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Vice President & Chief Nuclear Officer

10 CFR 50.82(a)(8)(i)(A)
10 CFR 50.75(h)(2)
10 CFR 50.12

February 13, 2014

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington D.C. 20555-0001

Subject: **Docket Nos. 50-361 and 50-362,**
San Onofre Nuclear Generating Station, Units 2 and 3
Access to Nuclear Decommissioning Trust Funds

References:

1. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission (NRC) dated June 12, 2013; Subject: Certification of Permanent Cessation of Power Operations San Onofre Nuclear Generating Station, Units 2 and 3

2. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission (NRC) dated June 28, 2013; Subject: Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station Unit 3

3. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission (NRC) dated July 22, 2013; Subject: Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station Unit 2

4. Letter from R. St Onge (SCE) to the U. S. Nuclear Regulatory Commission (NRC) dated October 10, 2013; Subject: Response to Request for Additional Information – Units 2 and 3 Decommissioning Funding, San Onofre Nuclear Generating Station, Units 2 and 3

Dear Sir or Madam:

On June 12, 2013 Southern California Edison (SCE) informed the NRC of its intention to permanently cease operation of the San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 as of June 7, 2013 (Reference 1). In the ensuing months SONGS staff has invested significant time and attention to understanding and planning roles and responsibilities in a decommissioning environment. Furthermore, the SONGS staff has been taking prudent initial steps to carefully plan for the timely and prudent decommissioning of the SONGS site. The SONGS staff promptly moved all the fuel from the vessels to the spent fuel pools (References 2 and 3), returned not yet irradiated fuel to the vendor and initiated a wide range of discussions with the SONGS -Participants, potential vendors, peers, and the public to bring clarity to the

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most timely and prudent path forward. Both required and beneficial regulatory submittals are well-underway and will be submitted in coming months.

In the very near future, it will be necessary to commence activities that will require access to the Nuclear Decommissioning Trust (NDT) funds that have been established by the SONGS -Participants as required by California law. The SONGS -Participants' rate-payers have funded these NDTs as directed by the California Public Utilities Commission (CPUC) and in full compliance with NRC requirements. The CPUC has approved ratepayer collections to cover all types of costs of decommissioning SONGS Units 2 and 3, including the NRC license termination costs for which financial assurance is required pursuant 10 CFR 50.75, the spent fuel management costs that must be funded pursuant to 10 CFR 50.54(bb), and the site restoration costs that must be funded under California law and SONGS easement and lease requirements. Information regarding the allocation of trust fund balances to these cost categories was provided by letter dated October 10, 2013 in response to NRC Requests for Additional Information regarding the uses planned for the trust fund balances (Reference 4).

The current NDT balances are adequate to proceed with substantial beneficial near term activities related to decommissioning. As summarized in Attachment 2 to Enclosure 1, the CPUC has a long history of active oversight of the trust funds, drawing from experience with the decommissioning of SONGS Unit 1 and other California nuclear reactor facilities. Further, SCE has filed a "Tier 3" Advice Letter request with the CPUC seeking confirmation of the balances allocated to various purposes, including the current balances for NRC license termination costs. SCE expects that the CPUC will act upon this request in the near future and establish the process for ongoing CPUC oversight for withdrawals of funds from the NDTs. A copy of the SCE request is included in Attachment 2C.

San Diego Gas & Electric Company (SDG&E) plans to submit a similar Tier 3 Advice Letter to the CPUC in the near future. The remaining SONGS Participants, the City of Anaheim and the City of Riverside, have their own rate setting authority and have specific responsibility under California law to accumulate funds in their NDTs for various types of decommissioning costs as described in greater detail in Attachment 2.

The NRC's regulations (10 CFR 50.82(a)(8)(i)(A)) preclude the use of NDT Funds to support activities other than "radiological decommissioning" or "license termination" as narrowly defined in 10 CFR 50.75, unless a licensee maintains comingled funds in the NDT that can be clearly identified as contributed to the NDT for other purposes. As outlined in Enclosure 1, a comprehensive review of the rulemaking history establishes that the NRC's restrictions on the use of trust funds are not intended to apply to commingled funds in an NDT that were accumulated for a broad range of decommissioning purposes other than NRC license termination costs. Information provided in Attachment 2 provides the ratemaking history for the SCE and SDG&E NDTs, showing that ratepayer collections have been approved by the CPUC to pay for estimated spent fuel management costs and site restoration costs, in addition to the NRC license termination costs. Summary information from site specific decommissioning cost estimates dating back to 1993 are provided in Attachment 2A and copies of the relevant CPUC Orders are provided in Attachment 2B.

Information regarding the currently projected site specific costs is provided in Attachment 1, and NRC evaluation of these costs and the existing fund balances together with planned contributions will confirm that adequate funds are projected to be available from the NDTs to pay for all of these costs.

The NRC staff has required some licensees to seek exemptions to use trust funds for non-10 CFR 50.75 purposes such as spent fuel management. However, in these examples, the licensees were not "electric utilities" and did not have the benefit of a state regulatory commission with jurisdiction over the trust funds and with the authority both to designate the existing funds in an NDT collected for non-10 CFR 50.75 purposes and authorize additional ratepayer collections, as necessary, to fund both 10 CFR 50.75 activities and non-10 CFR 50.75 activities. The SONGS Participants are differently situated, because each qualifies as an "electric utility" under NRC's regulation, and each Owner has contributed commingled funds to the NDTs to pay for the full range of decommissioning costs. Each SONGS owner either has cost of service rate regulation by the CPUC or the authority to set their own rates. Thus, the SONGS Participants encourage the NRC to defer to this rate setting authority for purposes of establishing the commingled fund balances in the NDTs that are designated more broadly for and should be available to fund other decommissioning-related activities that are required by California law. The exercise of that authority also assures adequate funding for the more narrowly defined NRC license termination costs for which financial assurance is required pursuant to 10 CFR 50.75.

If the NRC staff concludes that the restrictions on the use of funds in 10 CFR 50.75 and 10 CFR 50.82 apply to the amounts accumulated in the SONGS Units 2 and 3 NDT funds for non-10 CFR 50.75 purposes, SCE requests an exemption from such regulations. The bases for concluding that the exemption requests meet the standards in 10 CFR 50.12 for "Specific Exemption" are provided in Enclosure 2.

SCE and the NRC staff have discussed this dual track submittal and have concluded that this is the appropriate means to achieve adequate regulatory certainty in a timely manner. It is our understanding that the staff will begin with a review of Enclosure 1 to determine whether or not the NRC staff agrees that exemptions are not required. If such a conclusion appears unlikely in a timely manner, the NRC staff will notify SCE that the exemption is the best path forward and promptly begin its review. The content of Enclosure 2 is similar to equivalent submittals on other dockets thereby facilitating the NRC's review.

It is in every stake-holders' best interest for the NDT funds to be effectively utilized to achieve all the purposes for which they were collected from the rate-payers with oversight from the appropriate regulatory bodies with jurisdiction over such matters. The CPUC has primary jurisdiction with regard to rate-payer funding of and disbursement of funds from the SONGS Units 2 and 3 NDTs, and NRC should defer to the CPUC's rate setting and comprehensive oversight of trust fund disbursements to SCE and SDG&E. The NRC's role is properly focused on technical aspects of decommissioning, on assuring that adequate funding is provided for radiological decommissioning as well as spent fuel management, and on approving the criteria established for releasing the site for restricted or unrestricted use. With respect to decommissioning funding assurance, the NRC can rely on the fact that the SONGS Participants are electric utilities that are either rate regulated by the CPUC or that have their own rate-setting authority.

This letter requests that the NRC either agree that such an exemption is not necessary or grant appropriate exemption(s) to clearly allow use of all the NDTs for their intended purposes. In order to avoid any adverse financial impact or delays in the decommissioning of SONGS Units 2 and 3, it is imperative that access to these funds not be delayed beyond the time-frame expected to set up appropriate processes for CPUC oversight and authorization to access the funds in the NDTs. We anticipate that the CPUC may authorize access to the funds in the

NDTs for SCE and San Diego Gas and Electric (SDG&E) as early as March 2014 and no later than the second quarter of 2014.

This letter contains one new commitment. SCE will provide the NRC a copy of the CPUC Resolution in response to our Tier 3 Request upon its receipt. Further, SDG&E will make the CPUC's Resolution to their Request available to the NRC as well.

If there are any questions or if additional information is needed, please contact me or R.J. St. Onge at 949-368-6240.

Sincerely,

Enclosures

1. San Onofre Nuclear Generating Station Units 2 and 3 Request to Confirm that Exemptions are Not Required in Support of Nuclear Decommissioning Trust Fund Access
2. San Onofre Nuclear Generating Station Units 2 and 3 Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) and 50.75(h)(2)

Attachments

1. Nuclear Decommissioning Trust Funds Annual Cost and Contribution Cash Flows
2. San Onofre Nuclear Generating Station Units 2 and 3 Summary of CPUC Filings and Orders Nuclear Decommissioning Trust Funds (including copies of relevant documents)

cc: Mark Dapas, Regional Administrator, NRC Region IV
C. Gratton, NRC Project Manager, San Onofre Units 2 and 3 Decommissioning
R. E. Lantz, NRC Region IV, San Onofre Units 2 and 3
G. G. Warrick, NRC Senior Resident Inspector, San Onofre Units and 2

ATTACHMENT 1

NUCLEAR DECOMMISSIONING TRUST FUNDS
ANNUAL COST AND CONTRIBUTION CASH FLOWS

February 13, 2014

SONGS Units 2 and 3
Decommissioning Funding Summary

Year	Radiological Decontamination	Spent Fuel Management	Site Restoration	Total	Contributions to Trust Fund	Available Funds
2013	59,623	37,247	44,595	141,465	32,300	3,770,000
2014	118,274	73,887	88,463	280,624	32,300	
2015	142,383	85,095	59,831	287,308	32,300	
2016	166,556	96,382	31,752	294,691	32,300	
2017	166,101	96,119	31,666	293,886	32,300	
2018	166,101	96,119	31,666	293,886	32,300	
2019	166,101	96,119	31,666	293,886	32,300	
2020	166,556	96,382	31,752	294,691	32,300	
2021	166,101	96,119	31,666	293,886	32,300	
2022	166,101	96,119	31,666	293,886	32,300	
2023	166,101	96,119	31,666	293,886		
2024	35,629	26,984	150,932	213,545		
2025	35,533	26,910	150,741	213,184		
2026	35,533	26,910	150,519	212,962		
2027	17,620	22,272	74,641	114,532		
2028	-	17,757	-	17,757		
2029	-	17,708	-	17,708		
2030	-	17,708	-	17,708		
2031	-	17,708	-	17,708		
2032	-	17,757	-	17,757		
2033	-	17,708	-	17,708		
2034	-	17,708	-	17,708		
2035	-	17,708	-	17,708		
2036	-	17,757	-	17,757		
2037	-	17,708	-	17,708		
2038	-	17,708	-	17,708		
2039	-	17,708	-	17,708		
2040	-	17,757	-	17,757		
2041	-	17,708	-	17,708		
2042	-	17,708	-	17,708		
2043	-	17,708	-	17,708		
2044	-	17,757	-	17,757		
2045	-	17,708	-	17,708		
2046	-	17,708	-	17,708		
2047	-	17,708	-	17,708		
2048	-	17,757	-	17,757		
2049	-	17,708	-	17,708		
2050	1,779	17,863	66,058	85,700		
2051	1,779	17,863	66,058	85,700		
	$1,777,867	$1,494,378	$1,105,340	$4,377,585	323,000	

Notes: Costs are in 2013 dollars (in thousands). Trust fund balance at July 31, 2013 was $3,770,000.

ENCLOSURE 1

San Onofre Nuclear Generating Station Units 2 and 3
Request to Confirm That Exemptions Are Not Required in Support of Nuclear Decommissioning Trust Fund Access

FEBRUARY 13, 2014

I. DESCRIPTION

Southern California Edison (SCE) and the other SONGS Participants request written confirmation that an exemption from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) is not required for the use of nuclear decommissioning trust fund (NDT) balances identified as being designated to pay for irradiated fuel management and site restoration costs. SCE and the other of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 Participants have accumulated funds in their NDTs for broad categories of decommissioning related expenses as required by California law. Thus, the SONGS NDTs are not solely designated for purposes of "decommissioning" as defined for purposes of 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2). SCE has discussed this issue with appropriate NRC staff. Greater regulatory certainty is needed regarding the applicable requirements, and it was agreed that it can best be obtained by requesting confirmation on the docket.

II. BACKGROUND

By letter dated June 12, 2013, SCE informed the NRC of its intention to permanently cease operation of SONGS UNITS 2 and 3 as of June 7, 2013 (Reference 1). By letter dated March 27, 2013, (Reference 2) SCE had most recently updated the NRC in a status report regarding the decommissioning funding assurance for SONGS Units 2 and 3 as required by 10 CFR 50.75(f)(1). The NRC (in Reference 3) requested additional information directly associated with the current subject. SCE (in Reference 4) responded with a summary of how the California Public Utilities Commission (CPUC) assured compliance with applicable California law with regard to the oversight of such funds. SCE further provided detailed information regarding the allocations of funds in the trust for the three categories of expenses consistent with our interactions with the CPUC in support of the Nuclear Decommissioning Cost Triennial Proceeding ("Triennial Proceeding").

The Triennial Proceeding is a separate docket before the CPUC that requires the regulated utilities in the State to meet stringent standards associated with estimating costs for all phases of nuclear decommissioning. If the balance, projected growth and current contributions levels are determined to not be adequate to meet the entire project's costs, the contributions are adjusted. This review is informed by independent experts and demonstrates the thoroughness with which the CPUC exercises their oversight of decommissioning costs

The information provided in Reference 4 was based upon the most recent Decommissioning Cost Estimate (DCE) (Reference 5) that was requested by the CPUC in March 2013 in order to address an assumed shutdown of SONGS Unit 2 and 3 in 2013 and submitted to the CPUC in July 2013. The allocation of the balances in the fund demonstrates that the NDT balances, projected growth and planned contributions contain sufficient funds to address the estimated costs of radiological decommissioning, irradiated fuel management, and site restoration, which includes non-radiological decommissioning and payment of other costs that are required to be included as decommissioning expenses under California law (i.e., severance costs). The decommissioning cost estimates generated for SONGS Units 2 and 3 have consistently included not only the narrowly defined costs for radiological decommissioning for which financial assurance is required pursuant to 10 CFR 50.75, but also all other elements of expected decommissioning costs including spent fuel management and site restoration. These other categories of costs have been reported at various times both to the CPUC and to the NRC.

