDG&E to initiate a meeting coordinated with Energy Division and other interested parties, within 60 days of the effective date of this decision, to develop a revised Common Summary

[82] TURN OB at 35.

Format to increase the amount of summary information available while preserving a brief and accessible document.

5. SONGS 1 Decommissioning Work and Cost Estimates

5.1. Completed Decommissioning Work Activities

In the Joint Application, SCE and SDG&E (Utilities) asked the Commission to find reasonable $14.9 million (100% share, 2011 dollars) in costs for SONGS Unit 1 (SONGS 1) Decommissioning Work completed between January 1, 2009 and December 31, 2012.[83] After hearings were concluded, SCE moved for admission of a late exhibit to "update" the total costs to $13.9 million.[84] SDG&E joins SCE in asking the Commission to find $13.9 million reasonable for the completed SONGS 1 Decommissioning Work.

The Commission finds that SCE did not meet its burden of proof to establish these costs were reasonable.

SCE's initial support for the claimed expenses consisted of a total cost and narrative description for two broad work categories: "Phase I Close-out and On-Going Decommissioning." SCE's testimony described how those costs were incurred by identifying and explaining the underlying activities and work.[85]

The Utilities' description of the two categories of expenses is as follows:

- Phase I Close-out Activities ($11.187 million): various activities occurred in 2009 related to completion of Phase I, including demobilize equipment and structures, perform radiological surveys of all equipment, tools, etc., return or salvage non-contaminated equipment and tools, packing and shipping contaminated materials, soil remediation,

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83 Joint Application of SCE and SDG&E for 2012 NDCTP (Joint Application) at 2.

84 SCE Motion to Late-File Exhibit SCE-20 (November 22, 2013).

85 SCE-2 at 9-11.

and installation of temporary utilities, structures, close-out of Phase I documents, development of Phase II and Phase III plans for future maintenance and decommissioning activities.[86]

- On-going Decommissioning Activities ($3.717 million): after the close-out activities, SCE incurred additional costs for SONGS 1 decommissioning during 2009-2012 including, ISFSI monitoring and maintenance, annual NRC fees, insurance and maintenance of the RPV package. SCE was also required to install 14 wells to monitor groundwater for tritium, as required by the Nuclear Energy Institute (NEI).[87]

5.1.1. Other Parties' Positions

TURN, ORA, and CDSO criticized SCE's lack of activity cost and contingency breakdowns, and argued there is insufficient information for the Commission to make its determination of reasonableness.[88] TURN further objected to the absence of the prior decommissioning cost estimate and the fact expenditures exceeded budgets. During discovery, SCE's response to an ORA data request highlighted a change in accounting systems: the database used for Phase 1 was closed out in 2008 when SCE adopted its current SAP system.[89] SCE did not create an on-going interface between the systems or, apparently, keep evidence of some requested SONGS 1 costs. The parties disagree over whether this is significant to the merits of whether the 2009-2012 costs were reasonable.[90]

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86 SCE-1 at 10-11.

87 *Id.* at 11.

88 TURN OB at 17; ORA-2 at 8-9; CDSO OB at 21.

89 Data Request DRA-SCE-008, Q1.

90 SCE-8 at 4.

ORA pressed for additional documentation for the close-out activities and costs.[91] In September, SCE provided a "2009-2012 Cost Report," a table listing activities, budget, recorded, difference, and a few words about some variances.[92] By its own admission, SCE's table identifies a combined "overage" of $4.27 million (28.7%) over budget, which SCE attributed to contingencies. However, SCE could not identify which expenditures exceeded their previous forecasts, due to reliance on limited budget information and extracted recorded costs through June 2008 to establish all claimed expenses.[93]

ORA continues to argue SCE did not meet its burden of proof because the company did not explain what data, assumptions, and/or methodologies it used to support the request.[94] Further, in a late-filed exhibit, SCE reduces the SONGS Unit 1's proposed decommissioning costs from $14.9 million to $13.9 million for the same activities.[95] The exhibit does not show what caused the reduction, how it was calculated, and why it is reasonable. In addition, ORA demonstrated that some categories of work changed location and amounts are revised in SCE-20 from SCE-15.[96]

On the other hand, SDG&E supports SCE's showing as sufficient to allow a comparison to a "reasonable range of prior estimates."[97] SDG&E reviewed, and

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91 SCE-15 at 1, ORA-SCE-009 Q5.

92 *Id.* at 3.

93 *Id*. at 1.

94 ORA OB at 4.

95 SCE-20.

96 ORA RB, Attachment 1.

97 SDG&E RB at 9.

did not dispute, any of the approximately $3 million of pro rata SONGS 1 decommissioning costs billed by SCE, finding them to be reasonable in amount and prudently incurred to meet the objectives of the SONGS 1 decommissioning project.[98] The Utilities assert that TURN, ORA, and CDSO presented no evidence to challenge the reasonableness of the described decommissioning activities and associated costs.

5.1.2. Discussion

The Utilities position assumes SCE made its prima facie case. However, TURN and SCE have different views as to the evidentiary showing necessary for the last review of completed decommissioning project costs. SCE mistakenly argues that, as a result of the 2009 GRC decision, the standard for reasonableness review of decommissioning costs was relaxed. "In D.10-07-047, the Commission decoupled the reasonableness review of actual decommissioning expenditures from the forecasted cost estimate."[99] SCE erroneously concluded it only needed to identify the actual costs and why they were incurred. This conclusion ignores that costs and the managerial decision to incur the costs must be reasonable.

TURN cautions that adopting SCE's interpretation would result in a "dramatic reduction in the scope of scrutiny applied to decommissioning expenditures.[100] We agree that SCE is mistaken in its interpretation of D.10-07-047.

In that decision, the Commission declined to extend to other Phases and other power plants, a presumption of reasonableness for SONGS 1 Phase I costs

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98 SDG&E OB at 5; *see* RT at 1138-1141.

99 SCE RB at 3.

100 TURN OB at 8.

(created by settlement) if they were less than the most previously adopted decommissioning cost estimate. Instead, we affirmed the importance of a more thorough factual review of recorded decommissioning expenses. The Commission said,

> At this time, we find that a full after-the -fact review of both costs and conduct best serves the interests of ratepayers and the public[101]…
>
> …More importantly, we find that the Commission's duty to review decommissioning activities to assure the costs were prudently incurred, in addition to being reasonable, is too significant to lump into a presumption solely based on costs.[102]

TURN and SDG&E ask the Commission to take this opportunity to clarify the appropriate reasonableness standard and the type of showing necessary for future reasonableness review of recorded decommissioning costs.[103]

We agree that SCE did not meet its burden of proof to establish SONGS 1 2009-2012 decommissioning expenses. Although we understand SCE's explanation of accounting system changes, this does not excuse the paucity of direct testimony, or absence of supporting documentation, calculations or linkage to previous expectations, until the rebuttal stage and hearing. SCE knew or should have known it would need to establish recorded costs for completed SONGS 1 decommissioning expenses subject to future reasonableness review. Instead, SCE concluded the Commission had eliminated a portion of our review in favor of a cost-only analysis. SCE chose to submit summary and insufficient

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101 D.10-07-047 at 44.

102 *Id.* at 48.

103 TURN OB at 19; SDG&E RB at 11-12.

evidence, and which exposed data omissions.[104] SCE's witness testified that because only limited information was available, it utilized its "budgeted" amounts as the benchmark to which overages were allocated.[105]

Most of the described activities are of the type we would expect to occur at SONGS 1, but a few words of narrative descriptions of activities, with aggregate total costs, are insufficient to meet SCE's burden. Some indication of whether recorded costs vary significantly from forecast costs, and why, are factors in the analysis of determining if actual costs were reasonably incurred.[106]

SCE eventually provided conflicting tables of activities and costs which might have been reconciled and included in the direct testimony, SCE attributed the difference to a transfer of DOE litigation proceeds.[107] Upon closer review, it is unclear whether any close-out activities (e.g., after June 2008) were estimated, or only the claimed Phase II on-going decommissioning activities.

We acknowledge that SDG&E's support for SCE's request, and acceptance of SONGS 1 costs billed by SCE, could support their reasonableness, depending

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[104] For example, for Phase 1 Close-out, SCE describes overages in four categories, all explained simply as a "carryover" from 2008. SCE does not explain why that increases the cost of "Utility Trench" by $1 million or "Overheads and Allocations" by $2.2 million more than SCE's budget.

[105] RT at 721.

[106] *See*, D.14-02-024 at 45-46, (In Phase I, PG&E's request for approval of costs for completed decommissioning projects was supported by a comparison of approved cost estimates ($26.649 million) and actual expenditures ($25.923 million) and explanations of differences that we found reasonable. PG&E did not fully comply with our expectations about interim tracking of decommissioning costs and activities. Although not ideal, we were able to correlate costs to filed Advice Letters and the latest approved decommissioning cost estimate).

[107] SCE-15 at 3, SCE-20 at 1.

on SDG&E's analysis. SDG&E claims its support is based on a wider scope of evidence, including reading of prior decommissioning cost estimates.[108] In addition, its witness testified at hearing as to the steps taken to verify the SONGS 1 activities, including observation and conversations with SCE and SDG&E personnel.[109] SDG&E offers its satisfaction with the brief descriptions of some variances in costs and its review of SCE's invoices for SDG&E's pro rata share.

However, we disagree that SCE adequately tied specific activity and cost information to the most recent previously approved cost estimate, or adequately explained and supported cost overruns. Furthermore, SDG&E's testimony supports only that some SONGS 1 decommissioning activities occurred, and that SDG&E was not alarmed by its pro rata cost bills. The Commission requires more accurate recorded costs and more fully explained variances in order to give final approval to these expenses.

Therefore, the Commission finds SCE did not establish the $13.9 million (100% share, 2011$) cost of SONGS Unit 1 decommissioning work completed between January 1, 2009 and December 31, 2012 is reasonable.

For Phase II Decommissioning, SCE recognizes the company will need a more functional cost accounting system going forward. SCE states it will develop a tracking model with functions similar to that used for SONGS 1 for the SONGS 2 and 3 decommissioning work. This issue is discussed further in § 6.1.3.3 below.

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[108] SDG&E-10.

[109] RT at 1141-1148.

5.2. Cost Estimate to Complete Decommissioning at SONGS 1

The Commission finds that SCE's decommissioning cost estimate of $182.3 million (2011$) for SONGS 1 is reasonable.[110]

Pursuant to an agency agreement approved by the Commission, Edison acts as the decommissioning agent for the SONGS 1 minority owners, including SDG&E.[111] The SONGS 1 decommissioning work consists of three phases. In Phase I, from July 1999 through December 2008, SCE decontaminated, dismantled, and disposed of most contaminated and non-contaminated SONGS 1 systems and structures.[112] During Phase II, commenced on January 1, 2009, SCE will dispose of its remaining SONGS 1 structures and materials, and monitor and provide security for the SONGS 1 spent nuclear fuel in the ISFSI.

Phase II will end after the DOE removes all SONGS 1 spent fuel from the site; estimated by SCE to occur by 2036 "based on studies developed from the Department of Energy."[113] One particular challenge is the disposal of the Reactor Pressure Vessel (RPV) which may need to be segmented for transportation and disposal. Phase III activities will occur concurrently with SONGS 2 and 3, including dismantling and disposal of ISFSI, submission of license termination plan, and completion of site restoration.

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110 SCE-1 at 17-22. Table IV-3.

111 SDG&E OB at 4.

112 SCE-1 at 12.

113 *Ibid.* (citing, *DOE Acceptance Priority Ranking & Annual Capacity Report).*

SCE internally developed an updated cost estimate for the remaining SONGS 1 decommissioning scope of work, as of January 1, 2013, based on the assumption of shutdown in 2022 upon expiration of their NRC operating license.[114] SCE provided a summary table of the estimates for remaining cost categories.[115] The "Base Case" cost estimate is $182.3 million (100% share, 2011$), and relies on several assumptions, including:

- an overall 25% contingency
- transfer of all SNF to DOE by 2036
- LLRW waste disposal costs updated to reflect approximate rates from Waste Control Specialists, LLC (WCS) which was recently permitted to accept Class B and C LLRW from states outside the Texas Compact.[116]

SCE presented evidence that specifically addressed its forecast for LLRW disposal costs, DOE removal, and the contingency factor. SCE provided explanations of the methodology and basis for the assumptions that are foundation of this cost estimate.[117] SCE also provided an estimated cost by work project, cash flow of remaining work, schedule for remaining work, and cash flow by cost category.[118] SDG&E found the estimate was consistent with

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114 SCE-1 at 2; SCE-1 Work Papers at 41 (*Cost Study for Remaining Decommissioning Work at SONGS 1* (SONGS 1 Cost Estimate) (December 2012)).

115 SCE-1 at 17, Table IV-3.

116 *Id*. at 14.

117 SCE-1 Work Papers (SONGS 1 Cost Estimate) at 45-55.

118 *Id.* at 57-63.

industry practice, regulatory requirements and information regarding the San Onofre site lease known to SDG&E.[119]

No party expressly opposed SCE's request. CDSO generally objected to use of a 25% contingency (in estimates for all nuclear units) which CDSO here suggests is so high it will encourage unnecessary spending to the maximum available, and implied the contingency must decrease "as plans become firmed up."[120] CDSO recommends the Commission direct SCE to determine contingency rates "based on unknowns which will decrease over time and as plans are refined."[121] However, the recommendation lacks legal or factual support, or even explanation except by reference to an Ohio state agency graph which purports to illustrate a contingency trend line during major transportation construction projects. CDSO's source material is not in the record, does not appear to be relevant, and is given no weight.

SCE testified its "contingency" is "a specific provision for unforeseeable elements of cost within the defined project scope" particularly where experience shows unforeseeable events with associated costs are likely to occur.[122] Furthermore, states SCE, the consensus in the industry literature is that an appropriate contingency factor for cost estimates at this stage of development

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[119] SDG&E OB at 8, fn. 27; (As directed in the 2009 NDCTP, the Utilities developed an alternate SONGS 1 cost estimate, based on NRC license renewal for SONGS 2 and 3, however, renewal is no longer an option).

[120] CDSO OB at 20.

[121] *Id.* at 21.

[122] SCE-01 at 14; See, American Association of Cost Engineers, *Project and Cost Engineers' Handbook*.

falls within a range of 15% to 30%, while NRC identifies 25% as appropriate for nuclear decommissioning cost estimates.[123]

SCE made a significant and detailed showing of its estimated decommissioning work activities and costs. No party disputed SCE's cost estimate[124] and the evidence presented conforms with our understanding of the necessary activities which will need to occur at SONGS 1, including the unknown extent of U.S. Navy-required remediation and future environmental requirements for final site restoration.

Therefore, based on the foregoing, the Commission finds that SCE has met its burden of proof in demonstrating that the SONG 1 decommissioning cost estimate of $182.3 million is reasonable.

The Utilities forecast that the $195.1 million ($2012) in SCE's SONGS 1 trust fund and $96.3 million (2012$) in the SDG&E SONGS 1 trust fund will be sufficient to meet the estimated SONGS 1 decommissioning costs. Therefore, the Utilities request no customer contributions for SONGS 1 decommissioning.

On a related matter, ORA argues the SONGS 1 trust fund is overfunded and recommends the Commission address disposition of the "surplus" $109 million in the next NDCTP.[125] ORA's advice is supported by a simple comparison of the October 31, 2012 liquidation value of the trust funds and SCE's cost estimate in 2011$ to complete decommissioning.[126] SCE countered that the comparison is flawed because the analysis implicitly assumes all

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[123] *Id*. at 16.

[124] *See e.g.,* ORA-2 at 9 (ORA does not contest the cost estimate).

[125] ORA-2 at 10.

[126] DRA-2 at 4, 9.

decommissioning work will be completed in 2011. Instead, future decommissioning at SONGS 1 "will occur over the course of decades, and decommissioning is subject to unforeseen changes that may result from changes in decommissioning regulations and practice."[127]

ORA's suggestion is premature. We agree with SCE that it is prudent to keep the accumulated funds in the Qualified Trust to meet future uncertainties over the coming decades, and remind ORA these funds can only be spent on decommissioning of SONGS 1 without disqualifying the trust.

6. Decommissioning Cost Estimates for SONGS 2 and 3, and Palo Verde

SCE characterizes its decommissioning cost estimates submitted in the NDCTP as "conceptual," noting that no detailed engineering studies for work scopes have been done, no procurement activities have commenced and no contracts have been signed. For SONGS Units 2 and 3, SCE and SDG&E recently filed a Joint Application with the Commission a new, more site-specific decommissioning cost estimate and plan.[128] This 2014 plan reflects SCE's Post Shutdown Decommissioning Activities Report (PSDAR), which SCE is required to submit to the NRC within two years after a permanent shutdown.[129] The PSDAR describes a licensee's planned decommissioning activities, a timetable, and the associated financial requirements of the intended decommissioning program.

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127 SCE-07 at 4.

128 A.14-12-007 (filed December 8, 2014); SCE-6 at 1. .

129 10 CFR § 50.82.

SCE asserts its decommissioning strategies and assumptions are reasonable, valid, and supportable. Conversely, SCE argues intervenors' oversight recommendations are unreasonable, unnecessary, and unduly burdensome.[130] SDG&E supports SCE's positions.