A summary of historical cost estimates submitted to the CPUC and CPUC Orders authorizing ratepayers collections based upon these projected expenses is included for further information in Attachment 2. The record of CPUC Orders establishes that ratepayer collections have been authorized to accumulate funds for irradiated fuel management and site restoration, as well as the radiological decommissioning contemplated by 10 CFR 50.75. Moreover, as discussed further below, SCE expects to obtain a CPUC acknowledgement of the purpose of prior rate collections and planned use of NDT funds for these purposes, as well as a designation of the specific account balances that should be currently allocated to each purpose. Both the CPUC and NRC will be periodically updated regarding progress and any change in plans or estimates. Any required changes to rates and allocated balances will be directed by the CPUC.

SCE has committed to the CPUC to update the DCE and plans to similarly update the information provided to the NRC in both the periodic funding assurance updates (due in March of each year) and as part of the required decommissioning submittals. Nevertheless, the current available information demonstrates that adequate funding assurance is being provided for all aspects of decommissioning, including state mandated costs beyond those mandated by NRC. In Attachment 1, the projected annual expenses are provided based upon the most recent July 2013 site specific cost estimate for an assumed 2013 shutdown that was requested by and submitted to the CPUC. The July 2013 study provided cash flows in 2011 dollars. However, in Table 1 these cash flows have been escalated so that the costs are expressed in 2013 dollars. In addition, the July 31, 2013 NDT balances are provided consistent with the balances reported to the NRC in Reference 4. Table 1 includes a separate annual itemization for license termination (radiological decommissioning) costs, irradiated fuel management costs and site restoration costs (including other state mandated transitional costs). NRC evaluations of these costs and the existing fund balances together with planned contributions will confirm that adequate funds are projected to be available from the NDTs to pay for all of these costs.

The NRC has long acknowledged that licensees could accumulate funds for these other purposes in their trust funds commingled with the funds for 10 CFR 50.75 purposes (radiological decommissioning).

For example, in its 1996 rulemaking (Reference 6), the NRC responded to comments on this issue as follows:

> The final rule does not prohibit licensees from having separate subaccounts for other activities in the decommissioning trust fund if minimum amounts specified in the rule are maintained for radiological decommissioning.

The NRC reiterated these principles in its 2002 rulemaking (Reference 7), which tightened the restrictions on the use of funds in 10 CFR 50.75 trusts, but; nevertheless continued to recognize the potential commingling of funds earmarked for non-10 CFR 50.75 purposes. With respect to these funds, the NRC responded to comments as follows:

> As to the statement made by commenters that restrictions should not apply to funds held in trust for purposes other than radiological decommissioning, the Commission's position is that withdrawals for nonradioactive decommissioning expenses that do not affect the amount of funds remaining for radiation decommissioning costs are not covered by this rule. However, the Commission is not proposing that licensees institute separate trusts to account for the different types of activity. The Commission appreciates the benefits that some licensees may derive from their use of a single trust fund for all of their decommissioning costs, both radiological and not; but, as stated above, a licensee must be able to identify the individual amounts contained within its single trust.

In Reference 4, SCE identified the trust fund balances allocable to different purposes that go beyond the narrow definition of radiological decommissioning contemplated by 10 CFR 50.75. As discussed further below, these amounts are expected to be confirmed by the CPUC as requested by Reference 9, so that the CPUC will specifically identify the individual amounts contained within the trusts that are designated for other purposes.

More recently, the NRC in Regulatory Issue Summary 2001-07, Rev. 1 (Reference 8) recognized that funds for all decommissioning purposes could be maintained in a single decommissioning trust account, and therefore clarified to licensees that they need to be able to "identify and account for the NRC radiological decommissioning funds" in the account:

> The NRC has not precluded the commingling in a single account of funds accumulated to comply with NRC radiological decommissioning requirements and funds accumulated to address State site restoration costs (State costs) and spent fuel management costs, as long as the licensee is able to identify and account for the NRC radiological decommissioning funds that are contained within its single account.

As summarized in Reference 4, and detailed in Attachment 2, SCE and the other SONGS Participants have collected funds from ratepayers and accumulated funds in the NDTs to fund three primary categories of costs: (1) NRC license termination; (2) irradiated fuel management; and (3) site restoration.

On November 18, 2013, SCE filed a Tier 3 Advice Letter (Reference 9) with the CPUC to obtain authorization for the use of funds in the near term and to establish processes for further CPUC oversight of withdrawals from SCE's decommissioning trusts. In this same proceeding, SCE has requested that the CPUC confirm the amounts accumulated for NRC license termination, so that these amounts could be accounted for separately from the amounts for irradiated fuel management and site restoration. The amounts for NRC license termination will be used exclusively for decommissioning in accordance with 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2). The other CPUC rate-regulated Co-owner (San Diego Gas & Electric Company) is filing a similar request.

III. **CONCLUSION**

Pursuant to NRC guidance and rulemaking history the other amounts in the trust funds are not subject the restrictions in these two regulations, and thus, no exemption is necessary. Further, the allocation of fund balances within the trust was the subject of NRC requests for additional information regarding the purpose of funds in the SONGS Units 2 and 3 trust funds. SCE provided the requested information based on the longstanding history of CPUC approving revenues from ratepayers to fund estimated costs for: (1) NRC license termination; (2) irradiated fuel management; and (3) site restoration. The estimated costs and revenue requirements have been refined and evolved over time through rigorous oversight exercised by the CPUC. Moreover, the CPUC is expected to designate the amounts accumulated in the trust funds for each of the three key categories of costs.

SCE requests written confirmation that the NDT Trust balances are not, exclusively designated for purposes of "Decommissioning" as narrowly defined for purposes of 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2). Therefore, an exemption from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) is not required for the use of such funds identified by the CPUC as being accumulated to pay for irradiated fuel management costs and site restoration costs, which include non-radiological decommissioning and other state mandated costs.

IV. References

1. Letter from P. Dietrich, Southern California Edison, to U.S. Nuclear Regulatory Commission, Attention: Document Control Desk, Subject: Dockets 50-361 and 50,362, Certification of Permanent Cessation of Power Operations, San Onofre Nuclear Generating Station Units 2 and 3, dated June 12, 2013.

2. Letter from R. J. St. Onge (SCE) to Document Control Desk (NRC) Subject: "Docket Nos. 50-361 and 50-362 10 CFR 50.75(f)(1) Decommissioning Funding Report, San Onofre Nuclear Generating Station Units 2 and 3", dated March 27, 2013.

3. Letter from Brian Benny (NRC) to P. T. Dietrich (SCE), Subject: "San Onofre Nuclear Generating Station, Units 2 and 3 – Request for Additional Information Regarding 2013 Decommissioning Funding Status Reports (TAC Nos. MF 2243 and MF 2244), dated September 12, 2013

4. Letter from R. J. St. Onge (SCE) to Document Control Desk (NRC), Subject Dockets Nos. 50-361 and 50-362, Responses to Request for Additional Information, Units 2 and 3 Decommissioning Funding, San Onofre Generating Station, Units 2 and 3, dated October 10, 2013.

5. Decommissioning Cost Estimate, 2013 Scenario, dated July 11, 2013, ABZ, Incorporated. Used in support of Nuclear Decommissioning Cost Triennial Proceeding, Exhibit SCE-12.

6. 1996 Decommissioning Rulemaking Package, Comment Resolution Package, 61 Fed. Reg. 39278 (July 29. 1996)

7. Final Rule, Decommissioning Trust Provisions, 67 Fed. Reg. 78,332, 78,340 (Dec. 24, 2002)

8. Regulatory Issue Summary 2001 07, Rev.1, "10 CFR 50.75 Reporting and Recordkeeping for Decommissioning Planning," dated January 8, 2009,

9. Letter from Megan Scott-Kakures, Southern California Edison, to Public Utilities Commission of the State of California Energy Division Submitting a Tier 3 Advice Letter Requesting (1) Authorization of Disbursements from the Master Trusts for San Onofre Nuclear Generating Station; (2) Approval of Tier 2 Advice Letter to Process for Future Disbursements; (3) Designation of Trust Amounts Set Aside for License Termination; and (4) Approval of Balancing Account, dated November 18, 2013.

ENCLOSURE 2

San Onofre Nuclear Generating Station Units 2 and 3
Request for Exemption from 10 CFR 50.82(a)(8)(i)(A) and 50.75(h)(2)

FEBRUARY 13, 2014

I. DESCRIPTION

Southern California Edison (SCE), pursuant to 10 CFR 50.12 "Specific Exemptions," requests an exemption from 10 CFR 50.82(a)(8)(i)(A) to allow SCE and other of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 Participants to use funds from the SONGS Units 2 and 3 nuclear decommissioning trust funds (NDTs) for irradiated fuel management and site restoration costs. SCE also requests an exemption from 10 CFR 50.75(h)(2) for the same reasons, to allow NDTs disbursements to pay for irradiated fuel management and site restoration activities and to allow such disbursements without prior notice to the NRC.

By letter dated June 12, 2013 (Reference 1), SCE informed the NRC of its intention to permanently cease operation of SONGS Units 2 and 3 as of June 7, 2013. By letter dated March 27, 2013 (Reference 2), SCE last updated the NRC in a status report regarding the decommissioning funding assurance for SONGS Units 2 and 3 as required by 10 CFR 50.75(f)(1). The NRC (in Reference 3) requested additional information directly associated with the current subject. SCE (in Reference 4) responded with a summary of how the California Public Utilities Commission (CPUC) assured compliance with applicable California law with regard to the oversight of such funds. It further supplied explicit allocations of funds in the trust for the three primary categories of expenses.

The Decommissioning Cost Estimate (DCE) upon which these submittals were based and the allocation of the balances in the fund demonstrates that the NDT balances, projected growth and planned contributions contain sufficient funds to address the estimated costs of radiological decommissioning, irradiated fuel management, and site restoration, which includes non-radiological decommissioning and payment of other state mandated costs that are required to be included as decommissioning expenses under California law. The decommissioning cost estimates generated for SONGS Units 2 and 3 have consistently included not only the narrowly defined costs for radiological decommissioning for which financial assurance is required pursuant to 10 CFR 50.75, but also all other elements of expected decommissioning costs including irradiated fuel management and site restoration. These other categories of costs have been reported at various times both to the CPUC and to the NRC.

10 CFR 50.82(a)(8)(i)(A) states that nuclear decommissioning trust funds may be used by licensees if the withdrawals are for expenses for legitimate decommissioning activities consistent with the definition of decommissioning in 10 CFR 50.2. Similarly, 10 CFR 50.75(h)(2) requires that decommissioning trust agreements provide that disbursements (other than for incidental costs, such as administrative expenses, taxes and fees) are restricted to decommissioning expenses until final decommissioning is completed and requires a 30 day notice for disbursements made unless they are for incidental costs or for costs to be paid pursuant to 10 CFR 50.82(a)(8).

Exemptions from 10 CFR 50.82(a)(8)(i)(A) and 50.75(h)(2) are requested to allow SCE and the other SONGS Participants to withdraw and use NDT balances to pay for irradiated fuel management activities and site restoration costs. The term "site restoration" is used in this request to refer to all types of non-radiological decommissioning activities and their costs, including transition severance costs, for which the CPUC has authorized collection from ratepayers to be contributed to the NDTs. The NDT balances, projected growth and planned contributions provide sufficient funds to address estimated costs needed for radiological decommissioning, irradiated fuel management and site restoration costs. Therefore, these exemptions would not present an undue risk to the public health and safety or prevent decommissioning from being completed as planned.

II. BACKGROUND

The DCE upon which Reference 2 was based was submitted to the CPUC as part of the Nuclear Decommissioning Cost Triennial Proceeding (Reference 5). The DCE is a detailed, site-specific cost estimate which includes information associated with the cost of radiological decommissioning (license termination), irradiated fuel management, and site restoration as required by California law and as approved by the CPUC. Although SCE has committed to the CPUC to update the DCE and will similarly update the NRC in upcoming decommissioning submittals, the existing information is more than sufficient to demonstrate funding assurance for all aspects of decommissioning, including state mandated costs beyond those mandated by NRC. The cash flow summary (provided as Attachment 1) demonstrates that the NDT balances, projected growth and planned contributions provide sufficient funds to address the estimated amount needed to cover all of these activities.

In Attachment 1, the projected annual expenses are provided based upon the most recent July 2013 site specific cost estimate for an assumed 2013 shutdown that was requested by and submitted to the CPUC. The July 2013 study provided cash flows in 2011 dollars. However, in Table 1 these cash flows have been escalated so that the costs are expressed in 2013 dollars. In addition, the July 31, 2013 NDT balances are provided consistent with the balances reported to the NRC in Reference 4. Table 1 includes a separate annual itemization for license termination (radiological decommissioning) costs, irradiated fuel management costs and site restoration costs (including other state mandated transitional costs). NRC's evaluation of these costs and the existing fund balances together with planned contributions will confirm that adequate funds are projected to be available from the NDTs to pay for all of these costs. However, 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) have been interpreted as an impediment to such use.

10 CFR 50.82(a)(8)(i) (Reference 6) states (in part) that decommissioning trust funds may be used by licensees if:

> (A) The withdrawals are for expenses for legitimate decommissioning activities consistent with the definition of decommissioning in Section 50.2;

10 CFR 50.75(h)(2) (Reference 7) similarly requires that decommissioning trust agreements must provide that disbursements (other than ordinary and incidental expense) are restricted to decommissioning expenses until final decommissioning is completed. 10 CFR 50.2 provides the following definition:

Decommission means to remove a facility or site safely from service and reduce residual radioactivity to a level that permits:

1) Release of the property for unrestricted use and termination of the license; or

2) Release of the property under restricted conditions and termination of the license.

NRC staff guidance (Reference 8) regarding the regulations discussed above indicates that decommissioning activities do not generally include irradiated fuel management, which is considered to be an operational activity. "Other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction and operation of an independent spent fuel storage installation (ISFSI)... are not included in the NRC definition of decommissioning." The same guidance (Reference 8) does includes spent fuel pool related costs, such as draining the pool and removing, decontaminating and disposing of spent fuel storage racks and presumably also includes disposition of the spent fuel pool buildings and associated structures.