On balance we find that the cost estimates proposed in the applications for each nuclear generating unit, although developed somewhat differently by the retained experts, are reasonable. We adopt these cost estimates subject to a few changes in assumptions as discussed below.

6.1. SONGS 2 and 3 Decommissioning Cost Estimates

After SCE announced on June 7, 2013 the early shutdown of SONGS Units 2 and 3, SCE was directed to submit an "early decommissioning" cost estimate to supplant its original (Base Case) estimate which assumed decommissioning would begin after license expiration in 2022.[131] The primary drivers of differences between the "Early Shutdown" estimate and SCE's Base Case estimate are: (1) the Early Shutdown estimate assumes decommissioning planning begins in mid-2013 and decommissioning work begins in mid-2015; and (2) avoided costs of fewer SNF assemblies generated are offset by costs to transfer all assemblies to dry casks and storage due to delayed acceptance by DOE.

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130 SCE-7 at 1.

131 SCE-6 at 1.

We review the Early Shutdown estimate of $4.132 billion as the most pertinent to our task in these proceedings.[132] This amount is approximately 1.3% higher than the previously approved 2009 decommissioning cost estimate.[133] SCE provided a reconciliation table of the differences.[134]

The Early Shutdown estimated cost for Unit 2 is $1,972,565,000 (100% 2011$) and for Unit 3 is $2,159,777,000 (100% 2011$). The total site estimate is $4,132,342,000, approximately $14 million more than the Base Case, and $52 million more than the cost estimate approved by the Commission in the 2009 NDCTP.[135]

A description of the cost differences between the Base Case scenario and the Early Shutdown scenario is provided in the ABZ Cost Study and restated below.[136] The largest expense, according to SCE, is for spent fuel management due to lost economies of moving fuel directly to DOE from the SNF pool. Instead, SCE will have to move all SNF to dry storage and maintain storage until the casks are transferred to the DOE.

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132 SCE-6 at 4.

133 SCE-2 at 2 ($4.119 billion); SCE OB at 9.

134 SCE-6 at 5, Table II-I.

135 *Id*. at 4.

136 SCE-12 ABZ Early Shutdown Cost Estimate at 4.

In conformity with previously identified NRC regulations, the Utilities

Cost Category	Change (Early Shutdown/ Base Casein Thousands of 2011$)	Discussion
Elimination of WBS 0	($9,060)	The activities in WBS 0 for the Base Case are now assumed to be included in WBS 1.
Staff WBS 1-5	($37,698)	The difference in the timing of activities between the Base Case and the Early Shutdown Case changes the duration of several of the work breakdown structure (WBS) periods within decommissioning cost estimates for each case. The net effect of these schedule revisions is a $29 million (100% level, 2011 dollars) decrease in the Early Shutdown Case relative to the Base Case.
WBS 1-5 Period Dependent Costs	$14,005	Total effect of modified lengths of periods for WBS 2 thru WBS3.
Separation Payments	($25,111)	Difference between separation payments for 1675 in 2022 and 1470 for Early Shutdown
Fuel Management	$60,988	Includes cost for procurement of HSMs and canisters loading costs, ISFSI expansion and ISFSI demolition.
Additional Soil Fill and Excavation	$3,417	Added cost was due to change in scheduling that allows delay between work to minus three feet and remaining building removal below that level.
Allowances for Differences in Plant Initial Condition	$14,416	Added radioactive waste inventory and difference in tank and system status.
Change in Density for General Radioactive Waste Basic Task	($8,230)	Density of such waste changed from 100 pounds per cubic foot to 60 pounds per cubic foot
Correction of Error in DG Bldg Work and U3 LCR	$1,052	This is a correction of errors discovered in the process of adjusting the activities and schedule for the early shutdown scenario.
Total	$13,779	

project performance of SONGS 2 & 3 decommissioning activities in three phases, similar to SONGS 1.[137] The estimated costs to complete decommissioning of SONGS 2 and 3 were developed by ABZ, Inc. (ABZ) and employed the same methodology in both estimates. It is undisputed that ABZ is a recognized expert in nuclear decommissioning costs; ABZ used data SCE provided, and claimed to be based on SCE's experience with SONGS 1, which ABZ tested against ABZ's database of decommissioning costs at other nuclear sites.[138]

The Early Shutdown cost study provides both line item costs and aggregate costs separated into six basic categories, summarized in a schedule of estimated cash flows to complete decommissioning at SONGS 2 and 3: Labor, Staff, Materials, Burial, Energy, Separation Payments, and Other.[139]

SCE supported the Early Shutdown cost estimate with testimony about its decommissioning methodology, decommissioning cost estimating methodology, decommissioning schedules, and a reconciliation of the cost estimate to the Base Case, and initially reconciled the Base Case to the 2009 estimate found reasonable by the Commission.[140] SDG&E also conducted its own independent review of the Early Shutdown (and Base Case) cost study and found it to be consistent with industry practice and conventions, using reasonable assumptions and the best available information known to SDG&E.[141]

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137 SCE-2 at 3.

138 *Id.* at 4-5.

139 SCE-12 at 11 (Unit 2) and 285 (Unit 3).

140 SCE-6 at 5, Table II-1.

141 SDG&E OB at 8; Utilities-10 at 4;

Although SCE now requests no further contributions until the Commission reviews the Joint Application, SDG&E seeks approval to maintain the amount of previously approved contributions to its SONGS 2 and 3 nuclear decommissioning trust funds of $8.07 million.[142]

TURN, ORA and CDSO all expressed objections to the cost estimate by challenging one or more assumptions as unreasonable. Each provided recommendations to improve "oversight" of SCE's decommissioning process.

6.1.1. Assumptions

In its Early Shutdown cost estimates, SCE used most of the same major assumptions used in the cost estimate for the Base Case,[143] including:

- All below-grade foundations will be removed, along with intake and outfall conduits;[144]
- All concrete surfaces in rad-contaminated buildings are assumed to be scabbled[145] to an average depth of 0.5;"[146]
- Removal of hazardous waste to a licensed facility [SCE estimates more than four times the volume and three times the weight of Class A Bulk LLRW compared to DCPP];[147]
- Some fuel assemblies cannot be transferred from the SONGS 2 and 3 spent fuel pools to dry storage until 12 years after they are discharged from the reactor because

142 SDG&E Opening Comments at 3.

143 SCE-6 at 3-4.

144 Utils-11 at 1.

145 To "scabble" is to undertake a process for reducing contaminated concrete surfaces.

146 Utilities-11 at A-4 (historical contamination data has been used to estimate the amount to be assumed to be volumetrically contaminated with tritium and in need of LLRW).

147 *Id.* at A-8.

they require up to 12 years of thermal cooling before they can be placed in dry storage canisters;

- The DOE commences accepting SNF from industry in 2024 and from SCE for SONGS in 2027;[148]
- All other cost factors, such as labor rates, low-level radioactive waste shipping and disposal rates, and the 25% contingency factor remain unchanged; SCE's estimated SONGS craft/non-craft hours are about twice that at DCPP;[149]
- Utilized an LLRW burial escalation rate of 7.33%, higher than the 6.93% used in the approved 2009 NDCTP.

For purposes of the Early Shutdown case, SCE also used the new assumptions that SONGS 2 and 3: (1) will not generate additional spent fuel after January 2012; (2) permanently ceased operations and were placed in a SAFSTOR configuration by the end of 2014; and (3) decommissioning will commence by mid-year 2015.

6.1.2. Other Parties' Position

With the exceptions of the 12-year average thermal cooling period for SNF, none of the parties specifically challenge other assumptions made in the Early Shutdown cost study. However, TURN, ORA, and CDSO all asked the Commission to make changes to develop a better process for reviewing, monitoring and approving decommissioning expenditures.

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[148] SCE-6 at 3 (after taking the SONGS 1 fuel from the General Electric facility at Morris, IL, during 2024-2027).

[149] Utilities-11 at A-7, Tables comparing total estimated craft and non-craft labor hours by decommissioning phase.

6.1.2.1. ORA

ORA recommends the Commission deny approval of SCE's proposed SONGS 2 and 3 decommissioning cost estimates, but allow the Utilities to retain the current annual contributions of approximately $23 million.[150] ORA offered three recommendations:

- Deny approval of the proposed decommissioning cost estimates for SONGS 2 and 3 until a detailed site specific engineering and contingency study are completed;
- Stay a portion of this proceeding until an accurate estimate of decommissioning costs is developed;
- Require the Utilities to keep separate accounting and tracking of contingency, overages, and contractor costs; establish a permanent nuclear decommissioning data retention system to store and track costs for the project duration.

SCE and SDG&E have now filed the Joint Application for approval of the 2014 decommission plan and cost estimate for SONGS 2 and 3 that includes engineering and site-specific information, including line-by-line contingency studies. If the Commission subsequently adopts a 2014 cost estimate, ORA recommends the adopted 2014 cost estimate be used to determine both SCE's and SDG&E's contribution amounts for this triennial period.[151] ORA supports a stay of any estimate of cost and contributions, related to SONGS 2 and 3, until SCE's promised detailed site-specific engineering and decommissioning cost study, is performed and approved.

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[150] ORA-2 at 5.

[151] *Ibid*.

6.1.2.2. TURN

TURN characterizes its proposed revisions to the process for approval of the SONGS 2 and 3 decommissioning cost estimate as necessary to "improve oversight, increase transparency and provide meaningful accountability for SONGS 2 and 3 decommissioning."[152]

TURN's advice can be aligned into three basic recommendations regarding the SONGS 2 and 3 decommissioning cost estimates:

- Reduce the SONGS 2 and 3 total decommissioning cost estimates from $4,118.6 million to $3,554.2 million;[153]
- No authorization for any disbursements from the NDTFs until SCE has filed a detailed, site-specific decommissioning plan, including proposed major subprojects with milestones , budgets, and schedules for proper tracking, and agreed to accounting and decommissioning oversight; and
- SCE "proceed promptly" with decommissioning SONGS Units 2 and 3.[154]

TURN recommends the Commission reduce the combined SONGS 2 and 3 decommissioning cost estimate by $564.4 million (100%) resulting in a revised cost estimate of $3,554.2 million.[155] The reduction is estimated recoveries from future DOE litigation, based on TURN's legal analysis of the likelihood of recovery and the total estimated post-shutdown dry storage expenses through

[152] ORA OB at 3.

[153] *Ibid*.

[154] *Id*. at 23.

[155] *Id*. at 20.

2022.[156] TURN asks the Commission to disregard the Early Shutdown cost estimate in favor of the proposed 2014 detailed site-specific cost estimate, developed according to TURN's principles.[157]

TURN joins other parties in asking the Commission to order SCE to file the 2014 site-specific decommissioning cost estimate by a date certain. Furthermore, TURN recommends that SCE "proceed promptly" with decommissioning SONGS Units 2 and 3.[158] This urgency is supported by four factors, claims TURN: (1) using currently employed skilled employees; (2) current access to a class A and B radiological waste LLRW); (3) nuclear risk and liability reduction best achieved promptly; and (4) may provide negotiating advantage with U.S. Navy.[159]

TURN expressed dissatisfaction with its inability to compare previously estimated decommissioning costs with actual recorded costs provided for SONGS 1 and HBPP. Based on this experience, TURN offers recommendations to enhance review of utility decommissioning plans and costs.[160] In addition to directing SCE to file a revised plan and detailed cost estimate with the Commission, TURN recommends:

- Divide the entire decommissioning scope into 10-15 major subgroups each with distinctly defined budget, schedule, and completion milestones [TURN provided an illustrative list of subprojects that could apply to SONGS];

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156 *Id.* at 14, Table V-1.

157 TURN OB at 3.

158 TURN-23 at 23.

159 *Id.* at 23-24.

160 *See*, § 7.1.3.3.

- Commission should establish regular accounting oversight, perhaps an independent auditor, to ensure proper charging of actual expenses to the major subprojects; TURN's concern is to prevent utilities from unilaterally reclassifying expenditures and redefining the scope of work for individual projects without any notice to the Commission or parties;
- Commission should establish a Decommissioning Monitor to provide periodic reports to the Commission between NDCTPs to ensure regular awareness of SONGS decommissioning progress and issues; and
- Commission should require SCE to obtain approval from the Commission prior to filing any License Termination Plan with the NRC.

TURN claims these recommendations advance its interest in ensuring the Commission has appropriate opportunities to be involved where a utility is considering committing to new costs that reflect discretionary activities not explicitly required by other regulators.[161]

6.1.2.3. A4NR

A4NR stated it intervened in these proceedings in order to address the limited issue(s) of the reasonableness of the assumed timeframes for transfer of SNF from liquid pools to dry cask storage. Although SCE assumes a 12-year average for wet cooling of SNF, A4NR did not address the issue as to SONGS primarily because SCE has agreed to take steps to transfer SNF from wet to dry storage as soon as practicable in light of all constraints.   A4NR will revisit the matter in the new proceeding and in conjunction with SCE's NRC-required Integrated Fuel Management Plan (IFMP).

161 TURN OB at 21.

6.1.2.4. CDSO

CDSO provided comments and recommendations in the following areas: (1) cost estimates and TURN's related proposals; (2) insufficient oversight of SONGS 2 and 3 decommissioning; (3) SCE Advice Letter 2968-E related to the SONGS NDTFs; (4) changing NRC's defined stages of decommissioning; (5) the applicable contingency factor; and (6) ineligibility of severance costs for NDTF payment.[162] The latter two issues were discussed above. CDSO suggests the SONGS 2 and 3 contingency factor may be too low, but provided no evidence on the topic.

CDSO offers several "observations," primarily urging the Commission to direct SCE to provide what CDSO calls a "baseline" plan to be established now and be applicable as a benchmark for the entire decommissioning project.[163] CDSO supports TURN's proposal to prohibit the Utilities from obtaining any trust funds until a new detailed site-specific decommissioning cost estimate is approved by the Commission.[164]

CDSO challenges many of SCE's decommissioning assumptions and strategies, some of which are outside the scope of this proceeding, including several that are a matter of exclusive federal jurisdiction (e.g., assumptions about the spent fuel pool operations, SNF storage, and SNF disposal).[165] CDSO did not provide expert testimony in support of its SNF-related recommendations.

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162 CDSO OB at 2-3.

163 *Id.* at 10.

164 *Id.* at 9-10.

165 CDSO-20 at 12-16.

CDSO supports some of TURN's oversight recommendations (e.g., breakdown of decommissioning costs into smaller projects), and joined other parties in asking the Commission to order SCE to file its detailed site-specific 2014 decommissioning estimate for SONGS 2 and 3.

A prominent conclusion asserted by CDSO is that the Commission is not equipped to provide adequate oversight of the decommissioning of SONGS 2 and 3 without outside help.   CDSO's analysis derives from CDSO's view that the triennial proceedings are "too infrequent," and the AL process has too little information, "compares with the wrong cost estimates, and has insufficient opportunity for intervenor participation," to provide adequate oversight for the Commission.[166]

Therefore, CDSO (aka Citizens Oversight, Inc.) recommends the Commission establish a "Citizen's Oversight Panel" comprised of citizen volunteers to oversee SONGS decommissioning activities, spent fuel management, and even trust fund management.[167]   CDSO holds up the "California League of Bond Oversight Committees" and hospital district bond oversight committees as comparable models.[168]

CDSO also expressed concern that if SCE acts as its own general contractor in decommissioning SONGS 2 and 3, there is "an inherent conflict of interest, and

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166 CDSO OB at 12.

167 CDSO-20 at 11-12.

168 *Id.*at 9.

no cost benefit to ratepayers."[169] However, CDSO neither explained the projected conflict, nor provided any cost-benefit analysis with its testimony.[170]

SCE dispute's CDSO's statement because the decommissioning funds belong to its customers. SCE, therefore, "does not and cannot have a profit motive with regard to the use of those customer-owned funds."[171] We agree with SCE that it must return to customers unexpended decommissioning funds. It is also clear that a third party contractor takes a job to earn a profit, presenting other concerns.

CDSO did not support its statement and we are not persuaded of a predictable, imminent threat to customer funds. Instead, we observe there are risks and benefits related to prudent decisionmaking and cost controls with either the utility or a private contract manager for decommissioning.

The Commission acknowledges its important role to provide adequate oversight to ensure that SCE is making reasonable decisions for the use of ratepayer funds collected in the NDTFs. We expect that an improved, transparent accounting system (discussed below), with triggered reporting for significant changes, and robust review in subsequent triennial proceedings will be sufficient for the Commission to fulfill its responsibilities in this area.

6.1.3. Discussion

The SONGS decommissioning cost estimates have been consistently higher than DCPP and in comparison to other nuclear facilities, a fact which has been examined in prior NDCTPs, including by the Independent Panel appointed after

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169 *Id*. at 7.

170 *Ibid.*

171 SCE-8 at 23.

the 2009 NDCTP. The size of the SONGS estimate is largely accounted for by the site, explains TURN, particularly provisions of the Navy lease that may require removal of all improvements, including more than the industry standard of three feet below ground-level structures."[172]

We discuss below the issues raised by the parties.

6.1.3.1. SONGS Spent Fuel Management Issues

In Section 5.1.3 above, we found the 12-year wet cooling period reasonable as an average for 2012 NDCTP cost estimation purposes. However, SCE has indicated willingness to explore appropriate alternatives to reduce the wet cooling period for purposes of actual decommissioning practices.

SCE states it is working with Transnuclear[173] and the NRC to re-evaluate and possibly increase the heat loads that may be loaded into the 12 remaining canisters, and to license the design for 32 new canisters. According to SCE, if the new canisters are licensed, then it may be possible to reduce cooling periods.[174] We encourage SCE to continue its efforts to minimize costs of SNF cooling and storage within the confines of NRC regulations.

SCE is also developing its Integrated Fuel Management Plan (IFMP) that will include an analysis of the decay heat loads in every fuel assembly and other materials currently stored in the SNF pools. SCE disclosed that the anticipated IFMP will project more than five years for removal.[175] SCE is required to submit

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172 TURN-23 at 7.

173 Transnuclear developed the dry spent fuel storage system used at SONGS.

174 SCE-8 at 16.

175 *Id.* at 17.

its IFMP to the NRC with the PSDAR and the new site-specific decommissioning cost estimate.

CDSO raises other concerns and offers recommendations for the Commission to impose changes to SCE's current practices and assumptions regarding the use, cooling, packaging, and storage of nuclear material. Unfortunately, CDSO's decision not to respond to the seminal issue of federal pre-emption regarding SCE's spent fuel management decisions, impedes serious consideration of CDSO's ideas (*See*, Section 5.1.2.]

CDSO offered sometimes confusing and contradictory testimony about a number of aspects of spent fuel management. The testimony was primarily unsupported narrative, sometimes without a discernable position, and primarily concerning matters outside of the Commission's jurisdiction. (*See*, Section 5.1.2.]

We understand CDSO's views to include:

- a reasonable manager must assume that the SONGS fuel pool will be required during the time that the ISFSI is maintained on-site;[176]
- it would be prudent to assume the SONGS dry casks will be transported to an interim storage location until final repository is built;[177]
- the Utilities should be required to purchase a particular type of "dual-use" cask that CDSO states is suitable for storage and transport;[178] and

[176] CDSO-20 at 12.

[177] *Id*. at 13.

[178] *Id*. at 15.

- SCE should "engage with the NRC" to obtain a redefinition of the decommissioning phases so that Phases 1 and 3 can be completed before Phase 2.

Both SCE and SDG&E dismiss CDSO's recommendations related to SNF management as outside the scope of these proceedings, unclear, and difficult to reconcile with known facts and current regulatory obligations.

We agree that CDSO has expressed undeveloped ideas, and failed to address potential conflicts with existing law and jurisdiction. CDSO did not provide detailed explanation of the problems, alternatives and proposed solutions, any site-specific engineering or other technical support, a cost analysis, or a comparison timetable for these changes, particularly given the potential regulatory conflicts and other sources of delay.

In addition, CDSO described new proposed requirements on the Commission and SCE for the first time in post-hearing briefs (e.g., the Commission should ask the NRC to review and change their regulations regarding the order of decommissioning activities for license termination; and require SCE to address "high burn-up fuel" in its IFMP.)[179]

None of the intervenors directly addressed the state-federal jurisdictional separation set forth by the U.S. Supreme Court in *PG&E v. State Energy Resources Conservation and Development Commission*,[180] in the regulation of operations of a nuclear facility. Furthermore, no compelling economic argument was made to bootstrap the Commission's jurisdictional interest in the reasonableness of costs, into the solution of CDSO's proposals.

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179 CDSO OB at 18, 23-25.

180 461 U.S. 190.

The Commission is certainly aware of SCE's management and storage practices for spent fuel and other irradiated materials currently at SONGS. We take very seriously our responsibility to ensure the utilities have collected sufficient funding to undertake the reasonable and necessary steps and procedures to safely use, store, and dispose of hazardous material, given the evolving understanding by the industry of the best solutions and practices authorized by the NRC.

The Commission concludes that CDSO did not establish the reasonableness of its recommendations for operational changes regarding spent fuel in the decommissioning of SONGS. Consequently, we do not need to reach the question of whether CDSO is asking the Commission to adopt determinations that violate the exclusive jurisdiction of the NRC on matters related to nuclear safety.

6.1.3.2. Stay of Trust Fund Contributions and Withdrawals

TURN is very critical of SCE's Base Case and Early Shutdown decommissioning cost estimates because TURN was unable to track project expenses from the 2009 estimate to the 2012 estimates. TURN is supported by ORA and CDSO in its recommendation that the Commission not authorize release of any SONGS trust funds to SCE until the Commission approves a detailed site-specific decommissioning plan. TURN's proposal, includes proposed major sub-projects with milestones, budgets, and schedules for proper tracking, and agreement to accounting and decommissioning oversight by the Commission.[181]

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[181] TURN-23 at 27-28.

TURN's recommendation incorporates an assumption that the Commission will adopt TURN's proposals for a new and different scheme of oversight of SONGS decommission activities and costs, described in more detail below in Section 7.1.3.3. For example, TURN would extend the bar to prohibit SCE from making any decommissioning-related cost or schedule commitments to any other regulatory agencies prior to Commission approval of SCE's upcoming detailed, site-specific decommissioning plan and detailed cost estimate.

SCE contends TURN failed to justify any changes to the process, and argues the recommended changes are unnecessary and unreasonable.[182] SCE turns to its Commission-approved Master Trust Agreement (MTA) which SCE claims has already stablished an approval process for obtaining disbursements from the NDTFs.[183] Furthermore, SCE expresses concern that TURN's recommendations would unreasonably interfere with SCE's ability to comply with its regulatory requirements.[184]

We agree with SCE that a blanket prohibition on recovery of 2013 and 2014 decommissioning costs from the trust funds until certain oversight mechanisms are developed, is unnecessary and unreasonable. We also agree that TURN did not address facts particular to SONGS 2 and 3 disbursements, or provide evidence regarding specific deficiencies it suggests exist with the Commission's established oversight procedures. Furthermore, we are persuaded that TURN's

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182 SCE-8 at 11.

183 ¶¶ 1.01(9), 2.01 of the MTAs for SONGS 2 and 3.

184 SCE OB at 20.

proposal to prevent not only trust fund disbursements but regulatory filing to the NRC is deeply problematic for SCE.

TURN's proposals are especially puzzling when viewed next to TURN's recommendation that SCE "proceed promptly" with decommissioning SONGS 2 and 3. It is unclear how SCE can "proceed promptly" if there is no approved decommissioning estimate, no access to NDTFs to pay for decommissioning planning, and no interaction with regulatory agencies until we approve another cost-estimate, yet to be reviewed.

We agree with TURN that the Commission should generally be able, based on the Utilities' submissions, to compare estimated and recorded costs back to the most recently approved estimate with supporting evidence to explain significant differences. This is one factor in evaluating the reasonableness of a cost estimate.

SCE's compliance with the decommissioning cost-related reporting established in this decision should be sufficient to allay TURN's discomfort with the incompatibility of decommissioning cost studies when a power plant first transitions to active decommissioning. The type of activities in the early planning stages, such as those likely undertaken in 2013 and/or 2014, account for a relatively small part of the overall decommissioning costs, and we expect to see them in the Early Shutdown cost estimate.

Therefore, the Commission does not find it reasonable or necessary to impose a stay on SCE or SDG&E's ability to reach trust funds or to prohibit SCE from making any decommissioning-related cost or schedule commitments to any other regulatory agencies, prior to Commission review and approval of SCE's upcoming 2014 cost study.

6.1.3.3. Tracking of Cost Data and Improved Oversight of Decommissioning

The non-utility parties levied various criticisms of the utility decommissioning cost estimates and asked the Commission impose clear requirements on the Utilities to permit comparison of actual costs incurred to prior estimates. Furthermore, the parties seek a mechanism to provide more detailed information between triennial proceedings once a nuclear facility begins planning commencement of decommissioning activities. Both TURN and ORA stated similar goals to improve oversight, increase transparency, and provide meaningful accountability as decommissioning is undertaken.

6.1.3.3.1. Tracking Costs

As described above, TURN made specific recommendations it claims will improve our process for reviewing, monitoring and approving decommissioning expenditures. ORA similarly proposes requiring the Utilities to keep separate permanent accounting and tracking of contingency, overages, and contractor costs.

TURN's most substantial recommendation is that SCE should break the decommissioning plan into 10-15 major subprojects that include both period and activity dependent subprojects, each with a defined budget, schedule, and completion milestones suitable for tracking performance. This is similar to a TURN recommendation we adopted in Phase 1 for PG&E's large and costly Civil Works Phase at HBPP. In that decision, we agreed "there is value to the Commission and public in having a reasonably detailed cost breakdown of future decommissioning projects and a correlation to the previously approved cost estimate of activities, costs, and schedule."[185]

While arguing the various intervenor proposals are unnecessary, SCE concedes the importance of maintaining accurate records. SCE states it intends to develop and utilize a project controls system for SONGS 2 and 3 decommissioning that will "provide permanent accounting and tracking of contingency, overages, and contractor costs for greater transparency, accountability, and future forecasting studies.[186] However, SCE claims the project is currently in development, and SCE is unable to provide a data tracking framework at this time.[187]

SCE appears to understand what the parties want, and what the Commission needs, from the cost data presented before and after decommissioning commences. SCE asks the Commission to order it to present a framework for SONGS 2 and 3 and SONGS 1 that tracks actual expenditures by a limited set of cost categories, and provides a way to reflect the relationship of such cost categories both to the approved decommissioning cost estimate as well as to the updated decommissioning cost estimate that it presents for reasonableness review for SONGS 2 and 3 as well as SONGS 1.[188]

We appreciate SCE's request, and find it reasonable and appropriate to accelerate the process. When SCE presents its 2014 detailed site-specific decommissioning cost estimate for SONGS 2 and 3, SCE shall present a more

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185 D.14-02-024 at 50.

186 SCE-8 at 9.

187 SCE OB at 30.

188 *Ibid*. at 30.

concrete cost categorization structure for tracking expenditures. SCE shall identify ways to compare the decommissioning costs estimated to actual costs expended. The cost categorization shall reflect an approach similar to TURN's proposal to break the decommissioning plan into 10-15 major subprojects, each with an expected budget, schedule, and completion milestones suitable for tracking performance.

SCE and SDG&E have offered to work with stakeholders, including PG&E, the Energy Division, and the intervenors, to develop a cost tracking framework that will facilitate accurate and timely reviews of costs incurred during all phases of decommissioning of SONGS 1, 2, and 3.[189]

The Commission finds that transparent cost accounting and linkage to prior cost estimates, should enhance timely review and understanding of the basis for changes in scope or cost. There are benefits to both the public and the utilities where expectations of expenditures are known, the inevitable challenges and adjustments to plans are apparent and considered in near real-time, and when the utilities seek final approval for completed projects, there would be no surprises or lack of evidence supporting outcomes modified from early estimates.

The Commission finds it reasonable for SCE to organize a meeting, within 60 days of the date the decision is issued, to work with Energy Division, SDG&E, and other interested parties to ensure that SCE's cost tracking system appropriately facilitates tracking decommissioning expenditures by major

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189 SCE-8 at 9; RT at 1142-1143 (SDG&E is willing to work with SCE).

subprojects within a decommissioning phase, and allows for comparison to previously approved estimates of activities, costs, and schedule.

6.1.3.3.2. Decommissioning Oversight

Both TURN and CDSO take the position that the Commission is unable to handle oversight of decommissioning SONGS 2 and 3, and make specific recommendations to divert or delegate our statutory authority to do so. SCE responds that these recommendations, if adopted by the Commission, will add little, if any, value to the regulatory process that has already been established and will hinder the progress of decommissioning.[190] We reject these recommendations for the reasons stated below.

TURN recommends the Commission establish an independent auditor to prevent the Utilities from unilaterally reclassifying expenditures and redefining the scope of work for individual projects without any notice to the Commission or parties. In addition, TURN advises the Commission to engage a Decommissioning Monitor to provide periodic progress reports to the Commission on SONGS 2 and 3 decommissioning. However, TURN provided no evidence to support why such steps are necessary or why the Commission, itself, cannot perform such functions should it decide to do so.

SCE opposes TURN's recommendations for appointment of an independent accounting and/or decommissioning monitor on the grounds it is unnecessary and improper.[191] SCE argues the Commission has an established oversight framework for SONGS 2 and 3 disbursements and TURN has failed to

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[190] SCE RB at 14.

[191] SCE OB at 30.

provide any evidence to demonstrate why that framework is insufficient. Therefore, TURN's recommendations are misplaced.

We agree with SCE that TURN has not established a reasonable basis for these proposals. Similarly, we find that CDSO has not established a basis for its "Citizens Oversight Panel" (COP) conceived to provide oversight of everything from decommissioning plans, schedules, change orders, and expenditures to managing the NDTFs.

According to testimony, CDSO's objective is for the oversight body "to ensure prudent management of ratepayer funds" by undertaking its own "reasonableness review" of utility actions.[192] CDSO claims that the community advisory board (CAB) established for the Humboldt Bay Power Plant is "similar" to its proposed COP. However, this claim is mistaken. CDSO's proposal is for an "oversight" body with decision-making authority and management responsibilities. The CAB at HBPP, on the other hand, is advisory, not a decision-making body.[193] In its comments on the PD, CDSO offers a slimmer description of the proposed COP with no decision-making authority and management responsibilities, as opposed to some of the broader language in its testimony. Nonetheless, CDSO envisions a new level of citizen decommissioning review and oversight in some fashion which could filter Commission oversight.[194]

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192 CDSO-20 at 10-11.

193 SCE RB at 15 (CAB provides a forum for public input and communication between PG&E and the community).

194 CDSO Comments on PD at 1-2.

The Commission finds the COP would inappropriately usurp this Commission's authority to determine the manner of review and reasonableness of the costs of decommissioning activities.

Conclusion

Based on the foregoing we find that $4.132 billion is a reasonable cost estimate for purposes of this 2012 NDCTP. When adopted it may be used by the Commission as a point of comparison for SCE and SDG&E requests for preliminary approval of use of trust funds for reasonable decommissioning expenses at SONGS 2 and 3, incurred after June 7, 2013 through December 31, 2014.

SCE has filed its 2014 detailed site-specific decommissioning cost estimate, which reflects the PSDAR. SCE shall provide the filed IFMP in support of its application to this Commission for review of the 2014 revised and detailed cost estimate. Upon approval, the revised 2014 detailed cost estimate will be considered the most recently approved decommissioning cost estimate for SONGS 2 and 3.

As noted in § 1 above, both SCE and SDG&E have revised their requests regarding contributions for the SONGS 2 and 3 trust funds. The Commission found no evidence or argument has been offered to specifically address SDG&E's request to collect its increased contributions; thus no objection is anticipated to SDG&E or SDG&E collecting less in 2014 and 2015.

6.2. Palo Verde Decommissioning Cost Estimate

The Palo Verde Nuclear Facility consists of three Pressurized Water Reactors, Units 1, 2, and 3, operated by Arizona Public Service Company (APS). According to the NRC, the PV Units 1, 2, 3 each received license renewal in 2011 to operate through 2045, 2046, and 2047, respectively.[195]

SCE's 2012 Palo Verde Decommissioning cost estimate is $513.5 million (15.8% SCE Share, 2010$), a decrease of $173.5 million (25%) below SCE's 2009 cost estimate.[196] SCE developed its 2012 PV decommissioning cost estimate based on the most recent (2010) site-specific PV decommissioning cost study that was developed for APS by TLG Services, Inc. (TLG), a recognized industry expert.[197] SCE states it compared the major cost drivers in the TLG Study and the underlying assumptions to SCE's understanding of the factors that influence those cost drivers.[198] SCE also asserts its knowledge includes lessons learned during Phase I of the SONGS 1 decommissioning project.

Based on this analysis, SCE developed adjustments to the TLG Study that SCE alleges are consistent with SCE's decommissioning experience and knowledge of current factors that impact decommissioning costs. The result is a total adjustment of $138.1 million, increasing SCE's share of the PV decommissioning costs to $513.5 million, as illustrated below.

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195 http://www.nrc.gov/info-finder/reactor/palo1.html.

196 SCE-2 at 15, Table II-5.

197 SCE-16R (The TLG Study was developed in 2010 and was expressed in 2010 dollars).

198 SCE-2 at 15.

Comparison of SCE's Palo Verde Decommissioning Cost Estimates 2012 Cost Estimate vs. 2009 Cost Estimate[199]

Palo Verde Nuclear Generating Station	SCE Share, 2010$ x 1000
2010 Palo Verde TLG Study	375.4
SCE Adjustments:	
Class A LLRW Disposal Costs	90.5
Class B & C LLRW Disposal Costs	16.6
Spent Fuel Monitoring Costs	22.9
Contingency	26.1
TOTAL SCE Adjustments	156.1
2012 Palo Verde Decommissioning Cost Estimate	513.5

6.2.1. SCE's Adjustments to Palo Verde Cost Study

No party disputed SCE's adjustment related to Class A LLRW disposal costs which was based on SCE's experience with SONGS 1 underestimation of both the quantity of Class A LLRW and the full costs of disposal. SCE applied the adjustment factor of 64% developed by ABZ for use by SCE in adjusting disposal cost estimates for SONGS 2 and 3, reflecting SONGS 1 experience.