However, SCE and the other SONGS Participants have commingled funds in their trust funds that have been collected from ratepayers to pay decommissioning related expenses, as required under California law, that g beyond the narrow category of costs covered by 10 CFR 50.75 and 10 CFR 50.82. To the extent the NRC staff has determined that the entire NDT balances are subject to the requirements of 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2), SCE requests that NRC grant exemptions to these requirements. Further information in support of these exemption requests is provided below.

III. JUSTIFICATION FOR EXEMPTIONS AND SPECIAL CIRCUMSTANCES

10 CFR 50.12 states that the Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of the regulations of Part 50 which are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the defense and security. 10 CFR 50.12 also states that the Commission will not consider granting an exemption unless special circumstances are present. As discussed below, this exemption request satisfies the provisions of Section 50.12.

A. *The exemptions are authorized by law*

The proposed exemptions would allow SCE and the other SONGS Participants to use funds from the NDTs for irradiated fuel management and site restoration. As stated above, 10 CFR 50.12 allows the NRC to grant exemptions from the requirements of 10 CFR Part 50. Additionally, the Atomic Energy Act of 1954, as amended (Act) does not address this subject. Further, the exemption is necessary to allow the SONGS Participants to efficiently comply with California law.

Therefore, the proposed exemptions would not result in a violation of the Act, and the exemptions are authorized by law.

B. *The exemptions will not present an undue risk to public health and safety*

The underlying purpose of 10 CFR 50.82(a)(8)(i)(A) and 50.75(h)(2) is to provide reasonable assurance that adequate funds will be available for license termination (also referred to as radiological decommissioning) of power reactors within 60 years of cessation of operations. Based on the site-specific cost estimate and the cash flow analysis, use of the NDTs in the proposed manner will not adversely impact SCE's ability to terminate the SONGS Units 2 and 3 licenses (i.e. complete radiological decommissioning) within 60 years. Therefore, the underlying purpose of the regulations will continue to be met. Since the underlying purpose of the rules will continue to be met, the exemptions will not present an undue risk to the public health and safety.

C. *The exemptions are consistent with the common defense and security*

The proposed exemptions would allow SCE and the other SONGS Participants to use NDT balances for irradiated fuel management and site restoration. All such activities are an integral part of the planned SONGS Units 2 and 3 decommissioning process. Use of the NDTs will support and not adversely affect SCE's ability to physically secure the site or protect special nuclear material. Therefore, the proposed exemptions are consistent with the common defense and security.

D. *Special Circumstances*

Pursuant to 10 CFR 50.12(a)(2), the NRC will not consider granting an exemption to its regulations unless special circumstances are present. SCE believes that special circumstances are present as discussed below.

1. **Application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule. (10 CFR 50.12(a)(2)(ii))**

   The underlying purpose of 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) is to provide reasonable assurance that adequate funds will be available for decommissioning of power reactors within 60 years of cessation of operations. The inability or substantial delay in the withdrawal of funds from the NDTs for activities associated with irradiated fuel management and site restoration would interfere with the prompt decommissioning of SONGS Units 2 and 3. In contrast, the site-specific decommissioning cost analysis demonstrates that adequate funds will be available in the NDTs, from existing balances, planned contributions and projected earnings of NDT assets, in order to complete all decommissioning activities, including license termination, irradiated fuel management, and site restoration. Thus, the purpose of the regulations will be fulfilled if the NDTs are used to pay for all planned activities.

The 30-day notification provision in 50.75(h)(2) was not intended to duplicate other reporting requirements that would exist after a plant commences decommissioning. During the rulemaking establishing this requirement, a commenter observed that licensees that have complied with the requirements of 10 CFR 50.82(a)(4) regarding submittal of a PSDAR and control disbursements in accordance with the provisions of 10 CFR 50.82(a)(6), (a)(7) and (a)(8) should be exempt from providing notice regarding disbursements (Reference 9). The NRC agreed with the comment, because requiring notification in such circumstances would not provide any additional assurance that funding is available and would duplicate notification requirements in 50.82. If the NRC grants the requested exemption allowing SCE and the other SONGS Participants to use their NDTs for other aspects of decommissioning, the same consideration would justify dispensing with the 30-day notification requirement as well. The annual reporting requirements promulgated in 10 CFR 50.82(a)(4)(v) and (vi) will allow continual NRC oversight of the status of the NDTs. Applying the 30-day advance notification requirement in 50.75(h)(2) to disbursements for irradiated fuel management activities would duplicate other reporting requirements and is not necessary to achieve the underlying purposes of this rule.

Therefore, since the underlying purposes of the rules would be achieved by allowing SCE and the other SONGS Participants to use the NDTs to fund all activities which are an integral part of the decommissioning process, the special circumstances required by 10 CFR 50.12(a)(2)(ii) exist.

2. **Compliance would result in undue hardship or other costs that are significantly in excess of those contemplated when the regulation was adopted, or that are significantly in excess of those incurred by others similarly situated. (10 CFR 50.12(a)(2)(iii)).**

Prevention of SCE and the other SONGS Participants from use of the NDT balances identified by the CPUC as being designated for irradiated fuel management and site restoration activities would create an unnecessary financial burden on SCE and the other SONGS Participants (and their ratepayers) without any corresponding safety benefit. The adequacy of the NDTs to cover the cost of activities associated with the different elements of decommissioning is supported by a site-specific decommissioning cost analysis. If SCE and the other SONGS Participants cannot use their NDTs for all of the required activities, they or their ratepayers may be forced to provide additional funding. Surplus funding from the NDTs would not be available until after license termination is completed following removal of all irradiated fuel from the site, which may not occur for many decades. Such an outcome would impose an unnecessary or undue burden in excess of that contemplated when the regulation was adopted.

Therefore, strict compliance with the rule would result in an undue hardship or other costs that are significantly in excess of those contemplated when the regulation was adopted, or that are significantly in excess of those incurred by others similarly situated and the special circumstances required by 10 CFR 50.12(a)(2)(iii) exist.

3. **The exemption would result in benefit to the public health and safety that compensates for any decrease in safety that may result from the grant of the exemption. (10 CFR 50.12(a)(2)(iv))**

   The proposed exemptions would allow the use of the NDTs for all decommissioning activities and would facilitate the prompt decommissioning of SONGS Units 2 and 3 which would directly benefit public health and safety. Adequate funds will be available in the NDTs to complete all activities associated with license termination, irradiated fuel management, and site restoration. Furthermore, there is no decrease in safety associated with the NDTs being used to fund other activities directly associated with decommissioning. Therefore, since granting the exemption would not result in a decrease in safety, the special circumstances required by 10 CFR 50.12(a)(2)(iv) exist.

IV. ENVIRONMENTAL CONSIDERATION

The proposed exemptions meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(25), because the proposed exemption involves: (i) no significant hazards consideration; (ii) no significant change in the types or significant increase in the amounts of any effluent that may be released offsite; (iii) no significant increase in individual or cumulative occupational radiation exposure; (iv) no significant construction impact; (v) no significant increase in the potential for consequences from radiological accidents; and (vi) the requirements from which the exemption is sought involve surety, insurance or indemnity requirements or other requirements of an administrative nature. Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed exemptions.

i. No significant hazards consideration

SCE has evaluated the proposed exemptions to determine whether or not a significant hazards consideration is involved by focusing on the three standards set forth in 10 CFR 50.92 as discussed below:

1. **Do the proposed exemptions involve a significant increase in the probability or consequences of an accident previously evaluated?**

The proposed exemptions would allow SCE and the other SONGS Participants to withdraw funds from the NDTs to conduct related activities. The proposed exemptions have no effect on plant structures, systems, and components (SSCs) and no effect on the capability of any plant SSC to perform its design function. The proposed exemptions would not increase the likelihood of the malfunction of any plant SSC. The proposed exemptions would have no effect on any of the previously evaluated accidents in the SONGS Units 2 and 3 Updated Final Safety Analysis Report. Use of funds in the NDTs as allowed under the exemptions will not affect the probability of occurrence of any previously analyzed accident.

Therefore, the proposed exemptions do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. **Do the proposed exemptions create the possibility of a new or different kind of accident from any accident previously evaluated?**

The proposed exemption does not involve a physical alteration of the plant. No new or different type of equipment will be installed and there are no physical modifications to existing equipment associated with the proposed exemption. Similarly, the proposed exemption would not physically change any structures, systems, or components involved in the mitigation of any accidents. Thus, no new initiators or precursors of a new or different kind of accident are created. Furthermore, the proposed exemption does not create the possibility of a new accident as a result of new failure modes associated with any equipment or personnel failures. No changes are being made to parameters within which the plant is normally operated, or in the set-points which initiate protective or mitigating actions, and no new failure modes are being introduced.

Therefore, the proposed exemptions do not create the possibility of a new or different kind of accident from any previously evaluated.

3. **Do the proposed exemptions involve a significant reduction in a margin of safety?**

The proposed exemptions do not alter the design basis or any safety limits for the plant. The proposed exemptions do not impact station operation or any plant SSC that is relied upon for accident mitigation.

Therefore, the proposed exemptions do not involve a significant reduction in a margin of safety.

Based on the above, SCE concludes that the proposed exemptions present no significant hazards consideration, and, accordingly, a finding of "no significant hazards consideration" is justified.

ii. **There is no significant change in the types or significant increase in the amounts of any effluent that may be released offsite.**

There are no expected changes in the types, characteristics, or quantities of effluents discharged to the environment associated with the proposed exemption. There are no materials or chemicals introduced into the plant that could affect the characteristics or types of effluents released offsite. In addition, the method of operation of waste processing systems will not be affected by the exemptions. The proposed exemptions will not result in changes to the design basis requirements of SSCs that function to limit or monitor the release of effluents. Therefore, the proposed exemptions will result in no significant change to the types or significant increase in the amounts of any effluents that may be released offsite.

iii. **There is no significant increase in individual or cumulative occupational radiation exposure.**

The exemptions would result in no expected increases in individual or cumulative occupational radiation exposure on either the workforce or the public. There are no expected changes in normal occupational doses. Likewise, design basis accident dose is not impacted by the proposed exemption.

iv. **There is no significant construction impact.**

There are no construction activities associated with the proposed exemptions. The only construction activities indirectly associated with the proposed exemptions are the funding of expansion of the ISFSI pad and temporary features added to facilitate interim configurations, decontamination or dismantlement.

v. **There is no significant increase in the potential for consequences from radiological accidents.**

See the no significant hazards considerations discussion in item 1 above.

vi. **The requirements from which exemptions are sought involve surety, insurance or indemnity requirements or other requirements of an administrative nature.**

The underlying purpose of the requirements from which exemptions are sought is to provide reasonable assurance that adequate funds will be available for decommissioning of power reactors within 60 years of cessation of operations. These requirements provide assurance for decommissioning funding.

V. <u>CONCLUSION</u>

SCE requests, pursuant to the provisions of 10 CFR 50.12, "Specific exemptions," exemptions from 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2) for SONGS Units 2 and 3. The proposed exemptions would allow SCE and the other SONGS Participants to use funds from the SONGS NDTs for decommissioning related expenses (irradiated fuel management and site restoration) and make such disbursements in the same manner as withdrawals for license terminations costs (radiological decommissioning).

Granting these exemptions will be consistent with the purposes underlying NRC decommissioning regulations as it: (1) would not foreclose release of the site for possible unrestricted use; (2) would not result in significant environmental impacts not previously reviewed by the NRC; and (3) would not undermine the existing and continuing reasonable assurance that adequate funds will be available for decommissioning.

The requested exemptions are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security, and special circumstances are present as set forth in 10 CFR 50.12(a)(2).

VI. REFERENCES

1. Letter from P. Dietrich, Southern California Edison, to U.S. Nuclear Regulatory Commission, Attention: Document Control Desk, Subject: Dockets 50-361 and 50,362, Certification of Permanent Cessation of Power Operations, San Onofre Nuclear Generating Station Units 2 and 3, dated June 12, 2013.

2. Letter from R. J. St. Onge, Southern California Edison to U. S. Nuclear Regulatory Commission, Subject: Docket Nos. 50-361 and 50-362, 10 CFR 50.71(f)(1) Decommissioning Funding Report San Onofre Nuclear Generating Station Units 2&3, dated March 27, 2013

3. 5 Decommissioning Cost Estimate, 2013 Scenario, dated July 11, 2013, ABZ, Incorporated. Used in support of Nuclear Decommissioning Cost Triennial Proceeding, Exhibit SCE-12.

4. 3 Letter from Brian Benny (NRC) to P. T. Dietrich (SCE), Subject: "San Onofre Nuclear Generating Station, Units 2 and 3 – Request for Additional Information Regarding 2013 Decommissioning Funding Status Reports (TAC Nos. MF 2243 and MF 2244), dated September 12, 2013

5. 4 Letter from R. J. St. Onge (SCE) to Document Control Desk (NRC), Subject Dockets Nos. 50-361 and 50-362, Responses to Request for Additional Information, Units 2 and 3 Decommissioning Funding, San Onofre Generating Station, Units 2 and 3.

6. Title 10 Code of Federal Regulations, Part 50, 50.82 "Termination of License" at 50.82(a)(8)(i)

7. Title 10 Code of Federal Regulations, Part 50, 50.75 "Reporting and Recordkeeping for Decommissioning Planning" at 50.75(h)(2)

8. NUREG-1713, "Standard Review Plan for Decommissioning Cost Estimate for Nuclear Power Reactors" published December, 2004

9. Final Rule, Decommissioning Trust Provisions, 67 Fed. Reg. 78,332, 78,340, dated Dec. 24, 2002

ATTACHMENT 2

San Onofre Nuclear Generating Station Units 2 and 3
Summary of CPUC Filings and Orders
Nuclear Decommissioning Trust Funds

FEBRUARY 13, 2014

Accumulation of Trust Funds Based Upon
Site Specific Decommissioning Cost Estimates

The ratepayers that have received electricity generated by the San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, have provided funding through rates to fund nuclear decommissioning trust (NDTs) established by Southern California Energy Company (SCE), San Diego Gas & Electric Company (SDG&E), the City of Anaheim (Anaheim), and the City of Riverside (Riverside). These NDTs are intended to provide funding for the SONGS Units 2 and 3 decommissioning costs as broadly defined under California law.