Similarly, there was no objection to SCE's adjustment for Class B and C LLRW. Disposal costs. SCE explained that because Palo Verde currently has no alternative but to ship its Class B & C waste to the WCS Texas facility, SCE made an adjustment to apply the WCS Texas rates to the projected volume of Palo Verde Class B & C LLRW.[200]

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199 SCE-2 at 16, Table II-6.

200 SCE-2 at 17.

The third undisputed adjustment is made based on the TLG assumption that the DOE will take over the Site Specific Part 72 License and be responsible for continued operation and maintenance of the ISFSI beginning in 2058 after plant decommissioning is completed.[201] Thus, the TLG Study does not include any funding for ISFSI monitoring and maintenance after 2057. SCE states it has no information that supports an assumption the DOE will assume all ISFSI costs completed from some date certain until it is eventually ready to remove the fuel to its permanent disposal facility. Therefore, SCE made an adjustment to provide for ISFSI monitoring and maintenance from the end of plant decommissioning until 2074, which is the year in which SCE projects that the DOE will remove the last fuel from the Palo Verde ISFSI.[202]

The Commission finds these three adjustments to be reasonable. The 2010 TLG Study for PV applied contingency factors ranging from 13.39% to 19.98% for various decommissioning activities.[203] SCE views the Commission's allowance of a 25% contingency in the 2009 NDCTP as approval for its use in subsequent proceedings. However, as we described in Section 5.1.5, the reasonableness of a contingency factor is significantly related to the stage of decommissioning and the activities projected, including particular site-specific challenges.

ORA disputed the basis for SCE's final adjustment related to the contingency factor applied to the cost estimate and asks the Commission to eliminate the $26.1 million adjustment.[204] ORA contends SCE has not done a

[201] SCE-2 at 18.

[202] SCE-2 at 18.

[203] *Id.* at 19.

[204] ORA-2 at 12.

specific study of PV to determine whether the 25% is relevant to its site-specific needs. Furthermore, argues ORA, adoption of the higher estimate by SCE places a disproportionate share of the costs on SCE's ratepayers.

We disagree. Although SCE did not provide specific evidence to support its determination that 25% is the appropriate factor, 25% is well within the industry range and the facility is licensed to operate for at least thirty more years, a factor for increasing contingency. Moreover, we are not persuaded that SCE's ratepayers are disadvantaged because the total recorded costs will be apportioned according to ownership interest.

7. Diablo Canyon Decommissioning Cost Estimate

PG&E's total cost estimate for decommissioning DCPP Units 1 and 2 is $2,786,073,000 (2011$). The total site estimate is approximately $957 million (52%) more than the approved 2009 NDCTP cost estimate of $1.828 billion (2008$). We reduce PG&E's requested increases to $459.11 million as explained below.

PG&E retained TLG to prepare cost estimates for the DCPP units under different decommissioning scenarios which included the same labor and LLRW burial rate assumptions and 25% contingency factor for the DECON[205] and SAFSTOR options. TLG has prepared the DCPP decommissioning cost estimates for PG&E since 1987. It is undisputed that TLG is a recognized expert in nuclear decommissioning costs.

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205 PG&E-19 at 2-11 (DECON assumes that any contaminated portion of a plant's systems, structures, and facilities are removed or decontaminated to levels that permit the site to be released for unrestricted use shortly after the plant ceases to operate).

At the Commission's request, PG&E developed three decommissioning scenarios for DCPP: DECON, SAFSTOR, and with a 20-year license extension. The total costs were similar; the SAFSTOR scenario resulted in an estimated reduction of $26 million, and under a license extension scenario, PG&E estimated spending $162 million less than if decommissioning commenced under DECON.[206] We reviewed the DECON estimate as the most applicable to the tasks in this proceeding. The DECON cost estimate assumes that PG&E will hire a Decommissioning Operations Contractor (DOC) to manage the decommissioning.[207]

PG&E supported its cost estimates with prepared testimony and work papers it claims fully document and support the assumptions used and the reasons for the changes which were identified. 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, which PG&E states it incorporated into the 2012 cost study for three cost categories: (1) Security; (2) severance costs; and (3) isolating the spent fuel pool and contaminated tools.[208] Another key change relates to the treatment of concrete within the reactor building which PG&E now assumes will be treated as potentially contaminated and removed.

As summarized below, PG&E asks the Commission to find that its cost estimate of $1.322 billion (2011$) to decommission DCPP 1 and $1.464 billion

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206 PG&E-24 work papers for chapter 2 (2012 Decommissioning Cost Analysis for DCPP at Executive Summary xvii).

207 PG&E-24 (DCPP Decommissioning Cost Estimate) at 16.

208 PG&E OB at 4.

(2011$) to decommission DCPP 2 is reasonable for the purposes of establishing the annual contributions to the ND Trust and the authorized revenue requirement in this NDCTP.

DECON COST SUMMARY
DECOMMISSIONING COST ELEMENTS
(thousands of 2011 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	17,296	20,420	37,715
Removal	129,569	283,111	412,680
Packaging	40,268	39,786	80,054
Transportation	18,060	17,954	36,014
Waste Disposal	175,448	171,400	346,848
Program Management [1]	315,334	368,348	683,682
Security	273,454	258,268	531,722
Spent Fuel Pool Isolation	24,045	15,996	40,041
Spent Fuel Management [2]	187,973	147,039	335,012
Insurance and Regulatory Fees	21,214	18,358	39,571
Energy	10,331	10,083	20,413
Characterization and Licensing Surveys	21,372	24,739	46,111
Property Taxes	5,987	5,825	11,812
Severance	74,269	74,113	148,382
Miscellaneous Equipment	7,849	8,167	16,016
Total [3]	1,322,468	1,463,605	2,786,073
Cost Element			
License Termination	999,926	1,036,573	2,036,499
Spent Fuel Management	248,912	207,854	456,766
Site Restoration	73,630	219,178	292,809
Total [3]	1,322,468	1,463,605	2,786,073

[1] Includes engineering costs
[2] Excludes program management costs (staffing) but includes costs for spent fuel loading/transfer/spent fuel pool O&M and EP fees
[3] Columns may not add due to rounding

Although PG&E states TURN is the only party which has opposed PG&E's DCPP cost estimate, ORA, CDSO and A4NR each opposed one or more of the common utility assumptions related to spent fuel as unnecessary or unsupported. The objections by CDSO and A4NR to assuming either an average 12-year SNF cooling period, or that 2024 is the date by which DOE will start to accept SNF, are discussed above and resolved in § 5.1.3.

7.1. Assumptions

In 2012, TLG generally applied the same methodology applied in 2009, with some exceptions. PG&E states the changes and assumptions made from the 2009 cost study integrated into the 2012 cost study include:[209]

- Use of the most current information by reflecting, (1) the general effects of inflation and cost escalation over the three years since the 2009 study was prepared, and (2) experience from fieldwork in decommissioning;
- Development of new cost projections for LLRW disposal rate:
    - Class A – costs from 2009 Joint Utility LLRW study, escalated to $2011;
    - Class B and C – based on blended rate for out-of-compact generators;
- Significant increase to the security work force to safeguard the spent fuel and facilities while spent fuel is wet up to 12 years;

[209] PG&E-23 at 2-4 to 2-6.

- All concrete within the reactor building steel liner is considered potentially contaminated and disposed of as LLRW;
- All demolished concrete will be transported and disposed of off and taken offsite; voids will be backfilled with clean off-site full;
- Contingency was estimated on a line item basis resulting in a composite contingency factor of 17.7% which PG&E modified to reflect an overall contingency of 25% pro-rated on a line-by-line basis;[210]
- The DOE commences accepting SNF from industry in 2024 and from PG&E for DCPP in 2033 with an average annual rate of transfer of 192 SNF assemblies;[211] and
- Estimated costs for ISFSI are included to accommodate SNF until off-site storage become available.

PG&E provided a table of the cost differences between the 2009 and the 2012 cost estimate.[212] Several of these changes are at issue.

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[210] *Id*. at 2-22.

[211] *Id.* at 2-9.

[212] *Id.* at 2-7.

PACIFIC GAS AND ELECTRIC COMPANY
DIABLO CANYON UNITS 1 AND 2
SUMMARY OF SIGNIFICANT CHANGES FROM 2009 TO 2012 DECOMMISSIONING ESTIMATES(a)

Line No.	Item/Activities Compared	2009 Estimate(b) (Costs in Thousands 2008 Dollars)	2012 Estimate(b) (Costs in Thousands 2011 Dollars)	Summary of Changes(c) (Thousands of Dollars)
1	Estimate Totals and Total Changes	1,828,346	2,786,073	957,727
2	Total Security (Wet Fuel)	122,947	446,363	323,417
3	Severance Related Costs	none included	148,382	148,382
4	Total Utility and DOC Costs Through Wet Storage	395,589	525,462	129,873
5	Total Nuclear Steam Supply System Removal (Including GTCC)	211,873	290,023	78,151
6	Total Reactor Building	42,123	115,952	73,830
7	Total Spent Fuel Canisters, Overpacks and Transfer	201,527	265,256	63,729
8	Total Miscellaneous Site Restoration Costs (Excluding Reactor Building)	113,356	175,544	62,188
9	Total Miscellaneous Transition Activities	18,951	49,318	30,367
10	Period-Dependent Through Wet Fuel Storage (Excluding Utility, DOC, Spent Capital and Transfer, Severance)	146,990	162,952	15,962
11	Total Security (Dry Fuel)	70,265	85,332	15,066

(a) Only cost drivers greater than $5 million are included.
(b) All estimated values included contingency such that overall contingency is 25 percent.
(c) 2009 estimate costs are reported in 2008 dollars; 2012 estimate costs are reported in 2011 dollars.

PG&E argues that TURN failed to provide any sound basis for its opposition to the higher cost estimates; instead charging that TURN seeks "solely to minimize the amounts to be contributed to PG&E's Nuclear Decommissioning Trust Funds (NDTF)."[213] The NDCTP is intended to ensure that the funds in the NDTFs are sufficient to cover the decommissioning of nuclear facilities at the expiration of their operational life. The adoption of any of TURN's suggestions,

213 PG&E OB at vi.

contends PG&E, would instead make it probable that the funds in the NDTFs would be insufficient, thereby requiring future customers to pay for these costs.[214]

Accordingly, PG&E proposed to file an advice letter in 2014 to update the annual decommissioning revenue requirement and contribution amount for Diablo Canyon based on the assumptions adopted in this NDCTP using fund balances as of December 31, 2013.

7.2. Other Parties' Positions

7.2.1. TURN

TURN rejects PG&E's 2012 cost estimate which includes a series of adjustments totaling nearly $1 billion, and cumulatively produces a 52% increase when compared to the DCPP decommissioning cost estimate adopted in the 2009 NDCTP. TURN rejects most of PG&E's proposed adjustments on the grounds that PG&E has failed to adequately justify or explain the drivers behind these substantial cost increases.

TURN instead asks the Commission to adopt an estimate of $2.066 billion (calculated by a simple 13% increase to the 2009 total cost estimate), plus make adjustments to (1) remove estimated dry fuel storage costs of $371.2 million; and (2) add $148.4 million for employee severance costs "if the Commission decides that such costs may legally be included in the estimate."[215] TURN's revised total for both adjustments is $1.843 billion, a net increase of $15 million, or less than one percent, since 2009.

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214 *Ibid.*

215 TURN OB at 3.

On the other hand, if we adopted the 2012 TLG cost estimate of $2.786 billion and removed the dry storage costs,[216] the adjusted cost estimate would be $2.415 billion (($2.786 - $0.3712 = $2.415 billion 2011$), approximately a 13.3% reduction to the 2012 base cost. TURN does not explain its addition of 13% to the 2009 estimate, although it may be intended as an escalation proxy.

In Section 5.1.1, we concluded state law permits utility recovery of <u>reasonable</u> employee assistance costs which may be considered decommissioning costs for utility employees who become unemployed due to the closure and decommissioning of a nuclear facility. The Commission provides direction to the utilities in Section 5.1.1 as to what sort of supporting documentation should be submitted for cost estimation purposes and with decommissioning AL process to show the reasonableness of such costs.

Furthermore, in Section 5.14, the Commission determined not to remove speculative costs associated with potential future recovery from DOE of certain post-shutdown dry storage costs included in the utilities' cost estimates. Additionally, we ordered the utilities to disclose, in their next NDCTP application, all settlements, awards, or other resolution of damage claims completed in the triennial period associated with DOE's failure to accept SNF for final disposal.

We also do not find a preponderance of evidence to support use of PG&E's 2009 study as the basis for cost changes, and to ignore the 2012 TLG cost study which purportedly incorporates field experience, site-specific information, and the general effects of inflation and cost escalation over the three years since the

[216] PG&E's cost estimate includes SNF dry storage costs and severance costs.

2009 study was prepared. TURN did not address these features of the 2012 cost study. Therefore, we find it reasonable to utilize the 2012 TLG decommissioning cost study as the basis for our review.

We now turn to TURN's recommended disallowances of PG&E's identified categories areas of significant increases. TURN points to PG&E's own testimony which cites eight factors resulting in changes, yet notes that only two[217] of these are found in PG&E's table of Significant Changes (reproduced above). As a result of data requests and testimony, TURN discovered information which it viewed as confirming that PG&E's estimated cost increases in several categories are not supported by evidence.

TURN asks the Commission to reject as unjustified the following identified increases to PG&E's 2012 cost categories:

- Nuclear Steam Supply System Removal (up $78.15 million, 36.9%) PG&E decided to send LLRW directly to disposal and eliminate the off-site waste processor which TURN states led to increases in estimated volumes of LLRW and associated transportation costs.[218] TURN states PG&E did not undertake accost/benefit analysis to determine whether elimination of an off-site processor would be economically advantageous.[219]

- Wet SNF Storage Security (up $323.4 million, 263%) PG&E supports the increase with site-specific security information developed by PG&E, and not reviewed by TLG for reasonableness. PG&E estimates both higher labor

[217] Security ($323.4 million) and severance ($148.4 million).

[218] RT at 983.

[219] TURN OB at 11; TURN-18 at 8.

hours and wages than SCE for SONGS without explanation.[220]

- Utility and DOC (up $129.8 million, +32.8%) PG&E does not explain the need for additional utility staff and contractor costs; the PG&E witness said PG&E's labor costs were the primary driver of change. TURN states the labor rates obtained from PG&E showed increases of 17.8% to 41.3% without justification or explanation of the overall increase.
- Total Reactor Building (up $73.8 million, +175.3%) PG&E claims the costs are driven by its decisions to directly dispose of SNF, and to "rip and ship" large structures, a method whereby all concrete is assumed to be contaminated. PG&E states it made the switch to the "rip and ship" mode based on industry experience at two nuclear plants more than a decade ago. TLG's witness claims the Panel recommended considering assumption made for SONGS, but then admitted SCE's cost study did not use the "rip and ship" method.[221]
- Total Miscellaneous Site Restoration costs (up $62.2 million, +54.9%) PG&E made no specific explanation but referred to extra costs to backfill excavated areas with clean fill, instead of uncontaminated concrete on-site.[222] TURN claims the assumed costs for the change to new backfill is about $40 million and that PG&E conducted no cost benefit analysis.[223]

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220 Utilities-11 at Appendix I-8.

221 RT at 991 (Witness Griffiths claims he referred to the lower assumed volumes of LLRW at SONGS).

222 PG&E-23 at 2 through 10.

223 TURN-18 at 10 (DR TURN-PG&E -010-Q14).

- Total Miscellaneous Transition Activities (up $30.4 million, 160%) PG&E provided no explanation for this change in its direct testimony; the TLG witness stated PG&E provided the higher costs related to the SNF pool and for contaminated tools, based on decade-old experiences at two other nuclear plants.[224] TURN observes PG&E did not explain why it waited to make the change until the 2012 NDCTP.
- Increased Unit Cost Factors Driven By Hidden Changes in Labor Costs PG&E projects an 18 -25% increase in unit cost factors used to estimate a variety of removal costs which impact several line item increases identified in the summary table above. TURN notes conflicting testimony about the driver of the increases: (1) PG&E's witness who said the overhead costs were not included in the 2009 cost estimate, and (2) TLG's witness who stated the labor rates in the 2009 cost estimate were represented as "fully burdened," and inclusive of overheads.[225]

Although TURN does not explicitly dissect the basis for its $2.066 billion base estimate, we observe that the total of these challenged costs, excluding unit cost factors, totals approximately $698 million, a $22 million difference between PG&E's estimate and the removal of the above-described increases.

7.2.2. ORA

ORA no longer opposes PG&E's proposed decommissioning cost estimates for DCPP. ORA does not dispute the 25% contingency factor, and has dropped its concerns with PG&E's estimated cost increases for DCPP decommissioning, in light of PG&E's agreement to use the most updated Trust Fund Balances when

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224 RT at 984-985.