The NDTs were required to be established by California's Nuclear Facility Decommissioning Act of 1985, which is codified in the California Public Utilities Code in Sections 8321-8330. Section 8325 requires that both electric utilities regulated by the California Public Utilities Commission (CPUC) and publicly owned utilities, such as Anaheim and Riverside, must establish NDT funds and provide for revenue to be collected in rates to make contributions to the NDTs. Section 8324(d) specifically defines decommissioning to mean not only license termination as defined by the Nuclear Regulatory Commission (NRC), but also "other activities and costs, if any" provided they meet the broader definition of decommissioning allowed by the Treasury Regulations governing a "qualified" NDT. Moreover, Section 8330 requires that a utility involved in decommissioning must provide "assistance in finding alternative employment opportunities for its employees who become unemployed as the result of decommissioning," *i.e.*, severance benefits.

Consistent with the governing California law, and as directed by the CPUC and the Cities' rate setting boards, the NDTs for SONGS have long been funded with ratepayer revenue collected to pay estimated expenses for spent fuel management such as dry cask storage and non-radiological site restoration, in addition to the expected radiological costs that fall within NRC's narrow definition of decommissioning in 10 CFR 50.75. For example, TLG Services prepared a site specific study for SONGS, Units 1, 2 and 3 1993, which specifically addressed site specific factors that included plans for dry cask storage of spent fuel for all three units (Section 4.3.1 of the TLG Study) and the unique non-radiological site restoration activities potentially driven by the lease agreement with the U.S. Government (Section 4.3.5 of the TLG Study). These non-10 CFR 50.75 costs were included in the cost estimate in the TLG Study, and the "Dry Cask Storage Costs" for each unit were specifically broken out in Table 8.1, which summarizes the costs. Excerpts from this cost study, including Table 8.1, are provided in Attachment 2A.

This cost estimate was accepted by the CPUC in establishing ratepayer collections for the NDTs in an SCE rate case Decision and Order, Decision 96-01-011, at 217-218 (January 10, 1996). This rate case Order is voluminous (more than 350 pages) and only makes limited reference to the ratepayer revenue for decommissioning. Thus, excerpts from this Order are provided in Attachment 2B. In relevant part, the Order found with respect to decommissioning expense and the ratepayer revenue to be collected: "[The Division of Ratepayer Advocates] reviewed Edison's cost studies for decommissioning SONGS and

Palo Verde and found them to be satisfactory for the purposes of developing Edison's test year 1995 nuclear decommissioning expense. No other party contests these expenses.").

Over subsequent years, site specific decommissioning cost studies for SONGS have been refined and the three cost categories that require funding in the NDTs have been clearly identified as: (1) license termination (10 CFR 50.75); (2) spent fuel management (10 CFR 50.54(bb)); and (3) site restoration. These cost studies have been reviewed and accepted by CPUC, and they have the formed the basis of CPUC Orders approving ratepayer revenue to fund the NDTs.

In addition to key excerpts from the 1993 TLG Study, Attachment 2A provides the cost summary tables for the three most recent studies that have been reviewed and approved by the CPUC, as well two further studies that are currently under review. The following Table identifies the site specific studies included in Attachment 2A and the related CPUC Order for each study.

Decommissioning Cost Study		**CPUC Order**		
Prepared By	**Date**	**Number**	**Date**	**Reference Pages**
TLG Services	June 1993	Decision 96-01-011	January 10, 1996	Pages 217-218
TLG Services	August 1998	Decision 99-06-007	June 3, 1999	Pages 8, 18-19, 21, 25
ABZ Inc.	October 2001	Decision 03-10-015	October 2, 2003	Pages 6, 30, 37, 38
ABZ Inc.	July 2005	Decision 07-01-003	January 11, 2007	Pages 16, 30-34
ABZ Inc.	February 2009	Decision 10-07-047	July 29, 2010	Pages 2-3, 11, 24, 49, 55-56
ABZ Inc.	December 14, 2012	n/a	n/a	n/a
ABZ Inc.	July 11, 2013	n/a	n/a	n/a

The three most recent CPUC Orders noted above are provided in Attachment 2B in their entirety.

CPUC action is pending regarding the review of the more recent cost studies. SCE expects specific CPUC action in connection with the Advice Letter process to identify the trust balances available for each of the three key cost categories based upon the July 2013 ABZ Study and the July 31, 2013 trust balances.

ATTACHMENT 2A

DECOMMISSIONING COST STUDY

for the

SAN ONOFRE
NUCLEAR GENERATING STATION

Prepared for the

SOUTHERN CALIFORNIA EDISON COMPANY

June 1993

TLG SERVICES

4.3 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impact of these considerations identified below is included in this cost study.

4.3.1 Spent Fuel Disposition

The 207 spent fuel bundles stored in the Unit 1 spent fuel pool will be transferred to dry spent fuel storage, or transferred to Unit 2 and/or 3 for storage in their respective spent fuel pools. This should occur by 1997 and, therefore any costs for wet storage of fuel are not necessary. Units 2 and 3, since decommissioning commences upon their final shutdown, must include the continued cost of wet storage of the final three fuel cycles until each cycle has decayed for at least five years from reactor core discharge. The five years is needed to permit the heat generation rate of the spent fuel assemblies to decay to acceptable levels for transportation and dry storage, typically 1kW per assembly. The decommissioning scenario has been constructed to permit continued operation of the Fuel Handling Buildings of Units 2 and 3. Once the final core discharge spent fuel assemblies have been placed in dry storage, the Unit 2 and 3 spent fuel storage and handling facilities are released for decommissioning.

SCE provided TLG with capital costs for construction, yearly maintenance costs, and final decommissioning and demolition costs for the dry spent fuel storage facilities.

4.3.2 Major Component Removal

The reactor pressure vessel and reactor internal components are segmented for disposal and shipped in shielded casks. Segmentation and packaging of the internals packages is performed in the refueling cavity where a turntable and remote cutter will be installed. The vessel is segmented in place using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the canal. The vessel and internals cutting equipment will be used in all three units. Shipping cask specifications and United States Department of Transportation (US DOT) regulations will dictate segmentation and packaging methodology; all packages designated meet current physical and radiological limitations and regulations. All cask shipments are made in US DOT-approved, currently available, truck casks. Both the closure head and the reactor vessel lower head are disposed of intact. These components are modified for shipment as their own containers and shipped to the burial site with the steam generators, reactor coolant pumps and pressurizer. The reactor internals classified as 10 CFR 61 "Greater than Class C," will be stored in dry storage spent fuel casks on-site until the WMS or other high-level waste repository takes possession of the GTCC waste.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and shipped by shielded van.

The Unit 1 steam generators cannot be removed with the existing reactor building crane. Portions of the external shield structure will be removed and the top of the containment dome lifted away in order to provide exterior access by a heavy-duty ringer crane or equivalent. Once outside the containment structure, the generators are moved to a temporary staging area on-site. Concrete grout is pumped into the generator to control movement of radioactive contamination during transport, and for radiation shielding. Additional carbon steel shields will be welded onto the outer surface of the steam generator as required to meet transportation requirements. Impact limiters will be placed on the generator package to provide protection against possible accidents during rail transport. The generators are then prepared and moved off-site by overland transporter to high-capacity railcars. These railcars transport the generators (and other NSSS components) to the burial site. This study assumes that the burial site has reasonable rail access for handling these high-capacity railcars.

The Unit 2 and 3 steam generators are assumed to be removed as follows: an auxiliary trolley placed on the Units 2 and 3 Reactor Building polar crane rail is used in conjunction with an elevated runway with a trolley outside the equipment hatch to extract the generators. The equipment hatch may be enlarged, or a secondary opening created, to accommodate removal of the generators. The upper steam dome will be segmented from the lower shell at the transition cone lower girth weld and removed separately from containment. A steel end cap will be placed over the exposed U-tubes in the lower shell of the steam generator, welded and non-destructively examined to meet transportation requirements. Once outside the containment structure, the generators are moved to a temporary staging area on-site. Concrete grout is pumped into the generator to control movement of radioactive contamination during transport, and for radiation shielding. Additional carbon steel shields will be welded onto the outer surface of the steam generator as required to meet transportation requirements. Impact limiters will be placed on the generator package to provide protection against possible accidents during rail transport. The upper steam dome will be segmented into pieces sized for packaging in high-weight capacity LSA boxes. The steam separators and dryers will also be segmented for packaging in high-weight capacity LSA boxes. The generators are then prepared and moved off-site by overland transport to a railhead for transfer to high-capacity railcars. These railcars transport the generators (and other NSSS components) to the burial site. This study assumes that the burial site has reasonable rail access for handling these high-capacity railcars.

The main turbine is dismantled using conventional maintenance procedures. The turbine rotors and shafts are removed to a clean laydown area for disposal. The lower turbine casings are removed from their anchors by controlled demolition. The main condensers are segmented and transported to the laydown area for disposal as scrap along with the lower turbine casings.

4.3.3 Transportation Methods

TLG assumed that the NSSS components (except for those containing GTCC material) are moved by a combination of overland transporter and rail to the regional burial facility. These payloads include the reactor vessel head packages, reactor coolant pumps, the steam generators and the pressurizer units. In this study it is assumed that the steam generator units are removed sequentially and stored on-site in a temporary staging area. The generators are then rigged for loading onto the transports.

All GTCC material is assumed to be transported by DOE to the WMS repository.

4.3.4 Site Conditions at Facility Closeout

It is assumed that the site is restored by regrading to conform to the adjacent landscape. Soil matching that of the adjacent landscape is brought on-site and placed to allow growth of native vegetation and drainage. The intake structures on-site will be demolished and removed, the circulating water conduits dredged and removed, and the underground piping on-site excavated and removed and the depressions backfilled. No subsurface structures will remain.

4.3.5 Land Ownership

The land upon which the SONGS Units are constructed is not owned by SCE. It was leased from the U.S. Government with a lease agreement that states SCE will remove vestiges of the site after station retirement. This requires the removal of all subsurface structures and systems, which is unique to the SONGS site when compared to the rest of the country.

4.4 ASSUMPTIONS

The following are the major assumptions made in the development of the cost estimates for SONGS.

1. SCE will hire a Decommissioning Operations Contractor (DOC). The DOC will provide sufficient staff to perform the preparatory demolition planning and scheduling, and manage the demolition efforts. Site security, health physics, quality assurance and overall site administration during decommissioning and demolition is provided by SCE. The demolition work is performed by the DOC, or a demolition subcontractor who will provide adequate staff, labor, equipment, materials and overhead to complete the demolition.

2. Only existing site structures and those presently in the construction stage are considered in the dismantling cost. Tentative designs and future site improvements are not considered.

3. A burial facility was assumed to exist at Ward Valley. This location was taken as the final destination for all radioactive waste shipments from SONGS. The cost of burial at this yet-to-be-developed site was based upon information supplied by SCE

4. No plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period, i.e., there is no significant reduction in waste volume in delaying decommissioning.

TABLE 8.1

SUMMARY OF DECOMMISSIONING COSTS

Work Category	Costs (thousands)	Percent of Total Costs
Unit 1 SAFSTOR		
Decontamination	6,057	2.24
Removal	56,177	20.74
Packaging	4,819	1.78
Shipping	4,283	1.58
Burial (off-site)	48,177	17.78
Decommissioning Staffs	74,238	27.40
Dry Cask Storage Costs	29,597	10.93
Other *	47,557	17.55
Subtotal	**270,905**	**100.00**
Unit 2 DECON		
Decontamination	16,299	2.69
Removal	124,844	20.62
Packaging	9,346	1.54
Shipping	7,082	1.17
Burial (off-site)	65,191	10.77
Decommissioning Staffs	154,112	25.46
Dry Cask Storage Costs	96,999	16.02
Other *	131,491	21.72
Subtotal	**605,364**	**100.00**

Document S03-25-003

TABLE 8.1

SUMMARY OF DECOMMISSIONING COSTS
(continued)

Work Category	Costs (thousands)	Percent of Total Costs
Unit 3 DECON		
Decontamination	25,285	3.45
Removal	190,532	26.03
Packaging	9,280	1.27
Shipping	7,049	0.96
Burial (off-site)	69,275	9.46
Decommissioning Staffs	176,779	24.15
Dry Cask Storage Costs	96,999	13.25
Other *	156,909	21.43
Subtotal	**732,108**	**100.00**
Station Total (with contingency)	**1,608,376**	

* Other includes: engineering & preparations, property lease payments, insurances, off-site LLW recycling costs and plant energy budget.

Document S03-1282-002

DECOMMISSIONING COST STUDY
for the
SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3

prepared for

Southern California Edison

August, 1998

prepared by

TLG Services, Inc.

Bridgewater, Connecticut

- Regulatory changes, e.g., affecting worker health and safety, site release criteria, waste transportation, and disposal.

- Policy decisions altering federal and state commitments, e.g., in the ability to accommodate certain waste forms for disposition, or in the timetable for such.

- Pricing changes for basic inputs, such as labor, energy, materials, and burial. Some of these inputs may vary slightly, e.g., 10% to +20%; burial could vary from -50% to +200% or more.

It has been TLG's experience that the results of a risk analysis, when compared with the base case estimate for decommissioning, indicate that the chances of the base decommissioning estimate's being too high is a low probability, and the chances that the estimate is too low is a much higher probability. This is mostly due to the pricing uncertainty for burial, and to a lesser extent, from schedule increases caused by changes in plant conditions, and variations in the cost of labor (both craft and staff).

3.4 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impact of the considerations identified below is included in this cost study.

3.4.1 Spent Fuel Disposition

This study does not address the cost of removal or disposal of spent fuel from the site. The cost for such activities is assumed to be covered under the 1 mill/kWhr surcharge SCE is paying to the DOE. However, this study does consider the constraints that the presence of spent fuel on site may impose on other decommissioning activities. Including the cost of storing spent fuel in this study is the most reasonable approach for rate making purposes, at this time. By including this cost, its insures the availability of sufficient decommissioning funds at the end of the station's life, if the DOE does not begin accepting spent fuel under their current obligations. For the basis of this cost study the transfer of spent fuel to the DOE is assumed to be to completed by the year 2050.

An ISFSI facility is assumed to exist in support of the SONGS 1 Decommissioning Project. Upon the station's shutdown, the ISFSI will be expanded to accommodate the additional casks in support of decommissioning. The spent fuel assemblies from the storage pool will be relocated to the ISFSI for storage within 66 months of final shutdown until such time that a transfer to a DOE or interim storage facility can be completed. Costs are included within the estimate for capital expenditures to expand the existing ISFSI, and the additional cask overpacks required to support decommissioning. Costs are included to operate the facility throughout the termination of the Part 50 license and until all the spent fuel is successfully transferred to the DOE.

3.4.2 Reactor Vessel and Internal Components

The reactor pressure vessel and reactor internal components are segmented for disposal in shielded transportation casks. Segmentation and packaging of the internals' packages are performed in the refueling canal where a turntable and remote cutter will be installed. The vessel is segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor cavity. Transportation cask specifications and Department of Transportation (DOT) regulations dictate segmentation and packaging methodology. All packages must meet the current physical and radiological limitations and regulations. Cask shipments will be made in DOT-approved, currently available, truck casks.

The dismantling of reactor internals will generate radioactive waste generally unsuitable for shallow land disposal (GTCC). Although the material is not classified as high-level waste, the DOE has indicated it will accept title to this waste for disposal at the future geologic repository (Ref. 11). However, the DOE has not yet established an acceptance criteria or a disposition schedule for this material, and numerous questions remain as to the ultimate disposal cost and waste form requirements. As such, for purposes of this study, the GTCC waste has been packaged and disposed of as high-level waste, at a cost equivalent to that envisioned for the spent fuel. Costs are included within the estimate for three ISFSI spent fuel casks for each unit to accommodate the GTCC material.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and shipped by shielded van. The reactor coolant pumps and motors are lifted out intact, packaged, and transported for disposal.

3.4.3 Steam Generators and Primary Coolant System Components

The steam generators' size and weight, as well as their configuration and limited access in the Reactor Building itself, place constraints on the intact removal of these components. Determination of the removal strategy requires several different considerations. Considerations for the extraction process include modifications to the Reactor Building for removal of the two generators, rigging needed to maneuver and extract the generators from the structure, and the component preparations needed to transport the generators to a disposal site.

A potential method for removal (and the one used as the basis in this estimate) is the extraction of the generators through a hatch created in the side of the Reactor Building. Sections of concrete are removed to create an opening large enough to extract the steam generators from the building. Removal of sections of the steam generator cubicle walls, adjoining floor slabs, and floor grating must also be accomplished to allow for the generators to be maneuvered to the opening. Grating within the work area will be decontaminated and removed.

Due to dimensional limitations for rail shipping, each generator will require that the steam dome be removed from the lower shell and tube bundle. This will be done in place in the Reactor Building using a track-mounted plasma-arc torch. A trolley crane will be set up for removal of the segmented generators. By setting the trolley crane before the generator segmentation, it can be used to remove portions of the steam generator cubicle walls and floor slabs out of the Reactor Building where they can be decontaminated and transported to the material handling area for concrete reprocessing.

The generators will be rigged for removal, disconnected from the surrounding piping and supports, then segmented. After segmentation, each piece will be maneuvered into the open area where they will be lowered onto a dolly. The dolly will allow the bottom end of each steam generator piece to rotate through the opening as it is being lowered. Once each section of steam generator has been lowered to the horizontal position each piece will be placed onto a multi-wheeled transporter.

The steam domes will be moved to a cutting station set-up on site specifically to segment the dome into pieces small enough to fit into sea vans. The steam domes are assumed to have a low-level of contamination and they will be transported to an off-site recyclee vendor for processing. The lower shell of the generator will be moved to an on-site storage area to await transport to the disposal facility. Once at the storage area, a new structural member will be welded onto the lower shell unit to provide containment for the tube bundle. The lower shell unit will have a carbon steel membrane welded to its outside surface for shielding. It is assumed that the lower shell can then be classified as an Industrial Package. Each lower shell of the generator will be loaded onto a multi-wheeled transporter and loaded onto a rail car. The generator-transporter package will be secured to the rail car for transport to the Ward Valley disposal facility. Once at the facility the generator will be grouted to satisfy burial ground packaging requirements.

The pressurizer will be removed in one piece using the same technique. The dimensions of the pressurizer will allow intact rail transport to the burial facility.

3.4.4 Transportation Methods

For the purpose of the cost estimate, it was assumed that the low-level radioactive waste produced and destined for controlled disposal will be moved overland by truck or shielded van to a licensed burial facility. The destination selected as the basis for the estimate transportation costs was Ward Valley, California. Transportation of the waste to a recycling center was assumed to be Oak Ridge, Tennessee for estimating purposes.

3.4.5 Low-Level Waste Disposal

The burial cost for disposal at the future regional radioactive waste disposal facility for the Southwest Compact was based upon projects available from US Ecology, the site developer and intended operator. An average disposal cost of $957.61 per cubic foot (supplied by SCE) was used in this estimate.

To the greatest extent practical, noncompactable LLW is treated to reduce the total volume of radioactive material requiring controlled disposal. The treated material meeting the regulatory and/or site release criteria is released as clean scrap, requiring no further cost consideration. Material not meeting release criteria will be processed for volume reduction and packaged for controlled disposal as radioactive waste. Material/waste recovery and recycling are assumed to be performed off site by a licensed processing center at a cost of $2.00 per pound.

Compactable DAW, such as booties, glove liners, respirator filter cartridges, shipping containers, radiological controls, survey materials, etc., will be assumed to be drummed and compacted to 10% of their original volume. This is the minimum practical volume to which LLW can be compacted to reduce costs.

3.4.6 Site Conditions Following Decommissioning

Following the decommissioning effort, the structures and remaining systems will meet the specified NRC site release limit. The NRC involvement in the decommissioning process typically will end at this point. Local building codes, state environmental regulations, and SCE's own future plans for the site will dictate the next step in the decommissioning process. TLG assumed the total removal of all plant systems and structures from the site, including all foundations and below grade structures to return the site to preconstruction conditions. These nonradiological costs are included within this study.

3.5 ASSUMPTIONS

The following are the major assumptions made in the development of the cost estimates for decommissioning SONGS 2/3.

3.5.1 Estimating Basis

1. The estimate is performed in accordance with the methodology described in the AIF/NESP-036 study.

2. Decommissioning costs are reported in the year of projected expenditure; however, the values are provided in 1998 dollars for the current estimate. Costs are not inflated or escalated over the period of performance.

3. Plant drawings, equipment and structural specifications, including construction details, were provided by SCE.

4. Only existing site structures and those presently planned will be considered in the decommissioning cost.

TABLE 6.1a

SUMMARY OF MAJOR COST CONTRIBUTORS:
DECON DECOMMISSIONING - UNIT 2

Work Category	Costs 98$ (Thousands)[1,2]	Percent of Total Costs[1]
Staffing	150,570	20.57
LLW Burial	140,617	19.21
Non-radiological Demolition	69,695	9.52
Removal	67,707	9.25
Staff Transition Costs	60,593	8.28
ISFSI Capital Expenditures	48,332	6.60
Remaining Costs[3]	40,984	5.60
Waste Recycling	28,897	3.95
Security Services	27,968	3.82
Decontamination	22,752	3.11
Lease Payments	17,008	2.32
Insurance	11,505	1.57
Hazardous Waste Disposal	10,617	1.45
Packaging	7,968	1.09
License Termination Survey	7,384	1.01
ISFSI Fees	6,428	0.88
Activity Specs. & Det. Procedures	4,254	0.58
NRC and EP Fees	3,645	0.50
Site Characterization Survey	2,506	0.34
Transportation	2,494	0.34
TOTAL	731,923	100.00

Notes:

1. Columns may not add due to rounding
2. All costs include contingency
3. Remaining costs include, building modifications, temporary services and support equipment.

TABLE 6.1b

SUMMARY OF MAJOR COST CONTRIBUTORS: DECON DECOMMISSIONING - UNIT 3

Work Category	Costs 98$ (Thousands)[1,2]	Percent of Total Costs[1]
Staffing	198,604	22.26
LLW Burial	154,345	17.30
Non-radiological Demolition	115,734	12.97
Removal	69,457	7.78
Staff Transition Costs	64,528	7.23
Remaining Costs[3]	58,382	6.54
ISFSI Capital Expenditures	48,332	5.42
Security Services	38,899	4.36
Waste Recycling	31,644	3.55
Decontamination	30,794	3.45
Lease Payments	16,745	1.88
License Termination Survey	14,637	1.64
Insurance	11,867	1.33
Hazardous Waste Disposal	10,592	1.19
Packaging	8,232	0.92
ISFSI Fees	6,376	0.71
Activity Specs. & Det. Procedures	4,254	0.48
NRC and EP Fees	3,690	0.41
Transportation	2,754	0.31
Site Characterization Survey	2,500	0.28
TOTAL	**892,366**	**100.00**

Notes:

1. Columns may not add due to rounding
2. All costs include contingency
3. Remaining costs include, building modifications, temporary services and support equipment.

SAN ONOFRE
NUCLEAR GENERATING STATION
UNITS 2 AND 3 (SONGS 2/3)

DECOMMISSIONING COST ESTIMATE

Prepared for

SOUTHERN CALIFORNIA EDISON COMPANY (SCE)
OCTOBER 2001

ABZ, INCORPORATED
4451 Brookfield Corporate Drive, Suite 101
Chantilly, Virginia 20151
(703) 631-7401

ABZ

WBS 4 Dry Storage/Fuel Transfer [728 weeks]:

- Activity Costs
  - All But Waste - $ 0
  - Waste Burial - $ 0
- Period Costs - $ 26404
- Staff Costs - $ 44205
- TOTAL (thousands) - $ 70609
  - License Termination Costs - $ 5775
  - Site Restoration Costs - $ 0
  - Fuel Storage Costs - $ 64834

WBS 5 Site Restoration [52 weeks]:

- Activity Costs
  - All But Waste - $ 5100
  - Waste Burial - $ 5157
- Period Costs - $ 4433
- Staff Costs - $ 5875
- TOTAL (thousands) - $ 20565
  - License Termination Costs - $ 428
  - Site Restoration Costs - $ 8411
  - Fuel Storage Costs - $ 11726

TOTAL DECOMMISSIONING COST - $ 1162262 (thousands)
- License Termination $ 722938 (thousands)
- Site Restoration Costs $ 245075 (thousands)
- Fuel Storage Costs $ 194250 (thousands)

TOTAL PERSONNEL DOSE - 1241 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 438231 cu·ft
  - CLASS B - 2708 cu·ft
  - CLASS C - 476 cu·ft
  - GTC - 1200 cu·ft
- WEIGHT - 55666109 pounds

CLEAN WASTE
- VOLUME - 6722194 cu·ft
- WEIGHT - 958851602 pounds

ABZ Incorporated
Decommissioning Cost Summary

UNIT 3 EOL S/D 2022 DECON

WBS 4 Dry Storage/Fuel Transfer [689 weeks]:

- Activity Costs
  - All But Waste - $ 0
  - Waste Burial - $ 0
- Period Costs - $ 25494
- Staff Costs - $ 41837
- TOTAL (thousands) - $ 67331
  - License Termination Costs - $ 5466
  - Site Restoration Costs - $ 0
  - Fuel Storage Costs - $ 61865

WBS 5 Site Restoration [52 weeks]:

- Activity Costs
  - All But Waste - $ 40980
  - Waste Burial - $ 13859
- Period Costs - $ 5215
- Staff Costs - $ 8632
- TOTAL (thousands) - $ 68686
  - License Termination Costs - $ 428
  - Site Restoration Costs - $ 55843
  - Fuel Storage Costs - $ 12415

TOTAL DECOMMISSIONING COST - $ 1215663 (thousands)
- License Termination $ 712077 (thousands)
- Site Restoration Costs $ 314677 (thousands)
- Fuel Storage Costs $ 188910 (thousands)

TOTAL PERSONNEL DOSE - 1303 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 462401 cu·ft
  - CLASS B - 2708 cu·ft
  - CLASS C - 476 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 56702483 pounds

CLEAN WASTE
- VOLUME - 10359493 cu·ft
- WEIGHT - 1423456225 pounds

SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3 (SONGS 2/3)

DECOMMISSIONING COST ESTIMATE

Prepared for

SOUTHERN CALIFORNIA EDISON COMPANY (SCE)

July 2005

ABZ, INCORPORATED
4451 Brookfield Corporate Drive, Suite 101
Chantilly, Virginia 20151
(703) 631-7401

ABZ

ABZ Incorporated
Decommissioning Cost Summary

UNIT 2 DECON - 2005 Update

TOTAL DECOMMISSIONING COST - $ 1508670 (thousands)
- License Termination $ 927274 (thousands)
- Site Restoration Costs $ 318816 (thousands)
- Fuel Storage Costs $ 262578 (thousands)

TOTAL PERSONNEL DOSE - 1241 rem

RADIOACTIVE WASTE 461905
- VOLUMES
  - CLASS A - 458721 cu·ft
  - CLASS B - 2708 cu·ft
  - CLASS C - 476 cu·ft
  - GTC - 1200 cu·ft
- WEIGHT - 57715109 pounds

CLEAN WASTE
- VOLUME - 6722194 cu·ft
- WEIGHT - 958851602 pounds

ABZ Incorporated
Decommissioning Cost Summary

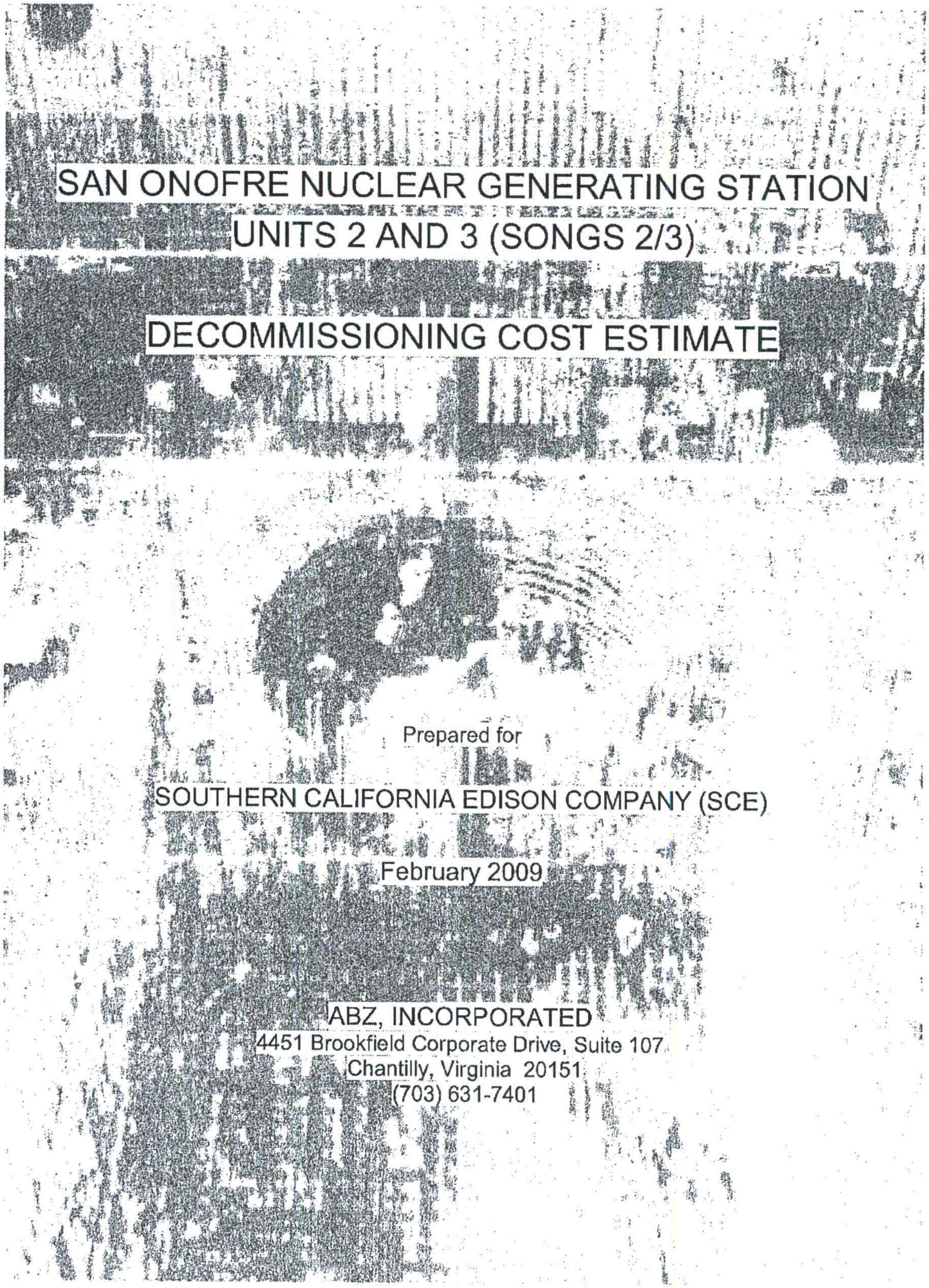
UNIT 3 DECON - 2005 Update

TOTAL DECOMMISSIONING COST - $ 1622092 (thousands)
- License Termination $ 926464 (thousands)
- Site Restoration Costs $ 436716 (thousands)
- Fuel Storage Costs $ 258912 (thousands)

TOTAL PERSONNEL DOSE - 1303 rem

RADIOACTIVE WASTE 465585
- VOLUMES
  - CLASS A - 462401 cu·ft
  - CLASS B - 2708 cu·ft
  - CLASS C - 476 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 56702483 pounds

CLEAN WASTE
- VOLUME - 10458146 cu·ft
- WEIGHT - 1438627751 pounds



SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3 (SONGS 2/3)

DECOMMISSIONING COST ESTIMATE

Prepared for

SOUTHERN CALIFORNIA EDISON COMPANY (SCE)

February 2009

ABZ, INCORPORATED
4451 Brookfield Corporate Drive, Suite 107
Chantilly, Virginia 20151
(703) 631-7401

ABZ

ABZ Incorporated
Decommissioning Cost Summary

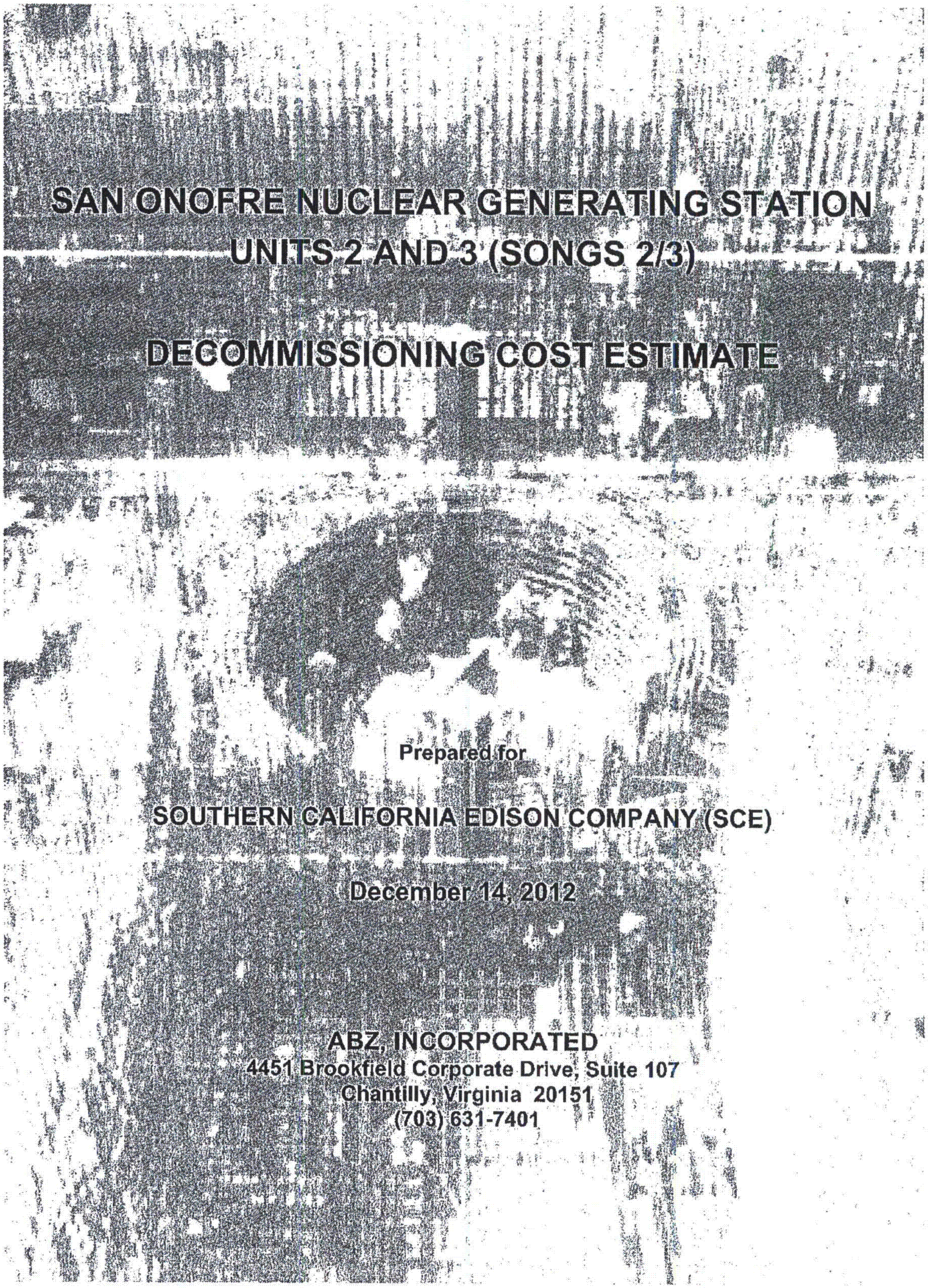
UNIT 3 DECON - 2008 Update

TOTAL DECOMMISSIONING COST - $ 1867898 (thousands)
- License Termination $ 1075602 (thousands)
- Site Restoration Costs $ 469413 (thousands)
- Fuel Storage Costs $ 322883 (thousands)

TOTAL PERSONNEL DOSE - 1145 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 748271 cu·ft
    - Bulk - 579242 cu·ft
    - General - 169029 cu·ft
  - CLASS B - 2708 cu·ft
  - CLASS C - 476 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 88825864 pounds

CLEAN WASTE
- VOLUME - 13256443 cu·ft
- WEIGHT - 1546411479 pounds



SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3 (SONGS 2/3)

DECOMMISSIONING COST ESTIMATE

Prepared for

SOUTHERN CALIFORNIA EDISON COMPANY (SCE)

December 14, 2012

ABZ, INCORPORATED
4451 Brookfield Corporate Drive, Suite 107
Chantilly, Virginia 20151
(703) 631-7401

ABZ Incorporated
Decommissioning Cost Summary

U2 2022 SD EARLY BLDG DEMO

TOTAL DECOMMISSIONING COST - $ 2003120 (thousands)
- License Termination $ 1005278 (thousands)
- Site Restoration Costs $ 366965 (thousands)
- Fuel Storage Costs $ 630876 (thousands)

TOTAL PERSONNEL DOSE - 1354 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 1811736 cu·ft
  - CLASS B - 3868 cu·ft
  - CLASS C - 1190 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 122757484 pounds

CLEAN WASTE
- VOLUME - 8680439 cu·ft
- WEIGHT - 1000998876 pounds

ABZ Incorporated
Decommissioning Cost Summary

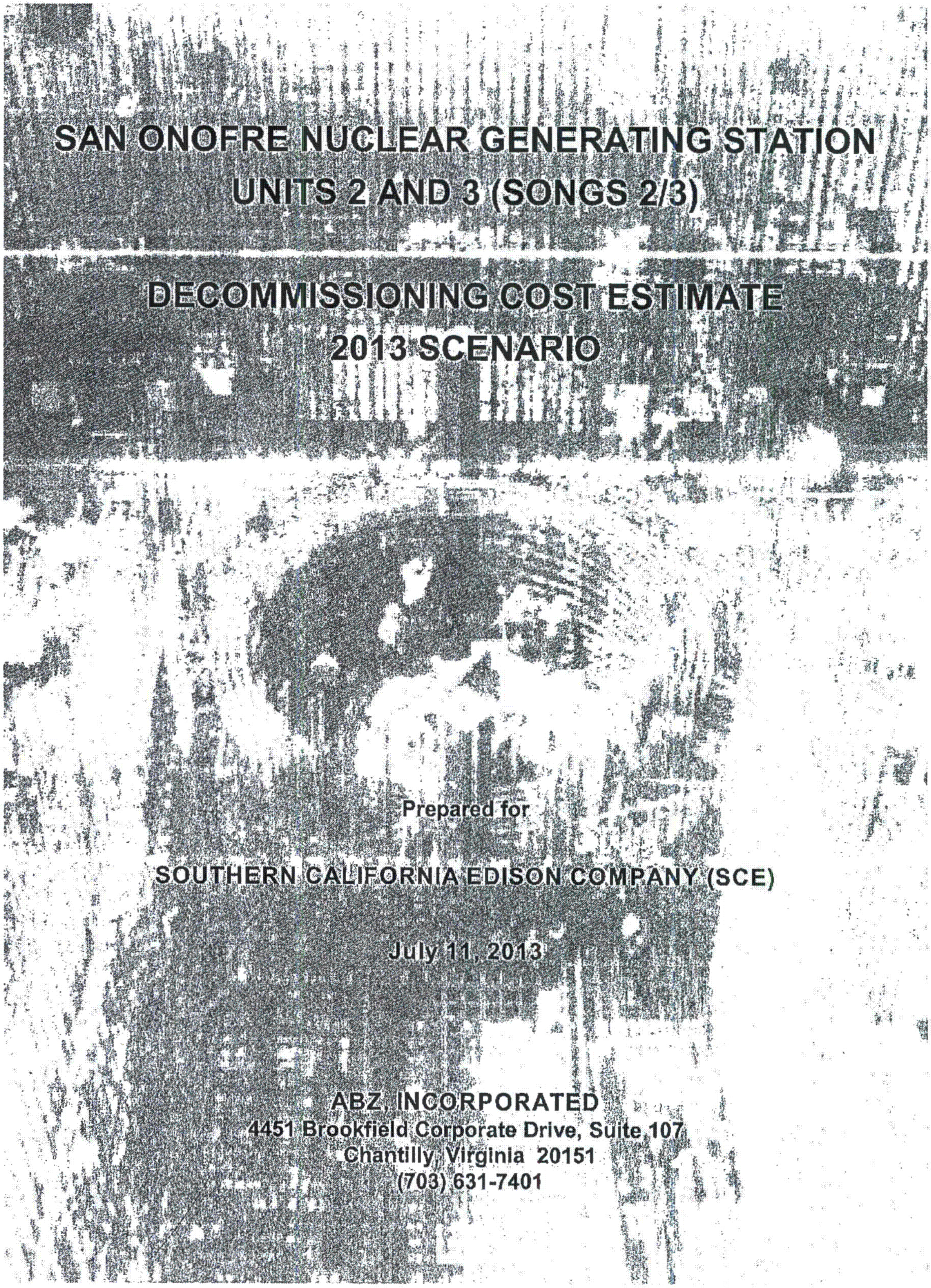
U3 2022 SD EARLY BLDG DEMO

TOTAL DECOMMISSIONING COST - $ 2115440 (thousands)
- License Termination $ 900633 (thousands)
- Site Restoration Costs $ 538503 (thousands)
- Fuel Storage Costs $ 676304 (thousands)

TOTAL PERSONNEL DOSE - 1346 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 1797677 cu·ft
  - CLASS B - 3868 cu·ft
  - CLASS C - 1190 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 121408401 pounds

CLEAN WASTE
- VOLUME - 12963659 cu·ft
- WEIGHT - 1510370707 pounds



SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3 (SONGS 2/3)

DECOMMISSIONING COST ESTIMATE 2013 SCENARIO

Prepared for

SOUTHERN CALIFORNIA EDISON COMPANY (SCE)

July 11, 2013

ABZ, INCORPORATED
4451 Brookfield Corporate Drive, Suite 107
Chantilly, Virginia 20151
(703) 631-7401

ABZ Incorporated
Decommissioning Cost Summary

U2 2013 START

TOTAL DECOMMISSIONING COST - $ 1972565 (thousands)
- License Termination $ 849547 (thousands)
- Site Restoration Costs $ 436725 (thousands)
- Fuel Storage Costs $ 686292 (thousands)

TOTAL PERSONNEL DOSE - 1303 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 1800489 cu·ft
  - CLASS B - 4539 cu·ft
  - CLASS C - 1641 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 121468172 pounds

CLEAN WASTE
- VOLUME - 8657002 cu·ft
- WEIGHT - 1000584146 pounds

ABZ Incorporated
Decommissioning Cost Summary

U3 2013 START

TOTAL DECOMMISSIONING COST - $ 2159777 (thousands)
- License Termination $ 829091 (thousands)
- Site Restoration Costs $ 606393 (thousands)
- Fuel Storage Costs $ 724291 (thousands)

TOTAL PERSONNEL DOSE - 1419 rem

RADIOACTIVE WASTE
- VOLUMES
  - CLASS A - 1794705 cu·ft
  - CLASS B - 3868 cu·ft
  - CLASS C - 1190 cu·ft
  - GTC - 1500 cu·ft
- WEIGHT - 120902969 pounds

CLEAN WASTE
- VOLUME - 12944709 cu·ft
- WEIGHT - 1510130515 pounds

ATTACHMENT 2B

COM/PGC/HMD

Decision 96-01-011 January 10, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Increase Its Authorized Level of Base Rate Revenue under the Electric Revenue Adjustment Mechanism for Service Rendered Beginning January 1, 1995 and to Reflect this Increase in Rates.	Application 93-12-025 (Filed December 27, 1993)
Order Instituting Investigation into the Rates, Charges, and Practices of SOUTHERN CALIFORNIA EDISON COMPANY, Establishment of the Utility's Revenue Requirement, and Attrition Request.	I.94-02-002 (Filed February 3, 1994)

(See D.94-12-045 for appearances.)