225 RT at 1046 – 1047.

calculating the contributions for the NDTFs.[226] ORA opposed PG&E's initial decision that it was impractical to revise its HBPP Unit 3 revenue requirement. ORA asked the Commission to direct PG&E to update the revenue requirement for HBPP 3 in the same manner as PG&E had proposed for Diablo Canyon.

PG&E agreed to provide, through an AL filing, updated contributions and associated revenue requirements reflecting December 31, 2013 Trust balances for the Diablo Canyon and HBPP Unit 3 Trusts. No party has opposed this treatment.

7.2.3. A4NR

A4NR argues that PG&E has failed to meet its burden to prove the reasonableness of increasing the SNF-related portion of the DCPP decommissioning trust based upon a 12-year post-shutdown SNF wet storage assumption.

As discussed in §5.1.3, A4NR's sole focus is the reasonableness of the assumed timeframes for transfer of SNF from liquid pools to dry cask storage at DCPP and SONGS. Contrary to A4NR's recommendation, we conclude that the utilities' assumption of a 12-year cooling period for SNF from reactor to dry storage, is reasonable for the purpose of the high-level estimation of costs of decommissioning which occurs in the NDCTPs.

Within the same section, we also addressed A4NR's concerns that the utilities are not sufficiently responsive to an energy policy document (IEPR) bi-annually released by the CEC. We also observe that the recommendation, to reduce the time SNF remains in the fuel pools, may have either positive or negative economic effects, depending on other factors.

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226 ORA-3 at 7.

7.3. Discussion

What remains for discussion are the many objections by TURN. PG&E argues that TURN has not challenged any of PG&E's specific assumptions, and instead just rejects the entire analysis supporting the 2012 DCPP decommissioning cost study.

7.3.1. The Diablo Canyon Cost Study

We find that TLG followed a reasonable approach to developing its 2012 DCPP cost study, which then utilized several specific inputs from PG&E in key areas that resulted in significant cost increases.

TLG's methodology for its DCPP decommissioning cost estimate as in conformance with NRC and DOE guidelines.[227] TLG adopts the unit factor method, which TLG asserts "provides a demonstrable basis for establishing reliable cost estimates."[228] TLG utilized Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) developed using local labor rates. The activity-dependent costs are estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents.

TURN is focused on the substantial overall increase in the DCPP cost estimate and emphasizes that DCPP is conspicuous for the large increases during the last two NDCTP cycles, in comparison to SONGS and Palo Verde. The DCPP decommissioning cost estimate is now $1.2 billion more than the Palo Verde

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[227] PG&E-24 Work papers, TLG 2012 DCPP Cost Study" at ¶3.2 Methodology, citing AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"] and the DOE "Decommissioning Handbook."

[228] *Ibid.*

estimates.[229] 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 will look for evidence to support different assumptions.

TURN relied on the 2009 DCPP cost study 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 rejected the 2012 cost estimate and concluded that the DCPP cost estimate should "be limited to no more than 3% more than the SONGS increases."[230] TURN later revised its recommendation to no more than 13% more than SONGS.[231]

PG&E asks the Commission to reject TURN's "simplistic percentage increase" that provides no reason to believe the resulting estimate would in any way reflect the anticipated costs of decommissioning DCPP. TURN's recommended cap on the DCPP costs, argues PG&E, was made without any Diablo Canyon specific analysis, even though it altered the recommended increase from $54.8 million to $237.7 million.

We agree with PG&E that TURN did not establish it is reasonable to link growth of the DCPP decommissioning cost estimate to the estimate at SONGS. In each triennial proceeding, information about new technology, practices, and lessons learned emerge, as well as different thinking from each utility which identifies different approaches or inadvertently omitted activities. In the 2009 NDCTP, the Commission reviewed these differences and implemented

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[229] TURN-23 at 7-8.

[230] TURN-23 at 19.

[231] RT at 1278.

recommendations for uniformity in certain areas where reasonable. In this decision we determined there was insufficient evidence to support use of the 2009, instead of the 2012, cost estimate for DCPP.

TURN also rejects PG&E's reliance on the Independent Panel's recommendation to be more "conservative" to support increases.[232] TURN points out that the Panel's Report did not use the term "conservative." We observe that PG&E uses the term "conservative" in different contexts to support different approaches, but does not explain how the result is "conservative" in context. Therefore, we give it no weight.

TURN and PG&E also tangle over whether PG&E should or could calculate and disclose the cost impacts of proposed changes, given that the identified "significant changes" do not match up with the decommissioning "cost elements" provided by PG&E. PG&E responds that the "changes" table was not intended to isolate and quantify the impact of every single change in variables, but to summarize the impact of many inter-related cost estimate assumptions and inputs.[233] Instead it supports the 2012 DCPP Cost Study which uses a unit cost methodology to enable PG&E to determine a reasonable estimate of the cost to decommission DCPP.

Nonetheless, the Commission shares TURN's concern that the Commission and intervenors cannot see the calculations behind the large increases associated with the changes which ratepayers are asked to fund. TURN pressed PG&E's witness at hearing, who admitted the difficulty in determining the cost impacts

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[232] TURN OB at 9.

[233] PG&E-23 at 1-2.

associated with changed assumptions for economic and non-economic cost drivers.[234]

The decommissioning cost estimates are not meant to be the final decommissioning plans, and are developed as a sort of snapshot for the first step in determining ratepayer-funded utility contributions. We expect them to use unit cost factors and to be a high level estimate; we expect them to evolve over time. On the other hand, the Commission cannot exercise its reasonable review of the cost estimates if we are unable to penetrate the cost estimates through the triennial proceedings enough to see what changed and why.

In Section 5.1.7 above, we directed the utilities to coordinate with Energy Division and intervenors to develop a revised Common Summary Format to increase the amount of summary information available. This is a good opportunity for PG&E to work with Energy Division and interested intervenors to see how presentation of revised data in the 2015 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 cost estimate.

7.3.2. Security

The TLG cost study states Security is maintained close to operational levels while fuel is stored in the spent fuel pool. Security is reduced substantially once all spent fuel has been relocated to the ISFSI. PG&E estimated a $323.4 million (263%) increase for security costs related to the spent fuel pools, rising from $122.9 million in 2009 to $446.4 million in the 2012 cost estimate. Labor costs and

[234] TURN OB at 9; RT at 1008 -1010.

the period of time the spent fuel pools are in operation drive costs. The bulk of the estimated additional labor costs will be incurred between 2025 and 2037.[235]

PG&E attributes the increase to its compliance with a recommendation from the Independent Panel to utilize site-specific information. In direct testimony, the only explanation PG&E offered was that "the 2012 study considerably increased the security force to safeguard the spent fuel and associated facilities while the spent fuel is stored wet."[236] In rebuttal, PG&E stated the 2009 DCPP Cost Study security costs were based on a generic estimating model; the 2012 security cost estimate was based on a site-specific security model, with PG&E's security management providing substantial input.[237]

TURN observes that neither SONGS nor PV made similar large adjustments and argues that PG&E did not meet its burden of proof as to this increase. According to PG&E's expert,[238] the site-specific security cost data was developed by PG&E and," as a matter of standard TLG practice, was not reviewed for reasonableness."[239] The witness also indicated that he had never prepared a decommissioning study that involved an increase of this magnitude driven by security costs for wet fuel storage.[240]

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235 PG&E-24 (TLG 2012 DCPP Cost Study, Section 3 at 22-24, Table 3.1 (Schedule of Annual Costs).

236 PG&E-19 at 2-5.

237 PG&E-23 at 1-3.

238 PFG&E's expert is Geoffrey M. Griffiths, who developed the 2012 and prior decommissioning cost estimates for DCPP.

239 RT at 944.

240 RT at 943.

Proposing increases to security activities sounds comforting, but we wonder to what extent it is reasonable to rely on PG&E's security personnel to estimate future costs for themselves without review. Most of the security costs are labor, which reaches TURN's other concern about the significantly higher labor costs reflected in the DCPP estimate. TURN sees no justification for PG&E estimates of security labor costs of $64.34/hour while SCE estimates security labor costs of $41.82/hour.

TURN correctly claims the major discrepancy in total security hours and labor rates is not explained or addressed anywhere in PG&E's testimony or cost study.[241] The only reference we find in the record is the TLG cost study which states that labor costs for security personnel were provided by PG&E. Although the TLG cost study includes cost tables, the breakdowns of man hours & costs, by various stages of decommissioning, are not helpful in understanding the real cost impacts.

We previously determined that a 12-year cooling period for SNF is reasonable for the 2012 DCPP cost estimate, and it would be logical to assume some additional security personnel could be necessary for additional time related to use of the spent fuel pool. However, that's the extent of PG&E's evidence.

In comments on the PD, PG&E emphasizes witness testimony at hearing about internal discussions with the security team, the prohibitions against disclosure of security specifics, and the explanation that local labor costs are simpler higher at DCPP than at SONGS.[242] However, these comments somewhat

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[241] TURN OB at 12.

[242] PG&E Comments on PD at 3-5.

miss the point. Given the extraordinary increase requested, solely based on the 12-year wet cooling, PG&E could have provided some documentary evidence in support of its development of the estimate, the difference between the 2009 assumptions, and included source material for assumed security labor costs.

We are satisfied that both the 2009 and 2012 estimates included necessary non-labor costs, such as surveillance equipment, alarms, barriers, and emergency planning and safety training, etc. for the decommissioning period. The 2012 estimate seems to be primarily additional workforce estimated as needed between 2025 and 2037.

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, nor is it the last word on the subject.

Therefore, the Commission finds it reasonable to reduce PG&E' estimated security costs by two-thirds resulting in $107.7 million in extra security costs created by estimated longer maintenance of the spent fuel pools. DCPP is an operating facility and PG&E has the opportunity, should it choose, to return in 2015 to offer more evidence to support its estimates of necessary personnel to be used a decade ahead.

7.3.3. Removal of all Concrete "Rip and Ship"

TURN objects to PG&E's change in assumption of how to handle contamination in large concrete structures. Previously, PG&E has assumed it would identify contaminated concrete for LLRW disposal and use uncontaminated concrete for backfill, as PG&E did at HBPP3. In 2012, PG&E decided to assume that all concrete within the reactor building steel liner is contaminated and will be disposed of as LLRW (rip and ship). TLG incorporated the change in 2012 at PG&E's request.

The change is a "conservative" assumption, asserts PG&E, incorporated to ensure that the estimate included the cost of disposing potentially volumetrically contaminated concrete and eliminates the time spent to identify contaminated areas, decontaminating these areas, and resurveying them.[243] PG&E's expert asserted that removing demolished concrete from the site has a precedent from previous U.S. decommissioning experience, although he incorrectly identified SONGS as an example. PG&E claims it is responsive to reports from other sites (Maine Yankee and Connecticut Yankee) where operators found too much time was spent chasing cracks and decontaminating concrete, when simple removal and disposal as LLRW was easier to perform and certify.[244]

PG&E cannot directly determine the cost impact of this decision, but states it is part of an increase of $73.8 million to "Total Reactor Building." PG&E eventually provided an additional $40 million estimate to obtain clean backfill needed for the site under the category "Total Miscellaneous Site Restoration cost."

TURN faults PG&E for not conducting a cost-benefit analysis for this changed assumption. However, PG&E denies it can perform such a study because any such analysis would "necessarily rely on significant assumptions regarding the extent of concrete decontamination work required to release the facility.

243 PG&E-23 at 1-3.

244 TURN-18 at 10 (TURN-PG&E-010 Q12); *See*, PG&E OB at 4-5.

Although there are limits to performing a standard cost/benefit analysis for work to be done in the future under conditions unknown, we are not persuaded that PG&E conducted any analysis before deciding to alter its assumption to "rip and ship." There is evidence that two other nuclear facilities used the approach a decade ago, it might save time and money if the contamination exists in certain ways, and that it is likely easier for the project manager. But, this is a thin basis to make the change which results in higher estimated costs for ratepayers. PG&E overstates its efforts in reply, "PG&E has fully explained the reasons why previous assumptions regarding contaminated concrete are no longer warranted…."[245]

Therefore, the Commission finds it reasonable to reduce the cost estimate for DCPP by 50% of allocated Total Reactor Building increases, or $36.5 million, and an additional $40 million allocated to provide clean backfill which may not be necessary if PG&E decides not to follow through with its current assumption. Thus, the total reduction is $76.5 million.

7.3.4. Direct Disposal of LLRW and Related Issues

PG&E estimates an increase of $ $78.15 million increase (or 36.9%) relative to the 2009 estimate for the cost category "Nuclear Steam Supply Systems Removal."[246] PG&E explains this is based on a new assumption that all LLRW would be disposed of directly at the EnergySolutions facility; the off-site waste processors were deleted from the current study as no longer necessary.[247]

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245 PG&E RB at 9.

246 PG&E-19 at 2-7.

247 PG&E-19 at 2-6.

In support, PG&E's expert stated at hearing "…So it's a combination of industry experience and apparently the trend, at least in some site restoration activities." Another PG&E witness[248] said, "We don't believe that we could get a permit that would allow us to dump all this material [into the ocean].[249]

In response to TURN's challenge, PG&E's expert characterized the assumption as "conservative" because low-level waste processors may not be available at the time of decommissioning, and low-level waste processors are located in the eastern half of the U.S., which is likely to increase the cost of transporting waste.[250] The TLG study does not directly calculate the financial impact of this change because waste disposal is incorporated by individual cost line item.[251]

TURN argues PG&E did not meet its burden of proof as to the reasonableness of this assumption. First, the change resulted in higher costs and PG&E provided no analysis prior to making the decision. PG&E also did not explain the basis for reclassifying certain components as "clean" so they are removed from the LLRW calculations.[252] Furthermore, PG&E provides no discussion or explanation of why it determined these components are likely clean, and not in need of decontamination.

We are concerned that PG&E made only a nominal attempt to explain or justify changes in these and other assumptions which result in nearly one billion

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248 Loren Sharp, Project Manager for Decommissioning at HBPP3.

249 PG&E-RB at 10.

250 PG&E-23 at 1-5.

251 *Ibid.*

252 TURN-23 at 18.

extra dollars for ratepayers to pay over time to decommission DCPP. Although there may be merit, as TURN concedes, to consider direct shipment of LLRW without an off-site waste processor, PG&E does not make much of a case. It is insufficient, as PG&E's expert suggests, for the Commission or intervenors to simply compare aggregate waste disposal costs in the 2009 and 2012 cost estimates.

PG&E has failed to meet its burden to show that the $78.15 million increase is reasonable. PG&E has the opportunity in the next NDCTP to reconsider its assumptions and bolster them with calculations, successful examples of it working, or other information PG&E may choose to submit to establish the assumption is reasonable.

7.3.5. Utility and Decommissioning Operations Contractor (DOC)

PG&E projects a $129.8 million increase (or 32.8%) over 2009 for "Utility and DOC costs including Greater Than Class C (GTCC) waste."[253] PG&E describes the category as expected additional utility staff and contractor costs incurred for a variety of activities during the period of wet fuel storage (assumed to be 12 years). The item is listed in PG&E's table of significant changes, without further explanation in PG&E's direct testimony

TURN criticizes the increase as unsupported and we agree there is no explanation for this change in the 2012 study or direct testimony. Instead, during hearings, PG&E's expert stated the primary driver of this increase was higher hourly labor costs provided by PG&E.[254] TURN complains that it was

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[253] PG&E-19 at 2-7.

[254] RT at 966.

only through discovery was TURN able to determine that PG&E increased labor costs by 17.8-41.3% depending upon the category of work. PG&E submits the labor costs were increased to reflect actual labor rates. TURN then concludes the increase in labor costs is not adequately documented or justified.

We agree that PG&E's inclusion of a line item in a table is not sufficient to establish the reasonableness of PG&E's requested increase. It is unclear whether the increase includes any increase in expected GTCC, or if in fact the increase is all labor. PG&E also fails to explain why it will be adding personnel after permanent shutdown.

Therefore, we find it reasonable to disallow PG&E' estimated costs of $129.8 million for this cost category. PG&E did not meet its burden of proof to establish the amount is reasonable.

We share much of TURN's frustration with PG&E's attitude about how little it needs to say in order to establish a higher cost estimate and obtain almost $1 billion from ratepayer to increase the DCPP trust funds. Adequate funding is a very important goal which the Commission takes very seriously. However, it is not a basis for blank check funding of arbitrary or simply neglected proposed increases.

The Commission understands that decommissioning cost estimates are high level and are best estimates based on experience, known decommissioning activities, and known site specific information. We do not expect cost/benefit analyses on every method or approach included in a cost study. However, when a utility seeks large increases it should expect to provide more than an offhand sentence or two as the basis for costly changes. The Commission and intervenors should not have to engage in extensive discovery and cross-examination to ferret out scarce or absent reasoning behind assumptions or calculations with large effects.

Conclusion

The Commission finds it reasonable to reduce PG&E's 2012 Decommissioning cost estimate by a total of $497.89 million on the grounds the request lacked adequate support to demonstrate the requests were reasonable in nature and amount.

8. Compliance with Prior Commission Decisions

8.1. Compliance with D.10-07-047

In the 2009 NDCTP, based on representations by the utilities of interest in seeking license renewal, we ordered the utilities to include with their 2012 applications, contribution estimates that assumed successful completion of license renewal.[255] The utilities provided decommissioning cost estimates that assumed license renewal, however, intervening events render the exercise not useful at this time. (SONGS 2 and 3 are in shutdown and PG&E faces obstacles to obtaining a license renewal.)

In D.10-07-047, the Commission also ordered:

- The utilities to report the pro rata share of funds accumulated for NRC License termination and provide copies of their most recent funding assurance letters (pursuant to10 C.F.R. 50.75) sent to the NRC;[256] and
- PG&E to serve testimony in the 2012 NDCTP that demonstrates it has made all reasonable efforts to retain and utilize sufficient qualified and experienced personnel to effectively, safely, and efficiently pursue any physical

255 *Id.* at 61, OP 8.

256 *Id.* at 62, OP 9.

decommissioning related activities for the nuclear generation facilities under its control.[257]

We find that the utilities complied with these orders.

8.2. Compliance with D.11-07-003

As part of the 2009 NDCTP, the Commission approved the recommendations of the Independent Panel and ordered the three utilities to incorporate them into future nuclear decommissioning cost estimates submitted to the Commission.[258] The Commission ordered:

- the utilities shall agree on a common format to identify the key information from their nuclear decommissioning cost estimates and proposed revenue requirements as listed and provide it with each application in future NDCTPs;[259] and
- PG&E shall adhere to the Advice Letter Process set forth in the decision to notify the Commission of decommissioning activities, expenses, and trust fund reimbursements related to nuclear decommissioning of the Humboldt Bay nuclear power plant (HBPP3).[260]

We find that the utilities complied with the first order. According to TURN, the most visible sign of implementation was in the Common Summary Format for Decommissioning Cost Estimates. The Common Summary provided by the utilities in their applications expanded upon the suggestions made by the Independent Panel and showed effort for bridging the gap between the two different estimating formats used by PG&E and Edison.[261] We give significant

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[257] D.10-07-047 at 60, OP 4.

[258] D.11-07-003 at 41, OP 1.

[259] *Id*. at 42, OP 2, Attachment A.

[260] *Id.* at OP 3, Attachment B.

[261] TURN–23 at 4-5.

weight to TURN's appraisal, given their intervenor status as experienced experts and advocates for ratepayers. In particular, we note that one of TURN's decommissioning experts sat on the Independent Panel and was likely motivated to see the Utilities appropriately implement its recommendations.[262]

In our Phase 1 decision in these proceedings, we reviewed PG&E's compliance with the requested form and content of Advice Letters filed to keep the Commission informed about its HBPP3 decommissioning activities, incurred costs, and trust fund withdrawals related to HBPP3. In D.14-02-024, we found that PG&E did not fully comply with our expectations and order about interim tracking of decommissioning costs and activities, as set forth in D.11-07-003.[263]

After review of PG&E's incomplete efforts to effectively coordinate with the Energy Division its filing of the requested data and form for Advice Letters, we determined to make some modifications to the required reporting. We concluded the interests of ratepayers would be served if, in the future, PG&E (1) provided a reasonably detailed cost breakdown of completed decommissioning projects; and (2) maintained a written record of key decisions about the cost, scope or timing of a major project or activity.[264]

As a result of our evaluation, the Commission ordered PG&E to work with the Commission's Energy Division staff to develop a spreadsheet, including a number of major cost categories, for requesting decommissioning trust fund disbursements as required by D.10-07-047.[265] Furthermore, the Commission

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[262] Bruce Lacy.

[263] D.14-02-024 at 58, Finding of Fact 11.

[264] *Id*. at 60, COL 9.

[265] *Id*. at 40, OP 2.

ordered PG&E maintain a written record of key decisions about the cost, scope or timing of a major decommissioning project or activity at Humboldt Bay Power Plant Unit 3, *i.e.*, any decision that results in a variation from prior estimate by +/- 10%. At a minimum, the record shall include the nature of the decision, who made the decision, factors considered, and whether and what alternatives were considered.[266]

In the matter of HBPP3 decommissioning activities and costs, we are not waiting for PG&E to file ALs, or for the next NDCTP to assess PG&E's compliance with our orders. PG&E is well into decommissioning and currently undertaking several major civil work projects, some with unique challenges and/or substantial unexpected costs. Therefore, through our Energy Division, we are monitoring PG&E's expenditures to complete this important Phase 2 of decommissioning.

If the Energy Division finds that PG&E fails to provide required information, or appears to be at significant variance from the costs, scope, or schedule approved in D.14-02-024, the Energy Division Director shall inform the Commission's Executive Director for communication to all Commissioners of such findings in order to initiate further action, if necessary.

9. Rates of Return on Decommissioning Trust Funds and Trust Fund Contribution

Contributions by the Utilities 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

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[266] *Id.* at 61, OP 4.

order to help ensure the trust fund contributions will be sufficient to fully fund decommissioning of the nuclear plants.

As discussed previously, SCE has not requested contributions for SONGS 1 or Palo Verde, and has asked to limit its SONGS 2 and 3 contributions to the $5.681 million it contributed in 1Q2014. SDG&E considers its funding position to be distinct from that of SCE, but has now determined it need not increase its previously approved annual contributions of $8.07 million for 2014. SCE and SDG&E state they prefer the opportunity to revisit the SONGS 2 and 3 contribution levels after the Commission reviews their Joint Application to review the new PSDAR-related decommissioning cost estimate recently filed with the Commission.

PG&E's estimated total annual revenue requirement is $210.108 million:

- DCPP Decommissioning - $80.003 million
- HBPP Decommissioning - $120.100
- HBPP SAFSTOR - $10.005

PG&E explained that earnings and escalation assumptions are primarily relevant to determination of DCPP funding levels, because the HBPP3 Trust is being drawn down and decommissioning costs are being collected and paid out on a current basis.

TURN challenged several utility assumptions in connection with the conversion of the utilities' cost estimates into a revenue requirement. TURN recommended application of a higher (8.75%) return value as a reasonable pre-tax Return on Equity (ROE) for all the trust funds, and an increase from 2.90% to 4.25% for PG&E's estimated return on Fixed Income. TURN also asked for changes to modify investment management, particularly decreasing equity holdings to correspond with scheduled decommissioning activities. TURN's positions on these issues were opposed by all the utilities and primarily challenged as mistaken.

All of the utilities request the Commission adopt the proposed annual contributions which they similarly claim are supported by testimony and other evidence, and reflect "conservative" assumptions as to projected returns and escalation rates.

9.1. Trust Funds and Balances

Pursuant to the provisions of The California Nuclear Facility Decommissioning Act of 1985,[267] each utility was required to establish an externally managed, segregated fund and allowed to request sufficient revenues in rates to make the maximum contributions to the fund to recover the revenue requirements associated with reasonable and prudent decommissioning costs.

Each nuclear facility has established two master trusts to hold the decommissioning funds that result from all other contributions that qualify for an income tax deduction under Internal Revenue Code §468A. The utilities have established unit accounts within each trust. The MTA establish a Trust Fund Committee (TFC) to manage each utility's qualified and non-qualified trusts.[268]

The TFC consists of five members, at least three of whom may not be affiliated with the utility company and must be approved by the Commission. The TFC may appoint Investment Managers (IM), subject to Commission approval of the IMA. Each utility is required to provide an annual Trust Fund

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[267] Pub. Util. §§ 8321 et seq.

[268] Because of restrictions initially included in IRC § 468A, utilities wound up with "Non-Qualified" Trust Funds and "Qualified" Trust Funds, with different tax treatment. The Non-Qualified Funds have been significantly reduced.

report to the Commission, including specific information about IM performance and management fees and costs.

Below is a summary table of Qualified Trust Fund Balances for each utility and nuclear unit.

QUALIFIED TRUST BALANCES[269]

Dollars in millions	December 31, 2012
DCPP 1	919.785
DCPP 2	1,223.904
HBPP3	271.122
SCE SONGS 1	218.178
SCE SONGS 2 &3	2,902.751
SDG&E SONGS 1*	87.789
SDG&E SONGS 2 & 3 *	711.872
Dollars in millions	**December 31, 2012**

*The most recent trust fund balances for SDG&E in the record are from September 30, 2012.

The three utilities agreed with ORA's request that the final contribution amounts be calculated using the most recent Trust Fund balances. The term "most recent" is ambiguous, however, we understand it to mean December 31, 2013, the most recent year-end balances and appropriate for contributions in 2014.

9.1.1. Trust Fund Committees

During the 2009 NDCTP, the Commission examined a number of aspects of Trust Fund administration, including a review of the selection process for TFC members and IMs, individual fund performance, IM retention criteria, management and administrative costs, and the process for utility withdrawals of Trust Funds for payment of decommissioning expenses. We found no serious

[269] PG&E-23 at 5-4; SDG&E-7R; Joint Application at Appendix I-9; SDG&E SONGS estimates are from September 30, 2012.

problems, but adopted clarifications of various data and disclosure requirements.[270]

During hearings within the 2009 NDCTP, participants expressed concerns regarding inconsistencies and a lack of clear guidance about what information the utilities should routinely share with the non-utility TFC members, particularly as to planned decommissioning. The Commission ordered each utility shall ensure that Trust Fund Committee members timely receive the following information:

- Description of the selection process;
- *Audited financial statements for the decommissioning trust funds*;
- Initiation of Investment fund manager searches;
- *Decommissioning cost schedules, including acceleration or any other significant changes*;
- *Approval of nuclear facility license extension; and*
- *Withdrawals* of Trust Funds for decommissioning expenses [emphasis added].[271]

This baseline communication between the utility and the TFC members should be clearly established as the decommissioning of SONGS 2 and 3 is likely to commence in 2015, and PG&E's current licenses end in 2025. We re-emphasize the importance of SCE and SDG&E engaging the TFC members on a regular basis during Phases 1 and 2 when large expenditures occur and cash flows will increase substantially. We discuss the proposed equity ramp-down plans below.

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270 D.13-01-039 at 53-55.

271 *Id.* at 55, OP 13.

9.1.2. Tax Concerns

Internal Revenue Code Section 468A(b) states that the deductible "amount which a taxpayer may pay into the Fund for any taxable year shall not exceed the ruling amount applicable to such taxable year." To receive the "ruling amount," a taxpayer must file a request with the National Office of the Internal Revenue Service, and receive a "Schedule of Ruling Amounts (SRAs)," which stipulates allowable annual amounts that may be contributed and deducted for tax return purposes. Thus, it is important that the annual contribution amounts authorized by the Commission are equal to or less than the SRAs approved by IRS. Otherwise, any portion of the Commission-approved annual contribution amount that exceeds the IRS-approved SRAs cannot be contributed into the Qualified Trust nor deducted for tax return purposes.

All three utilities emphasize the importance of filing their request to obtain the Schedule beginning in 2014 with the IRS by March 15, 2015, based on contribution levels approved in this decision.[272]

9.2. Escalation Assumptions

In these proceedings, the utilities have calculated separate escalation rates for: (1) labor; (2) combined category of materials and equipment, (3) energy; and (4) LLRW burial.

SCE and SDG&E based their escalation projections for the categories of labor, energy, and Materials and Equipment upon projections by IHS Global Insight (IHS Global) economic forecasting service, which is undisputed as a reliable, independent, and accurate source for escalation and return forecasts.[273]

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[272] Utilities-10 at 10; PG&E-20 at 3-11; Treas. Reg. §1.468A-3€(1)(v) and Reg. §1.468A-2 (c)(1)..

[273] Utilities 10 at 12.

The IHS Global projection used 3Q12 and its long term forecast spans the period between 2012 and 2042.[274]

For each of the five main decommissioning cost categories, PG&E proposes to escalate costs to the period when decommissioning activities will be incurred using the escalation rates described below. Costs are escalated annually from the 2011 cost study period through 2056 when the last of the decommissioning costs are forecasted to be incurred.[275]

9.2.1. Labor

The three utilities all based their 2.77% labor escalation rates on IHS Global Insight projection of the Employment Cost Index for total compensation. The index is favored because it includes both direct compensation and the cost of employee benefits.[276] No party disputed the reasonableness of this assumption.

9.2.2. LLRW Burial Cost

To establish trends in burial cost escalation factors, SCE relied on historical trends in burial cost escalation factors published by the NRC to project LLRW burial cost escalation. SCE statistically estimated a 25-year range of annual burial cost escalation rates for three burial sites. According to SCE, the analysis produced five estimated escalation rates (ranging from a low of 0.2% to a high rate of 13.9%. The mean estimate was 7.3% and the median estimate was 8.4%. Consistent with SCE, PG&E proposes a 7.33 percent average escalation rate for LLRW burial costs.

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[274] *Ibid.*

[275] PG&E-20 at 3-5, Table 3-3.

[276] Utilities-10 at 7, Table I-1, 12.

ORA disputed application of the 7.33% escalation rate to HBPP3 because actual costs are known. PG&E has existing contracts with a disposal firm (WCS) for HBPP, inclusive of some packing, shipping and labor costs.[277] PG&E and ORA have stipulated that PG&E should adopt a weighted LLRW waste disposal escalation rate for HBPP Unit 3 based on contractual escalation rates and, for packing and shipping support, the PG&E labor rate escalation.[278]

9.2.3. Equipment, Materials, and Other

To escalate costs in this category, SCE and SDG&E constructed an Index the utilities claim is a weighted average of other material-specific price indexes, the utilities also constructed an econometric model to estimate a 30-year projection.[279] SCE and SDG&E's resulting escalation rate is 1.89%.

PG&E proposes to escalate equipment and materials costs based on a weighting of two indices: (1) for consumable materials comprising 88%, the forecasted changes in the GDP from Global Insight; and (2) for heavy duty equipment comprising 12%, the forecasted changes in the producer's price index for machinery and equipment from Bureau of Labor Statistics Series WPU112.[280] PG&E's resulting escalation rate is 1.59%.

No party disputed the reasonableness of these assumptions.

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277 PG&E OB at 14.

278 *Ibid*.

279 Utilities-10 at 7, 13.

280 PG&E-20 at 3-6.

9.2.4. Energy Other

To escalate costs for the energy category, SCE used the IHS Global Insight projection of the cost of retail industrial electricity in the "Southern Pacific" region of the United States to develop its escalation factor.[281] PG&E did not provide separate information about this category, but proposes using an escalation rate for "other" costs based on the forecasted changes in the **GDP** price index from Global Insight. No party disputed the reasonableness of this assumption.

Based on the foregoing we find that the proposed escalation rates by SCE, DG&E, and PG&E are reasonable.

9.3. Forecast Rates of Return

Each utility developed its own forecast for rates of return on the equities and fixed income portions of its trust funds for the qualified and non-qualified trusts. The parties had different views about what benchmarks to use and how to interpret them. Consequently, the divergent assumptions about the trust fund portfolios and management contributed to differing results. Although asset allocations will vary some over time, SCE and PG&E reported having approximately 60% equities and 40% fixed income investments in their Qualified Trust Funds.[282]

SDG&E "modeled its liability for decommissioning costs using the schedule of activities and costs shown in the Early Shutdown Study."[283] SDG&E

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[281] *Ibid.*

[282] Utilities-3R at 17; PG&E-20 at 3-9.

[283] SDG&E OB at 17.

claims it then determined the reasonable level of annual contributions necessary to assure that the trusts will have sufficient funds to meet those liabilities.

TURN's expert argues the utilities return assumptions are flawed and offered what he viewed as reasonable evidence to support a higher number for both equities and fixed income investment.

Below is a summary of the Utilities' assumptions, and TURN's recommendations, regarding future performance of the NDTFs.[284]

Requested Asset Returns Pre and Post Tax

Source	**Equity Return (%)**		**Fixed Income Return (%)**	
	Pre Tax	After Tax	Pre Tax	After Tax
SCE	7.79	6.36	4.27	3.42
SDG&E	7.48	5.84	4.25	3.16
PG&E	7.50	6.60	2.90	2.20
TURN	8.75 for all utilities		4.25 for PG&E only	

The Commission's adopted rates of return should advance the goal of sufficient funds to support the costs of reasonable and prudent decommissioning activities without imposing an unreasonable burden on ratepayers.

9.3.1. Return on Equity

The utilities each assert their estimated return on equity, though not all developed the same way, is reasonable, consistent with the Commission's objectives, supported by evidence from reliable long-term capital market forecasts and, therefore, should be adopted.

SCE based its projections of future trust returns upon projections provided by capital market sources and IHS Global Insight. For the equity return forecast, relevant through 2024, SCE used long-term capital market asset

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284 Utilities-11 at Appendix I-9.

class return assumptions from five financial institutions, including Russell Investments, Blackrock, and Aon Hewitt. SCE states the equity return forecasts ranged from 7.30% (Russell Investments) to 8.78% (JP Morgan), with an average investment firms' capital market pre-tax return of 7.79% for equities. SCE adopted the average of 7.79%.[285]

SDG&E's forecast of 7.48% for equity returns was computed by weighting ten-year forward market forecasts from four well-known financial institutions.[286]

SDG&E assumed SCE would bill SDG&E for a ratable twenty-percent (20%) share of SONGS 2&3 decommissioning costs. PG&E's return for equity of 7.50% is based on published, long-term equity forecasts of Russell Investment Group (Russell) as of June 2012.[287]

9.3.1.1. TURN's Position

TURN's analysis began with reference to the fact that actual returns have exceeded adopted forecasts based on an overall portfolio return. TURN broadly argues that the utilities' projections rely on long-run average assumptions "provided by third-party sources that consider broad asset classes …. in many cases are based on asset descriptions that do not exactly match" the actual portfolio of equity investments currently held or expected to be held by the trusts.[288]

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285 Utilities 10 at 16.