(Additional Appearances)

Charles C. Read, Attorney at Law, for Southern California Edison Company, applicant.
Glynnis Jones and Pete Price, for Appliance Recycling Centers of America, Inc.; Marc Joseph, Attorney at Law, for IBEW Local 47, UWUA Local 246; Steven Kotz, Attorney at Law, for California Cogeneration Council; and Sara Steck Myers, Attorney at Law, for the Center for Energy Efficiency and Renewable Technologies; interested parties.

that TURN's proposed adjustment is already reflected in the jurisdictional allocation of rate base to resale customers. Finally, Edison stated that TURN's recommendation is contrary to Standard Practice U-16, which was used by both Edison and DRA in determining their working cash estimates.

TURN argued that the Commission has indicated that U-16 needs revision and therefore will make exceptions to this Standard Practice in appropriate situations. (See e.g., California Water Service Company, D.93-01-025, 47 CPUC2d 580, 593; D.93-12-043, slip op. at p. 87.) However, we are concerned about Edison's assertions that TURN's proposed adjustment is already reflected in the jurisdictional allocation of rate base to resale customers. Because we wish to avoid "double-counting" reductions, we deny TURN's request on this issue.

17.5 Nuclear Decommissioning Expenses

DRA reviewed Edison's cost studies for decommissioning SONGS and Palo Verde and found them to be satisfactory for the purposes of developing Edison's test year 1995 nuclear decommissioning expense. No other party contests these expenses.

Edison stated that it is required to file a revised Schedule of Ruling Amounts (SRA) with the Internal Revenue Service to reflect any changes in the amounts of nuclear decommissioning costs authorized in the utility's cost of service.[86] At the Update hearings, Edison stated that it was advised after the close of the evidentiary hearings that when filing for future SRAs, the Internal Revenue Service now requires unit-specific information on

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86 According to Edison, a SRA is a levelized schedule of annual amounts that represent trust fund contributions required to fund the portion of the total estimated cost of decommissioning attributable to the remaining life of the nuclear power plant at the time that a decommissioning fund is initiated.

decommissioning costs from the utility's most recent cost of service proceeding such as this general rate case. Edison was also advised that the Internal Revenue Service finds it helpful if unit-specific information is included in the final decision. Edison submitted the following unit specific-information which no party objected to and which we adopt. (See Exhibit 169 at Appendix E, p. E-1.)

Line No.	Unit	Qualified ($000)	Nonqualified ($000)	Total ($000)	For Years
1.	SONGS 1	1,943	3,374	5,317	1995 - 2004
2.	SONGS 2	30,121	1,004	31,125	1995 - 2013
3.	SONGS 3	35,071	0	35,071	1995 - 2013
4.	PVNGS 1	9,250	0	9,250	1995 - 2024
5.	PVNGS 2	9,183	0	9,183	1995 - 2025
6.	PVNGS 3	9,876	0	9,876	1995 - 2027
7.	TOTAL	95,444	4,378	99,822	

17.6 Ratemaking Treatment of Fuel Inventory Carrying Costs

17.6.1 Positions of the Parties - Prior to the Settlement

Edison proposed that parts of its fuel oil, nuclear fuel, and coal inventories have permanent components which should be included in rate base and removed from ECAC treatment. What that means is that ratepayers would bear carrying costs for the fuel inventory deemed permanent at the rate of the weighted average cost of capital rather than the three-month commercial paper rate. Edison's specific proposal is that approximately $64 million of fuel oil, $73 million of nuclear fuel, and $5 million of coal be considered permanent and be rate based.

Edison defined permanent fuel inventories "to be the minimum amount that must be maintained over the long-term to assure continuing and reliable operations." (Exhibit 212 at p. 2.) In support of its proposal, Edison uses examples of tools, materials, and supplies that are rate based.

Decision 99-06-007 (June 3, 1999)

ALJ/JPO/mrj

Mailed 6/3/99

Decision 99-06-007 June 3, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of SOUTHERN CALIFORNIA EDISON COMPANY and SAN DIEGO GAS AND ELECTRIC COMPANY for the Nuclear Decommissioning Cost Triennial Proceeding to set Contribution Levels for the Companies' Nuclear Decommissioning Trust Funds and Address Other Related Decommissioning Issues.	Application 98-12-025 (Filed December 21, 1998)

Table of Contents

OPINION

Summary

In this decision we approve a settlement proposed by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), the Office of Ratepayer Advocates (ORA), and The Utility Reform Network (TURN). We authorize annual revenue requirements for contributions to the Nuclear Decommissioning Trust Funds (Trusts) of $25 million and $5 million for SCE and SDG&E respectively. We authorize the decommissioning of San Onofre Nuclear Generating Station Unit 1 (SONGS 1) and amendment of the Master Trust Agreements (MTAs) to facilitate timely availability of the funds to pay the costs of decommissioning. We also adopt the utilities' decommissioning cost estimates, authorize the utilities to retain tax benefits associated with SONGS 1 decommissioning, and authorize the utilities to continue collecting shutdown operations and maintenance (O&M) expenses for SONGS 1 until the spent fuel is put in dry storage. Additionally, we authorize a procedure for review of the costs incurred in decommissioning SONGS 1.

I. Background

On December 21, SCE and SDG&E (referred to jointly as Applicants) jointly filed Application (A.) 98-12-025. The purpose of the application was to set the contribution levels for Applicants' Trusts, and to address other related decommissioning issues.

On February 5, 1999, ORA and TURN filed protests of the application.

On February 9, 1999, Applicants served errata to the testimony filed with their application.

On February 16, 1999, Applicants filed a joint response to the protests.

On February 19, 1999, a prehearing conference was held.

On March 8, 1999, Applicants, ORA, and TURN filed a joint motion seeking adoption of a Settlement Agreement (Settlement). No comments on the Settlement were received.

II. Overview of the Application

By Ordering Paragraph 7 of Decision (D.) 95-07-055, we ordered Applicants to file their joint application for the first Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). This application complies with our order.

The purpose of the NDCTP is to set the contribution levels for Applicant's Trusts for the three year period beginning January 1, 2000. The Trusts are for Applicants' ownership shares of San Onofre Nuclear Generating Station Units 1, 2, and 3 (SONGS 1, 2, and 3) and Palo Verde Nuclear Generating Station Units 1, 2, and 3 (Palo Verde 1, 2, and 3). SCE owns 80% of SONGS 1 and 75.05% of SONGS 2 and 3. SCE is the operating agent. SCE is a non-operating owner of 15.8% of Palo Verde 1, 2, and 3. SDG&E owns 20% of SONGS 1, 2, and 3.

Applicants also requested authority to access the SONGS 1 Trusts in order to begin decommissioning SONGS 1. Applicants proposed that no further contributions to the SONGS 1 Trust are needed. Applicants further proposed a procedure to ensure cost-effective completion of SONGS 1 decommissioning.

III. Procedural Matters

In Resolution ALJ 176-3008, dated January 20, 1999 we preliminarily categorized this application as ratesetting and preliminarily determined that hearings would be necessary. In the Scoping Memo and Assigned Commissioner's Ruling, dated February 25, 1999, these determinations were confirmed. The scoping memo designated the assigned Administrative Law Judge (ALJ) as the principal hearing officer. Since the proposed Settlement is unopposed, we now determine that hearings are not necessary.

As a result of the settlement, this is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Pub. Util. Code § 311(g)(2), the otherwise applicable 30-day period for public review and comment is waived.

IV. The Application

We summarize the Applicants' request below.

A. Methodology for Calculating Trust Contributions

Applicants each have a qualified and a non-qualified master trust. Qualified trusts hold decommissioning funds that result from contributions that qualify for an income tax deduction under Section 468A of the Internal Revenue Code. Nonqualified trusts hold decommissioning funds that result from all other contributions. Within each master trust are separate trust accounts for each of the nuclear generating station units. All decommissioning funds for Palo Verde are held in a qualified trust.

The annual decommissioning contribution amount is determined using the following annuity calculation:

$$\text{Annual Expense} = [((QxC)\text{-}Pq) \times (Rq/(1+Rq)^{RL}\text{-}1)] + [((NxC)\text{-}Pn) \times (Rn/(1+Rn)^{RL}\text{-}1)],$$

where:

Q = qualified percent

C = total future cost to decommission in retirement year Dollars

Pq = qualified trusts liquidation market value as of 9/30/98 in retirement year dollars

Rq = qualified rate of return (%)

RL = remaining life of nuclear reactor (years)

N = nonqualified percent

Pn = nonqualified trusts liquidation market value as of 9/30/98 in retirement year dollars

Rn = nonqualified rate of return (%)

The key elements of the calculation are (1) the decommissioning cost estimate in current dollars, (2) the escalation of the decommissioning costs, and (3) the after-tax rates of return on the trusts. The decommissioning cost estimate and escalation are used to compute C, the total future costs of decommissioning.

B. Nuclear Decommissioning Cost Estimates

Applicants' nuclear decommissioning cost estimates, in 1998 dollars, were developed based on site specific studies performed by TLG Services, Inc. The estimates are as follows:

Line No.	San Onofre Nuclear Generating Station	100% Share, 1998 $ $ x 1,000	
1	Unit 1	458,772	367[illegible]
2	Unit 2	731,923	[illegible]
3	Unit 3	892,366	[illegible]
4	TOTAL	2,083,061	

Line No.	Palo Verde Nuclear Generating Station	SCE Share, 1998 $ $ x 1,000
1	Unit 1	107,082
2	Unit 2	112,372
3	Unit 3	129,363
4	TOTAL	348,817

U1 459,346

U2 438,713

U3 [illegible]

Applicants reconcile the decommissioning cost estimates to those in SCE's 1995 general rate case (GRC) as follows:

Applicants' Reconciliation of SONGS and Palo Verde Decommissioning Estimates 1998 Estimates vs. 1995 GRC

Line No.		Thousands of 1998 $		
		SONGS 1 (100% Share)	SONGS 2 & 3 (100% Share)	Palo Verde (SCE Share)
1	1998 Decommissioning Cost Estimate/Request	458,772	1,624,289	348,817
2	1995 GRC Decommissioning Cost Estimate	319,826	1,529,505	477,637
3	CHANGE	138,946	94,784	(128,820)
4	Reconciliation:			
5	Dismantling Activities	93,976	41,283	(6,817)
6	Post-Shutdown Spent Fuel Storage	44,520	(35,930)	12,525
7	Low-Level Radioactive Waste Burial	450	89,431	(72,275)
8	Contingency	Included Above	Included Above	(62,253)
9	CHANGE	138,946	94,784	(128,820)

1. SONGS 1

The SONGS 1 decommissioning cost estimate increased by $138,946,000 from the cost estimate in SCE's 1995 GRC. Approximately $93,976,000 of this increase is due to increased staffing and removal costs associated with a 20-month increase in the estimated duration of dismantling activities. In the 1995 GRC cost estimate, SCE estimated that the decontamination, removal, and disposal of all contaminated and non-contaminated SONGS 1 systems, components, structures, and buildings would be completed in 60 months.

The current cost estimate assumed that the decontamination, removal, and disposal of all contaminated and non-contaminated SONGS 1 systems, components, structures, and buildings would be completed in 80 months. The increase in the cost to perform the dismantling activities is due primarily to the increased staffing and removal cost requirements necessitated by the 20-month increase. These increased costs are attributable to TLG's revised cost estimating methodologies based on experiences gained at other nuclear decommissioning projects.

SCE attributes an additional $44,520,000 of the increase to the inclusion of construction and monitoring costs for a dry storage facility for SONGS 1 spent fuel. SCE did not include the cost to construct a dry storage facility for the SONGS 1 spent fuel, or to transfer the fuel from wet to dry storage, in its 1995 GRC cost estimate. Because the SONGS 1 spent fuel may remain onsite until at least 2024, failure to place all SONGS 1 spent fuel stored onsite into dry storage would inappropriately constrain and delay SONGS 1 decommissioning. SCE asserts that the cost to place all SONGS 1 spent fuel stored onsite into dry storage is, therefore, a necessary and appropriate decommissioning cost.

The $450,000 cost increase for Low Level Radioactive Waste (LLRW) burial is due to the increased burial cost at Ward Valley. The estimated decrease in the volume of SONGS 1 decommissioning LLRW requiring disposal partially offset the burial cost increase. The costs associated with decommissioning SONGS 1, excluding LLRW burial cost, include the application of a 40% contingency factor.

2. SONGS 2 & 3

The current SONGS 2 & 3 decommissioning cost estimate increased by $94,784,000 above the previous cost estimate. Nearly $41,283,000 of this increase is attributed to TLG's revised techniques for estimating the costs of dismantling activities.[1] The estimated duration of SONGS 2 & 3 dismantling activities is similar to the duration projected in previous estimates. These increased costs are attributable to TLG's revised cost estimating methodologies based on experience gained at other nuclear decommissioning projects.