286 Utilities-11 at I-9; corrected at RT at 1172; PG&E-23 at 4-1, 4-3.

287 PG&E OB at 15.

288 TURN OB at 38.

TURN's expert, Garrick Jones, faults the utilities' equity return assumptions drawn from generally accepted professional sources because the estimates "contradict information from other sources regarding the future return investors generally expect."[289] In testimony, TURN made three basic arguments to challenge the utility assumptions, and support a higher return on equity for all three utilities. TURN claims the utilities estimated returns were derived from the wrong sources, are lower than other equity return estimates the utilities have made in other proceeding and contexts (i.e., utility pension funds and Cost of Capital), and that TURN's imputed risk premium demonstrates higher equity returns are appropriate.

TURN provided other examples of "aggressive" equity returns from the utilities' Cost of Capital proceedings wherein proposed equity returns ranged from 10& to 11.1%; in further extrapolation,[290] TURN calculated its proposed 8.75% return on equity by averaging its own calculations of (1) SCE/SDG&E average constant risk premium equity return assumptions (8.97%); (2) average equity return expected from California utilities' pension funds (8.17%); and (3) average equity return expected from TURN's data from national utility pension funds (9.15%).[291]

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[289] TURN-21 at 3.

[290] *Id*. at 3-4.

[291] *Id*. 21 at 7 (TURN based its analysis on numbers its expert culled from utility 10-K filings at the U.S. Securities and Exchange Commission).

Each of the utilities opposed TURN's testimony for similar reasons and contend each of TURN's arguments lack merit. They argue, for example, the pension fund equity return assumptions relied on by TURN were based on out of date or wrong data, and their current pension fund equity return is in line with SCE's and PG&E's contribution model assumption. Next, SCE asserts the other pension funds relied upon by TURN contain materially different and riskier assets which the NDTFs may not use. Lastly, SCE dismisses TURN's "imputed risk premium" as flawed and irrelevant for adjusting a contribution model's equity return assumption across economic cycles.[292]

We are persuaded that the utilities' return on equity assumption are reasonable and appropriate for the proceedings. TURN's arguments simply did withstand scrutiny.

Notably, in TURN's Opening Brief, the arguments regarding the return on equity rely on different grounds. TURN now faults SCE and SDG&E for "refusing to rely on international equity projections" when there is a minor presence of these assets.[293] PG&E's error, TURN now suggests, is that PG&E is thinking about changing its asset mix and should have considered different comparable funds. These arguments are speculative and lack merit.

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[292] SCE OB at 26.

[293] TURN OB at 39.

PG&E and SDG&E criticize TURN for seeking to compare pension fund returns to NDTFs, an argument the utilities claims was previously rejected by the Commission.[294] In D.07-12-049 (2006 Cost of Capital), the Commission rejected TURN's comparison of estimated returns for utility pension funds to ROE and concluded that, "Pension fund equity return assumptions are not comparable to the ROE used in utility ratemaking."[295] TURN does not view that conclusion as extending to NDTFs, and the decision does not expressly make that connection. In any event, we agree with the utilities that ND Trust funds have significantly different liabilities, investment restrictions, life spans, tax implications, investment objectives and risk tolerance than pension funds which affect asset allocations and expected returns.

The preponderance of evidence supports finding that the utilities each approached their analysis of the return on equity in a reasonable manner and, despite the differences in approach, reached similar results. The Commission finds the estimated rates of 7.79% for SCE, 7.48% for SDG&E, and 7.50% for PG&E to be reasonable.

9.3.2. Equity Glide Path

According to SDG&E, all three utilities have indicated that, over time, their ND trusts will make adjustments to the degree to which trust funds are allocated to different asset classes under measured "glide paths," primarily to reduce allocations to equities and correspondingly to increase allocations to fixed-

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294 PG&E OB at 20.

295 D.07-12-049 at 56, COL 31.

income securities.[296] These equity glide paths are planned to coincide with the schedules, progress and periodic cash requirements of the utilities' respective decommissioning projects.

SDG&E says it will implement a six-year scale-down out of equities beginning in 2014, versus the original eight-year scale-down beginning in 2017 in order to maintain a lower equity risk in the years decommissioning costs are being incurred and the years just prior to those spend dates. On the other hand, SCE will let its equity percentage fluctuate in order to accommodate SONGS 2 and 3 decommissioning schedules and expenditures.

PG&E, which has not yet performed a comprehensive allocation ramp down study, proposes a six-year ramp down after shut-down from 60% (the current allocation) to zero equities.[297]

TURN's expert instead suggests that SDG&E maintain a percentage of the trust assets in equities throughout the majority of the decommissioning period. SDG&E replies that asset allocation strategy is primarily the responsibility of the TFC. TURN also suggested that SDG&E adopt a "hypothetical" fixed-income tax rate of 20%. We agree with SDG&E on two points: (1) the recommendations are undeveloped, unsupported, and likely to lead to risks for ratepayers; and (2) trust fund management is the responsibility of the TFC.

TURN made other suggestions regarding returns on investment and asset allocation which we do not address because they lack any record support. The posture of TURN's expert has been to advance a number of positions which have in common, at first blush, only the possibility of lower rates in the short term.

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296 SDG&E OB at 28.

But there is no evidence the ideas have been thought through and the long and short term consequences well considered. ND Trust Funds are a unique creations in operation and purpose, which makes their management responsive to additional concerns and factors for reasonableness.

We do not adopt TURN's proposals to affect the operations of the trust funds because there is insufficient evidence to suggest adoption would meet the goals and purpose of the NDTFs. The trust funds are externally managed for several reasons, one of which is to take long, careful thought before any undue risk to ratepayers' funds. Another interest is to respond to changing facts of decommissioning including early decommissioning.

9.3.3. Return on Fixed Income

SDG&E states it calculated its forecast of 4.25% for fixed-income returns by weighting forecasts for ten- and twenty-year core fixed income securities, AAA-rated corporate bonds, and U.S. Treasury bonds provided by the same four financial institutions. SDG&E believes these return assumptions are reasonable and reflect an appropriate level of conservatism given the trusts' purposes and the low interest-rate environment and market uncertainties that currently exist.[298]

To reach its of 4.27% fixed income return forecast, relevant through 2055, SCE chose to use long-term capital market fixed income returns for the ten-year period 2013-2022, and IHS Global Insight Long Term Macro forecasts for fixed income beyond 10 years. PG&E assumed its 2.90% rate of return for fixed income based on information published by Russell.[299] As explained by PG&E

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297 PG&E RB at 19.

298 SDG&E OB at 19.

299 PG&E OB at 21 (TURN-19 at Bates 4-5).

witness Huntley, PG&E developed returns based on an expectation of Federal treasury yields having duration comparable to that currently maintained by the ND Trust.

As with equity returns, the utilities all ask the Commission to find the assumptions reasonable.

TURN recommends the Commission adopt SDG&E's 4.25% for all three utilities, particularly to "bring [PG&E] in line with" SDG&E's pre-tax assumptions which TURN finds more "realistic."[300] For example, TURN points out the 20-year federal historical bond rate is 5.22% and the rate averaged 3.57% in the twenty days ending September 17, 2013. SCE and SDG&E, states TURN, have made more reasonable estimates based on the average annual return realized for 20-year bonds since 1993 (5.22%).[301]

We are persuaded that TURN did not demonstrate its recommendation is more reasonable based on PG&E's fixed income assets. PG&E explained in its brief why utilities might have different projections for returns on investments, and why TURN's reference to average historical returns may be unreliable. However, we are concerned that PG&E's estimated returns are significantly lower than the other utilities. PG&E should work with its Trust Fund Committee to endeavor to increase fixed income returns before the 2015 NDCTP.

The preponderance of evidence supports finding that the utilities each approached their analysis of the return on fixed income assets in a reasonable

300 TURN-21 at 7-8.

301 *Id.* at 8.

manner. The Commission finds the estimated rates of 4.27% for SCE, 4.25% for SDG&E, and 2.90% for PG&E to be reasonable.

9.4. Revenue Requirements and Trust Fund Contribution

The Commission requires the utilities to update the trust fund balances to December 31, 2013 when calculating their contributions. Each utility will submit an exhibit which describes the contributions and revenue requirements using the updated balances.

9.4.1. SCE

The SONGS Unit 1 and Palo Verde trust funds are adequately funded so that no contributions are required in this triennial period.

SCE originally sought an increase in total annual contributions for SONGS 2 and 3, but SCE now requests no additional contributions in 2014 and none in 2015, until the Commission has reviewed the new 2014 SONGS 2 and 3 decommissioning cost estimate related to SCE's PSDAR filed with the NRC.[302]

Based on the approved cost estimates for SONGS 2 and 3, SCE's revised contribution amounts and revenue requirements that result are just and reasonable.

9.4.2. SDG&E

SDG&E originally sought approval of an increase to its annual contributions to the SONGS Units 2 and 3 trust funds for its proportional share of the decommissioning expenses. SDG&E sought authorization to collect and contribute the full amount of its authorized annual contribution during 2014 pursuant to a one-time waiver of the limitation on debit entries to one-twelfth of

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[302] SCE Comments on PD at 12.

the authorized annual NDAM revenue requirement relating to trust contributions. However, in comments on the PD, SDG&E revised its request to instead maintain its previously approved contribution of $8.003 million in 2014, and no contribution in 2015, pending review of the new decommissioning cost estimate for SONGS.

Furthermore SDG&E seeks authority to amortize the 2014 forecasted Nuclear Decommissioning Adjustment Mechanism overcollection in rates for a 12-month period beginning January 1, 2015. We made no adjustments to SDG&E's cost contributions, escalation rates or rates of return, instead finding them reasonable.

Based on the foregoing, we find SDG&E's revised requested contribution amount for SONGS 2 and 3 and proposal to amortize the 2014 forecasted NDAM overcollections or undercollection in rates for a twelve month period to be just and reasonable.

9.4.3. PG&E

PG&E originally sought approval for $80.003 million in total annual revenue requirement for contributions to DCPP units 1 and 2. This would have been an increase of more than 800% over the revenue requirements approved in the 2009 DCTP. TURN opposed $957 million of forecast costs, which PG&E sought to add to its decommissioning cost estimate, on the grounds PG&E did not establish the necessity of the activities or the costs.

TURN sought reductions to PG&E's cost estimate for Diablo Canyon, but the actual adopted reduction to the cost estimate was $497.09 million. In this decision, we find it reasonable to reduce PG&E's forecasted decommissioning cost estimate by $497.89 million.

PG&E asks the Commission to authorize PG&E to collect an estimated annual revenue requirement for DCPP through the Nuclear Decommissioning Cost Charge in an amount to be adjusted through Advice Letter to reflect reductions adopted herein to the DCPP cost estimates.

In addition, PG&E asks the Commission to allow PG&E to collect an annual revenue requirement of $120.100 million for the Humboldt Unit 3 Nuclear Decommissioning Trusts. PG&E also requests the Commission find it reasonable to collect an annual revenue requirement for the Humboldt Unit 3 SAFSTOR expenses of approximately $10.005 million to be adjusted through Advice Letter to be recovered through NDAM.

PG&E sought approval of an annual contribution authorization to collect and contribute the full amount of its authorized annual contribution during 2014 pursuant to a one-time waiver of the limitation on debit entries to one-twelfth of the authorized annual NDAM revenue requirement relating to trust contributions.

Based on the foregoing, we find PG&E's adjusted contribution amount for DCPP Units 2 and 3 and proposal to amortize the 2014 forecasted NDAM undercollection in rates for a twelve month period to be 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.

10. Comments on Proposed Decision

The proposed decision of ALJ Darling 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 December 8, 2014 by SCE, SDG&E, CDSO, A4NR, PG&E and TURN. Reply comments were filed on December 15, 2014 by

SCE, SDG&E, A4NR, PG&E and TURN. To the extent that the comments merely reargued the parties' positions taken in briefs, those comments have not been given any weight. The comments that focused on factual, legal or technical errors have been considered, and, if appropriate, changes have been made. Furthermore, we have clarified certain party positions and removed confusing or redundant language.

SDG&E points out that the recent adoption of D.14-11-040 (SONGS Order Instituting Investigation) results in several near term deadlines for filing related Advice Letters which are similar to deadlines adopted herein, including submission of certain information with the recently filed Joint Application to approve new S ONGS decommissioning cost estimate. SDG&E requests that the Commission allow SCE and SDG&E to provide any items that a final decision requires with the Joint Application as supplemental testimony at a later date acceptable to the ALJ assigned to that proceeding. This is a reasonable request and we adopt it herein.

11. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Melanie M. Darling is the assigned ALJ in this proceeding.

Findings of Fact

1. PG&E filed A.12-12-012, its 2012 NDCTP on December 21, 2012. SCE, and SDG&E jointly filed A.12-12-013 for the 2009 NDCTP.

2. SCE and SDG&E own approximately 78% and 20% interests, respectively, in SONGS.[303] PG&E owns the DCPP Units 1 and 2, and the HBPPS Unit 3. SCE

[303] The City of Riverside holds the remaining ownership interest.

owns a 15.8% interest in Palo Verde Nuclear Generating Station Units 1, 2, and 3 located in Arizona.

3. Every nuclear power plant operator is required to enter a standard SNF disposal agreement with the DOE; these agreements provide that DOE will start accepting SNF starting January 31, 1998 to transport it to a permanent repository. No permanent U.S. repository has been established.

4. PG&E, SCE, and SDG&E assumed, for cost estimation purposes, that the DOE will begin to accept SNF for long-term storage in 2024; the record provides little or no support for any date other than 2024.

5. SCE, SDG&E, and PG&E, along with other nuclear plant operators, sued the DOE to recover costs incurred to store SNF 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. Not all SNF has the same heat load; the 12-year wet cooling period assumed by the utilities for the NDCTP, is allowed by their respective NRC licenses.

7. SCE, SDG&E, and PG&E each provided 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. All three utilities applied a 25% contingency to the decommissioning cost estimates submitted with their applications in these proceedings; by contingency, the utilities mean "performance contingency," *i.e.*, unknown but historically inevitable.

9. In Phase 1, we found that in order to discharge our responsibilities associated with the NDCTP, the reporting and approval process needed some modifications.

10. It would be useful to have significant changes from the most recent decommissioning cost estimate highlighted when reviewing the reasonableness of estimated or incurred costs.

11. SCE and SDG&E lack key information to estimate waste removal costs when making estimates of future costs for the SONGS units due to the ownership of the underlying land by the U.S. Department of the Navy which has not yet defined the standard to which the land must be returned at the time of license termination.

12. SCE and SDG&E asked the Commission to find reasonable $14.9 million (100% share, 2011$) in costs for SONGS 1 Decommissioning Work completed between January 1, 2009 and December 31, 2012. SCE revised the costs from $14.9 million to $13.9 million during the proceeding.

13. SCE and SDG&E submitted evidence to support their request for approval of the decommissioning cost estimate of $182.3 million (2011$) to complete decommissioning of SONGS 1.

14. The Early Shutdown cost estimates, submitted by SCE and SDG&E, estimated the cost for Unit 2 is $1,972,565,000 (100% 2011$) and for Unit 3 is $2,159,777,000 (100% 2011$). The total site estimate is $4,132,342,000, approximately $52 million more than the amount approved in 2009 NDCTP Case.

15. SCE asks for a Commission order to present a framework for SONGS 2 and 3 that tracks actual expenditures by a limited set of cost categories, and provides a way to reflect the relationship of such cost categories both to the

approved decommissioning cost estimate as well as to the updated decommissioning cost estimate.

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

17. SCE's 2012 Palo Verde Decommissioning cost estimate is $513.5 million (15.8% SCE Share, 2010$), a decrease of $173.5 million (25%) below SCE's 2009 cost estimate.

18. PG&E's total cost estimate for decommissioning DCPP Units 1 and 2 is $2,786,073,000 (2011$); the total estimate is approximately $957 million (52%) more than the approved 2009 NDCTP cost estimate.

19. SCE, SDG&E, and PG&E each submitted uncontested evidence that they had complied with orders from prior Commission decisions, including the ordering paragraphs 4, 8, and 9 of D.10-07-047 and the OPs 1, 2, and 3 of D.11-07-003.

20. Contributions by the Utilities to the NDTF are calculated by application of the rates of return to the approved and escalated cost estimates.

21. SCE has not requested contributions for SONGS 1 or Palo Verde, and has asked to maintain its current annual authorized contributions for SONGS 2 and 3 ($22.726 million) instead of increasing the annual contributions to $39.221 million based on its forecasts in this proceeding.

22. SDG&E considers its funding position to be distinct from that of SCE.

23. In its application, PG&E estimated its total annual revenue requirement to be $210.108 million comprised of $80.003 million for DCPP, and $120.100 million for HBPP decommissioning, and $10.005 million for SAFSTOR costs at HBPP.