The estimated cost to construct and monitor a dry fuel storage facility for SONGS 2 & 3 decreased by $35,930,000. This decrease is due primarily to improved information regarding dry storage costs. The estimated dry storage cost for the SONGS 2 & 3 spent fuel in the current SONGS 2 & 3 decommissioning cost estimate is less than the levels projected in the 1995 GRC decommissioning cost estimate due to industry experience acquired after that study was developed.

A cost increase of $89,431,000 is due to the estimated LLRW disposal cost, notwithstanding a decrease in the estimated volume of waste that will require burial.

3. Palo Verde

The Palo Verde decommissioning cost estimate decreased by approximately $128,820,000 from the 1995 GRC decommissioning cost estimate.

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[1] All SONGS site common expenses, including site lease payments, are included in TLG's 1998 SONGS 2 & 3 Decommissioning Cost Analysis.

This decrease is due primarily to a decrease of more than half of the volume of LLRW estimated to require disposal. Additionally a lower base burial charge was assumed. The other major source of the estimated cost decrease is the reduction from a 50% to a 40% contingency factor for the entire estimate. There was also a small decrease for dismantling activities. These decreases were offset by a small increase for post-shutdown spent fuel storage.

The 1998 Palo Verde Decommissioning Cost Study, which was prepared by TLG, was based on an assumption that the Department of Energy (DOE) would accept Palo Verde spent fuel at a much faster rate than the last schedule for accepting spent fuel published by the DOE. SCE believes there is no basis for assuming this faster rate. Therefore, SCE concluded that the Palo Verde spent fuel will remain in on-site dry storage at least until 2060 and included the cost to monitor dry fuel storage at Palo Verde until 2060 in this cost estimate.

C. Escalation

Applicants' annual escalation rates are used to convert the decommissioning cost estimates in 1998 dollars to future-year dollars. Separate escalation rates were used for labor, the combined category of material, equipment and other, and for burial.

Applicants' rates were based upon projections provided by Standard & Poor's (S&P's) DRI economic forecasting service. The projection used was the August 1998 TREND25YEAR0898 projection. The projection spans the period from 1998 through 2023. The 2023 rates were used after 2023.

For labor escalation, applicants used the DRI projection of the Employment Cost Index for total compensation, private sector. Applicants believe that this index is appropriate because it tracks changes in wages, salaries, and employee benefits free of the influence of employment shifts among occupations and industries.

For the combined category of material, equipment, and other, applicants constructed an index that is a weighted average of the following Producer Price Indexes.

Fuels related products and power	(PPI05)
Chemicals and allied products	(PPI06)
Metals and metal products	(PPI10)
Construction machinery and equipment	(PPI112)
General purpose machinery and equipment	(PPI114)
Other industrial commodities	(PPIINDO)

Applicants used DRI projections of PPI05, PPI06, PPI10, and PPIINDO directly. To estimate values for PPI112 and PPI114, applicants constructed an econometric forecasting model that related historical changes in PPI112 and PPI114 to the Producer Price Index for machinery and equipment (PPI11). Applicants produced a projection of PPI112 and PPI114 based on the DRI projection of PPI11.

Applicants calculated weighted averages of these indexes for each SONGS unit and the Palo Verde units using weights first used in OII-86 and in SCE's 1992 and 1995 GRCs.

Applicants used two statistical models to estimate annual burial escalation rates. The estimates were performed using historical trends in burial escalation costs published by the Nuclear Regulatory Commission (NRC). The historical burial escalation cost factors were for the period 1986 through 1997 for burial sites in Nevada, South Carolina, and Washington. The resulting estimates ranged from 7.3% to 11.6%. Applicants chose to use a 10% rate because of the possibility of large increases in the cost of burial.

D. Trust Rate of Return Estimates

In D.95-07-055 the Commission placed the following restrictions on Trust investments.

- Qualified Trusts

  Up to 50% may be invested in equities with a 20% limit on international equities.

  At least 50% of the equity investments must be invested passively.[2]

  Up to 100% of the funds may be invested in investment grade fixed income securities.[3]

- Nonqualified Trusts

  Same as for qualified Trusts except that up to 60% of the investments may be in equities.

Applicants based their estimates of future equity returns on DRI's August 1998 TREND25YEAR0898 projection. Specifically, applicants used the DRI variables for S&P's 500 Stock Price Index (JS&PNS) and the dividend yield for S&P's 500 Stock Index (JS&PYIELD).

Applicants represent that the DRI projections are reasonable because Gross Domestic Product (GDP) growth and bond yields will be lower in the future, and because equities are currently overvalued.

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[2] A passive investment strategy is one that seeks to match the return of a benchmark index, such as the S&P's 500 index, by replicating the composition of the index. D.95-07-055, Findings of Fact 12 and 13.

[3] Investment grade securities are those rated BBB – or higher by S&P's or equal to or higher than the equivalent rating by other rating agencies. D.95-07-055, Finding of Fact 9.

Applicants based their estimates of future fixed income security returns on the DRI August 1998 TREND25YEAR0898 projections of the following three variables.

- Discount Rate on three-month U.S. Treasury bills (RMGBS3NS).
- Yield on ten-year constant maturity U.S. Treasury bonds (RMGFCM@IONS).
- Moody's average yield on AAA state and local government bonds (RMAAAGSLNS)

Applicants reduced the DRI RMAAAGSLNS projection by 57 basis points because the benchmark fixed-income return for the nonqualified trusts is for bonds with a maturity of 10 years or less rather than the 20 years used in the projection. The 57 basis points reduction is the observed difference between the 20-year and ten-year Moody's AAA municipal bond rates for the period January 1, 1996 through November 13, 1998.

Applicant's projected average yields for the period 1998 through 2022 are 4.47% for three-month Treasury bills, 5.26% on ten-year Treasury bonds and 4.23% on AAA state and local government bonds.

E. Tax Rates and Investment Strategies

The tax rates and trust investment strategies used in Applicants' calculations are as follows:

Characteristic	Qualified Trust	Nonqualified Trust
Federal tax rate	20.00%	35.00%
State tax rate	8.84%	8.54% (SCE)/8.68% (SDG&E)
Equity portfolio turnover	Five percent annually	Five percent annually
Federal dividend exclusion	Zero percent	70 percent
Equity investment percentage (before liquidation)	50 percent	60 percent
Equity investment liquidation	2014 (SONGS) 2025/2026/2028 (Palo Verde)	2014
Fixed income asset	Ten-year Treasury bonds	AAA municipal bonds

Applicants' after-tax trust fund return estimates are as follows:

	Qualified Trust	Nonqualified Trust
SONGS 1998-2013	4.83 percent	4.68 percent
SONGS 2014+	4.06 percent	3.88 percent
Palo Verde 1998-2024/2025/2027	4.84 percent	(Not applicable)
Palo Verde 2025+/2026/2028+	4.06 percent	(Not applicable)

F. Contributions and Revenue Requirements

Applicants' requested annual revenue requirements are as follows:

Proposed Nuclear Decommissioning Recovery For SONGS 1, SONGS 2 & 3 And Palo Verde (SCE Share) ($ x 1000)

Line No.	Description	1995 GRC Authorized	2000 Estimated
1	Estimated Costs (1998 Dollars)	2,224,682	1,934,863
2	Estimated Costs (Future Dollars)	12,736,728	8,608,977
3	Fund Liquidation Value (as of 9/30/98)	1,869,502	1,869,502
4	Remaining Liability	10,867,226	6,739,475
5	Annual Contribution	99,822	40,694
6	Annual Revenue Requirement	104,426	41,559

Proposed Nuclear Decommissioning Recovery For SONGS 1, and SONGS 2 & 3 (SDG&E Share) ($ x 1000)

Line No.	Description	1993 GRC Authorized	2000 Estimated
1	Estimated Costs (1998 Dollars)	381,123	416,612
2	Estimated Costs (Future Dollars)	1,264,196	1,360,872
3	Fund Liquidation Value (as of 9/30/98)	413,475	413,475
4	Remaining Liability	850,721	947,397
5	Annual Contribution	22,038	7,287
6	Annual Revenue Requirement	30,133	7,411

G. SONGS 1 Decommissioning

Applicants request authority to begin decommissioning SONGS 1 in 2000. They cite the following four reasons:

- Reduced customer costs associated with decommissioning work, especially low level radioactive waste burial costs.
- Reduced costs due to such things as labor cost, escalation, and changing regulatory requirements.
- Safe decommissioning technologies are available now.
- Availability of former SONGS 1 workers at the SONGS site.

H. Reasonableness of SONGS 1 Decommissioning Expenditures

Applicants propose the following procedure to ensure the reasonableness of decommissioning expenditures. Applicants will provide annual advice letter filings that forecast the planned work and related costs for the upcoming year. They will also provide the recorded costs for the previous year. If cost increases arise due to changed circumstances, applicants would file supplemental advice letters. Applicants propose that, if recorded costs for any given year do not exceed the forecasts by more than 20%, the costs should be presumed reasonable. Any party claiming that Applicants' actions are unreasonable when the costs are within the 120% level, would bear the burden of demonstrating unreasonableness.

Applicants further propose that, within 6 months of completion of all decontamination, dismantling, and dry fuel storage, they would file an advice letter summarizing total recorded costs, and estimated costs of dry fuel storage monitoring, license termination, and final site restoration, as well as remaining trust fund balances.

Applicants represent that their proposal is reasonable since traditional reasonableness reviews are for major rate base additions and, in this case, no addition is involved.

I. Maintenance Costs for SONGS 1 Wet Fuel Storage

Applicants propose that the costs for wet fuel storage continue to be collected in rates as shutdown O&M costs until the fuel is moved to dry storage. Applicants represent that the current decommissioning cost estimate does not include direct or common costs for wet fuel storage prior to 2004. These costs will continue to be incurred until the fuel is put in dry storage. When the fuel is moved to dry storage, the costs for dry storage will be paid from the trust funds.

Applicants currently expect to transfer the fuel to dry storage in 2004 or 2005. If the transfer to dry storage takes place after 2004, applicants propose to immediately refund dry storage monitoring costs to customers beginning in 2004 until the fuel is put into dry storage.

J. Tax Benefits Resulting from Non-qualified Fund Expenditures

Contributions to non-qualified Trusts are not immediately deductible. Therefore, the amounts collected were increased to cover applicable taxes. When the funds are withdrawn from the trust, there is no tax deduction available. However, there is an available tax deduction for the decommissioning costs expended. The result is a net decrease in taxes when the expenditures are made. The one exception is that the costs for the dry fuel storage facility may have to be depreciated over the life of the facility as opposed to being expensed. An Internal Revenue Service (IRS) ruling will be needed in order to resolve this uncertainty. The tax benefits can either be refunded to ratepayers or used to fund decommissioning work.

Applicants propose that the tax benefits be kept in the Trusts to pay for decommissioning work. Applicants believe their proposal is reasonable because it would reduce the need for additional ratepayer contributions if the Trust balances turn out to be insufficient, and it will give the Trust Investment Committees the opportunity to earn a higher return for the Trust.

K. Finance Charges for Delays in Trust Fund Withdrawals

The Master Trust Agreements specify procedures for payment of decommissioning costs. As a result, there will be instances where applicants will have to make payments prior to receiving the funds from the Trust. This results in a financing cost to applicants.

Applicants represent that since these financing costs result from decommissioning, they should be recovered from the Trust. Applicants propose that the financing cost be calculated as the decommissioning cost amount times the 90-day commercial paper rate times the time lag between payment and receipt of funds from the Trust.

Applicants offer as an alternative that the Master Trust Agreements be amended to provide for faster payment. An amendment would require approval by the Decommissioning Trust Committees and the Commission.

V. The Proposed Settlement

The following are the key elements of the Settlement proposed by Applicants, ORA, and TURN (Proponents)

- SCE and SDG&E should be authorized to recover annual revenue requirements of $25 million and $5 million, respectively, for contributions to their Trusts. The effective date of the revenue requirement change should be the effective date of the Commission's approval of the Settlement or as soon as possible thereafter.
- The Commission should find the allocations of the annual revenue requirements between the nuclear generating units in Appendices B and C to the Settlement reasonable.
- The Commission should adopt Applicants' decommissioning cost estimates for their nuclear generating units.
- Applicants should be authorized to access their SONGS 1 Trusts for the purpose of commencing SONGS 1 decommissioning work on the effective date of Commission adoption of the settlement or as soon as possible thereafter.

- The Commission should review SONGS 1 decommissioning work every three years through Applicants' NDCTP applications. Based on these applications, the Commission would make findings about the reasonableness of costs incurred and work completed during the 3-year period. These findings of reasonableness would not be subject to further review.
- Applicants should retain the tax benefits associated with the use of their SONGS 1 nonqualified Trusts until completion of Phase I of SONGS 1 decommissioning work. Upon completion of Phase I, Applicants will assess the remaining SONGS 1 decommissioning work and recommend to the Commission the appropriate timing for returning the nonqualified Trust tax benefits to ratepayers.
- Applicants may continue collecting shutdown O&M expenses for SONGS 1 until SONGS 1 spent fuel is removed from the SONGS 1 spent fuel pool and placed in dry storage. Applicants will seek regulatory approval for the transfer of the spent fuel to dry storage in a timely manner.
- The Commission should amend the Applicants' Master Trust Agreements to enable advance withdrawals from the Trusts. This will eliminate the need for financing the costs of the lag between when decommissioning costs are paid and when reimbursements from the Trusts are made.

VI. Proponents' Explanation of the Settlement

A. Nuclear Decommissioning Trust Contributions

Applicants initially requested to decrease the currently authorized annual revenue requirements from $104,426,000 and $30,133,000 to $47,480,000 and $7,411,000 for SCE and SDG&E respectively. Subsequently, SCE revised its request to $41,559,000 due to more recent information on the decommissioning cost for Palo Verde and due to elimination of an error in the initial calculation. As explained in the testimony in support of the settlement agreement, the proposed annual revenue requirement was further adjusted to update the Trust values to December 31, 1998 and to advance the assumed date of the changes in contribution levels to July 1, 1999. This results in a annual revenue requirement of $34.7 million and $6.1 million, for SCE and SDG&E respectively.

Under the terms of the Settlement, Proponents agreed to annual revenue requirements of $25 million and $5 million for SCE and SDG&E respectively. Proponents settled on these values. They did not settle on specific underlying assumptions. Proponents believe that these values are reasonable for the next three years. Proponents also stated that they will take a fresh look at all of the variables in the next NDCTP in 2001.

B. SONGS 1