24. Each nuclear facility has established two master trusts to hold the decommissioning funds; the trusts differ with respect to whether contributions to them qualify for an income tax deduction under Internal Revenue Code § 468A.

25. In these proceedings, the utilities have calculated separate escalation rates for: (1) labor; (2) combined category of materials and equipment, (3) energy; and (4) LLRW burial costs.

26. SCE, SDG&E, and PG&E provided evidence to support their common escalation rates for Labor, Materials and Equipment, and Energy; only the application of the 7.33% escalation rate for LLRW disposal costs was disputed.

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

28. Each utility developed its own forecast for rates of return on the equities and fixed income portions of its trust funds for the qualified and non-qualified trusts. The parties had different views about what benchmarks to use and how to interpret them.

29. The utilities each calculated their estimated return on equity, though not all developed the same way, and provided supporting evidence from reliable capital market forecasts: SCE assumed 7.79%, SDG&E assumed 7.48%, and PG&E assumed 7.50 %.

30. NDTFs are unique creations in operation and purpose, which makes their management responsive to some concerns and factors uncommon to other investment funds.

31. The utilities each calculated their estimated return on fixed income investments, though not all developed the same way, and provided supporting

evidence from reliable resources of: 4.27% for SCE, 4.25% for SDG&E, and 2.90% for PG&E.

32. PG&E is engaged in decommissioning of HBPP and use of the most recent trust fund balance will result in the most appropriate calculation of contributions.

33. To obtain a schedule of Rulings from the IRS, the utilities rely on Year End trust fund balances to calculate contribution levels which maximize tax benefit.

34. SCE submitted uncontested evidence that the SONGS 1 and Palo Verde trust funds have sufficient funds to complete decommissioning.

35. SCE originally sought approval for $39.662 million in total annual contributions for SONGS 2 and 3, but due to changed circumstances, SCE later determined that no additional contributions are necessary to fund the NDTFs until the Commission has reviewed the new 2014 SONGS 2 and 3 decommissioning cost estimate related to SCE's PSDAR filed with the NRC.

36. Due to changed circumstances, SDG&E revised its original requested annual contribution amount for SONGS 2 and 3, to instead continue collection of its previously authorized annual collection of $8.07 million, and to amortize the 2014 forecasted NDAM overcollection or undercollection in rates for a twelve month period.

37. PG&E originally sought approval for an estimated annual revenue requirement commencing of $80.003 million for DCPP units 1 and 2.

38. PG&E's requested contribution reflects an increase of more than 800% over the revenue requirement approved in the 2009 NDCTP.

39. PG&E originally sought approval for an estimated annual revenue requirement commencing January 1, 2014 of $120.1 million for HBPP.

40. PG&E's estimated decommissioning and SAFSTOR expenses were adopted in Phase 1 of this proceeding in D.14-02-024 at 59, OPs 4 and 6.

Conclusions of Law

1. The overall applicable standard of review for the numerous requests in the utilities' applications 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[304] 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 state concerns.

3. The California Nuclear Facility Decommissioning Act of 1985[305] 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. Pursuant to Sections 451, 8322(g) and 8330 of the Pub. Util. Code, reasonable employee assistance costs, for utility employees who become unemployed due to the closure and decommissioning of a nuclear facility, are

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304 42 U.S. Code § 2011 et seq.

305 Pub. Util. Code §8321 et seq.

considered decommissioning costs eligible for payment from Qualified nuclear decommissioning trust funds, provided payment does not jeopardize its "Qualified" status.

5. It is reasonable to assume for cost estimation purposes that DOE will not begin to accept SNF for long-term storage prior to 2024.

6. It is reasonable to assume for cost estimation purposes that some spent nuclear fuel assemblies will require 12 years of wet cooling. In the 2015 NDCTP, the Commission would benefit from each utility providing information comparing annual cost impacts of strategies to reduce wet cooling periods.

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

8. A nuclear plant licensee, such as SCE, is required to submit its spent fuel management plan to the NRC for review.

9. The record is insufficient for the Commission to conclude that future DOE damage awards are a predictable certainty which is sufficient to reduce the decommissioning cost estimates to reflect potential future damage awards.

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

11. SCE, SDG&E, and PG&E are in compliance with prior decisions applicable to decommissioning, including the OPs 4, 8, 9 of D.10-07-047 and the ordering paragraphs 1, 2, and 3 of D.11-07-003. Given PG&E's incomplete efforts to effectively coordinate with the Energy Division its filing of the requested data and form for Advice Letters, the Commission modified the required reporting in D.14-02-024.

12. Review of SCE's Advice Letter 2968 submitted to Energy Division for approval of interim disbursements from the SONGS NDTFs is outside the scope of these proceedings.

13. SCE and SDG&E, in connection with the decommissioning of SONGS, shall follow a similar process for providing continuity of cost tracking and documenting costs as set forth in the Phase 1 decision, D.14-02-024, applicable to PG&E.

14. The 2013 ABZ Early Shutdown decommissioning cost estimates approved for SONGS 2 and 3, are appropriate for use by Energy Division when reviewing ALs submitted for approval of interim disbursements from the SONGS NDTFs.

15. It is reasonable for SCE and SDG&E to initiate a meeting coordinated with Energy Division and other interested parties, to develop a revised Common Summary Format to increase the amount of summary information available while preserving a brief and accessible document.

16. SCE and SDG&E did not meet their burden of proof to establish $13.9 million of SONGS 1 decommissioning expenses incurred 2009-2012 are reasonable.

17. SCE decommissioning cost estimate for SONGS 1 of $182.3 million (100%, 2011$) is reasonable and should be adopted.

18. CDSO did not establish the reasonableness of its recommendations for operational changes regarding spent fuel in the decommissioning of SONGS.

19. It is neither reasonable nor necessary to impose a stay on SCE's or SDG&E's ability to reach trust funds or to prohibit SCE from making any decommissioning-related cost or schedule commitments to any other regulatory agencies, prior to Commission review and approval of SCE's upcoming 2014 cost study, providing all requirements for approval of the Advice Letter are met.

20. It is reasonable for SCE to develop 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.

21. CDSO did not establish a reasonable basis for the Commission to create a "Citizens Oversight Panel" (COP) to provide oversight of decommissioning plans, schedules, change orders, and expenditures, as well as managing the NDTFs.

22. As shown in its application, supporting testimony, and filings, SCE's and SDG&E's decommissioning cost estimate of $4.132 billion is reasonable for purposes of this 2012 NDCTP and should be adopted.

23. As shown in its application, supporting testimony, and filings SDG&E's ratable shares of the decommissioning costs for SONGS Units 2 and 3 of $36.46 million, $400.625 million, and $423.093 million, respectively, are reasonable.

24. As shown in its application, supporting testimony (including attachments to testimony), and filings, SCE's updated $513.5 million (SCE's share, 2010$) Palo Verde (PV) decommissioning cost estimate is reasonable and should be adopted.

25. It is reasonable to reduce PG&E's 2012 Decommissioning cost estimate for DCPP by a total of $497.89 million on the grounds the request lacked adequate support to demonstrate the requests were reasonable in nature and amount; the remainder of $2,286.713 million is a reasonable cost estimate and should be adopted.

26. PG&E's efforts, pursuant to D.11-07-003, to effectively coordinate with the Energy Division for filing of the requested data and form for Advice Letters were insufficient; this fact was addressed in the Phase 1 decision, D.14-02-024.

27. With the exception noted in conclusion 27, SCE, SDG&E, and PG&E each reasonably complied with orders from prior Commission decisions, including the ordering paragraphs 4, 8, and 9 of D.10-07-047 and the OPs 1, 2, and 3 of D.11-07-003.

28. It is not reasonable to apply the assumed 7.33% escalation rate for LLRW disposal costs at HBPP3 because actual costs are known.

29. The agreement between ORA and PG&E to apply a weighted LLRW waste disposal escalation rate for HBPP Unit 3 based on contractual escalation rates and, for packing and shipping support, the PG&E labor rate escalation is reasonable.

30. With the exception of the LLRW disposal escalation rate for HBPP, the escalation rates proposed by SCE, SDG&E, and PG&E for Labor, Materials and Equipment, and Energy are reasonable.

31. The utilities' assumptions for the return on equity for SCE of 7.79%, for SDG&E of 7.48%, and for PG&E 7.50 % are reasonable and should be adopted.

32. There is insufficient evidence to suggest adoption of TURN's proposals to compel certain asset allocation choices, which would significantly affect the operations of the trust funds, would meet the goal and purpose of the NDTFs.

33. The utilities' assumptions for the return on fixed income investments, estimated at rates of 4.27% for SCE, 4.25% for SDG&E, and 2.90% for PG&E, are reasonable.

34. 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, 2013 which should be used when calculating their contributions.

35. The SONGS Unit 1 and Palo Verde trust funds are adequately funded so that no contributions are required in this triennial period.

36. Based on the record, it is reasonable for SCE to stay collection of any increase to its annual contribution calculated in this proceeding for SONGS 2 and 3 and, because of changed circumstances since the application's filing, it is more reasonable for SCE to limit contributions in 2014 to those already made, and to collect no contributions in 2015, pending a final decision in the recently filed new decommissioning cost.

37. Based on the record herein, it is reasonable for SDG&E to make annual contributions up to $16.43 million to the SONGS Units 2 and 3 trust funds for its proportional share of the decommissioning expenses. However, because of changed circumstances since the application's filing, it is more reasonable for SDG&E to continue collecting its already authorized annual collection amount ($8.07 million) pending a final decision in the recently filed new decommissioning cost estimate.

38. It is reasonable for SDG&E to collect and contribute the full amount of its authorized annual contribution during 2014 pursuant to a one-time waiver of the limitation on debit entries to one-twelfth of the authorized annual NDAM revenue requirement relating to trust contributions. However, because of changed circumstances since the application's filing, it is more reasonable for SDG&E to continue collecting and contributing the already authorized annual NDAM revenue requirement related to trust fund contributions in one-twelfth increments in 2014.

39. It is reasonable for SDG&E to amortize the 2013 Nuclear Decommissioning Adjustment Mechanism overcollection or undercollection in rates for a twelve-month period beginning January 1, 2015, or the next rate implementation date.

40. It is reasonable to reduce PG&E's forecasted decommissioning cost estimate by $497.89 million due to lack of evidentiary support.

41. It is reasonable for PG&E to collect the full amount necessary to make annual contributions based on the escalation rates and rates of return found reasonable herein.

42. It is reasonable for PG&E to collect the full amount of its 2014 annual revenue requirement through Commission-adopted jurisdictional electric rates, pursuant to a one-time waiver of the limitation on debit entries to one-twelfth of the authorized annual NDAM revenue requirement relating to trust contributions.

43. It is reasonable for PG&E to collect through Commission-adopted jurisdictional electric rates for funding HBPP3 Safe Long-Term Storage (SAFSTOR) operation and maintenance, the annual revenue requirement, as updated in Phase 2, effective January 1, 2014: $10.005 million for 2014, $9.884 million for 2015, and $9.483 million for 2016, the actual revenue requirement to be adjusted to reflect the December 31, 2013 Trust Fund balances.

44. It is reasonable for PG&E to collect through Commission-adopted jurisdictional electric rates an annual revenue requirement for the HBPP NDTFs, effective January 1, 2014, the actual revenue requirement to be adjusted to reflect the HBPP decommissioning cost estimate as modified in D.14-02-024, and the actual December 31, 2013 Trust Fund balances.

45. It is reasonable for PG&E to continue revenue requirement associated with the ND trust contributions and HBPP SAFSTOR O&M through a non-bypassable charge as specified in Pub. Util. Code §379, and to continue to utilize the NDAM as authorized in D.99-10-057.

46. It is reasonable for PG&E to collect through Commission-adopted jurisdictional electric rates, an annual revenue requirement for the DCPP units 1 and 2 NDTFs, effective January 1, 2014, the actual revenue requirement to be adjusted to reflect the DCPP decommissioning cost estimate as modified herein, and actual December 31, 2013 Trust Fund balances

O R D E R

IT IS ORDERED that:

1. Within ten (10) days of the effective date of this Decision, Southern California Edison Company (SCE) shall file a compliance advice letter 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. To the extent SCE has withdrawn San Onofre Nuclear Generating Station Unit 1 decommissioning costs not allowed in this decision ($13.9 million) SCE shall promptly return the funds to the non-Qualified Nuclear Decommissioning Trust Fund, with interest. The compliance advice letter shall be served on the service list for the consolidated proceedings and shall describe how SCE will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2013 nuclear decommissioning trust fund balances. The updated

information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2014 and 2015. 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 advice letter.

2. Within ten (10) days of the effective date of this Decision, San Diego Gas & Electric Company (SDG&E) shall file a compliance advice letter with the Commission's Energy Division, which shall include the calculated revenue requirement as described and adjusted in the Decision. SDG&E will clearly identify the overcollections in its Nuclear Decommissioning Adjustment Mechanism (NDAM) and other balancing accounts and regulatory accounts which it will use to offset the revenue requirement, subject to Energy Division determining that the offsets are in compliance with this order. The compliance advice letter shall be served on the service list for the consolidated proceedings and shall describe how SCE will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2013 nuclear decommissioning trust fund balances. The updated information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2014 and 2015. An adjustment to the NDAM 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 advice letter.

3. Within ten (10) days of the effective date of this Decision, Pacific Gas and Electric Company (PG&E) shall file a compliance advice letter 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 advice letter shall be served on the service list for the consolidated proceedings and shall describe how PG&E will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2013 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 2014 and 2015. 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 advice letter.

4. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall serve testimony in their 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.

5. Southern California Edison Company (SCE) shall organize a meeting, within 60 days of the date the decision is issued, to work with Energy Division, San Diego Gas & Electric Company and other interested parties to determine how SCE's cost accounting system for San Onofre Nuclear Generating Station Units 2 and 3 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.

6. Southern California Edison Company (SCE) 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. SCE shall present the cost categorization structure, including how it conforms with the requirements of Ordering Paragraph 5, as supplemental testimony in support of its application associated with its 2014 detailed site-specific decommissioning cost estimate.

7. Southern California Edison Company (SCE) has now filed its 2014 detailed site-specific decommissioning cost estimate for San Onofre Nuclear Generating Station 2 and 3, which reflects the Post-Shutdown Decommissioning Activities Report.. SCE shall provide its NRC-required Integrated Fuel Management Plan through testimony submitted in support of its application to this Commission for review of the 2014 revised and detailed cost estimate. Upon approval, the revised 2014 detailed cost estimate will be considered the most recently approved decommissioning cost estimate for San Onofre Nuclear Generation Station Units 2 and 3.

8. If the Energy Division finds either (1) that Pacific Gas and Electric Company fails to provide required information, or appears to be at significant variance from the costs, scope, or schedule for decommissioning HBPP approved

in Decision14-02-024, or (2) Southern California Edison Company fails to provide required information, or appears to be at significant variance from the costs, scope, or schedule for decommissioning San Onofre Nuclear Generating Station Units 2 and 3 , the Energy Division shall inform the Commission's Executive Director for communication to all Commissioners of such findings for further action, if necessary.

9. Southern California Edison Company and San Diego Gas & Electric Company shall file a joint Tier 1 advice letter no later than March 1, 2015, and serve it on the service list for these proceedings, which identifies the agreed-upon cost tracking system and appropriately facilitates tracking decommissioning expenditures for San Onofre Nuclear Generation Station 2 and 3.

10. In the next Nuclear Decommissioning Triennial Proceeding applications, Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall report the pro rata share of funds accumulated for Nuclear Regulatory Commission (NRC) License termination (radiological decommissioning to meet the NRC standard for license termination) and provide copies of their most recent funding assurance letters (pursuant to 10 C.F.R. 50.75) sent to the NRC.

11. In the next Nuclear Decommissioning Triennial Proceedings , Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall provide testimony to demonstrate (1) that they are in compliance with prior Commission decisions; and (2) they have conducted a comparison of annual cost impacts of retaining Spent Nuclear Fuel in wet versus dry storage for seven years and any longer timeframe assumed in the decommissioning cost estimate.

12. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company (the Utilities) shall disclose as part of their next Nuclear Decommission Cost Triennial Proceeding applications, all settlements, awards, or other resolution of damage claims completed in the triennial period, based on United States Department of Energy failure to accept spent nuclear fuel. The Utilities shall also establish how the recoveries were allocated to the Unit that incurred the cost to ensure that the appropriate share of net proceeds were commensurate with payment of the underlying costs supporting the resolved claims, and to the extent appropriate, placed into the related nuclear decommissioning trust funds or returned to ratepayers in the manner approved by the Commission.

13. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall ensure that their respective Nuclear Decommissioning Trust Fund Committee members timely receive the following information:

- Audited financial statements for the decommissioning trust funds;
- Initiation of Investment fund manager searches;
- Decommissioning cost schedules, including acceleration or any other significant changes;
- Approval of nuclear facility license extension; and
- Withdrawals of Trust Funds for decommissioning expenses.

14. Application (A.) 12-12-012 and A.12-12-013 are closed.

This order is effective today.

Dated December 18, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners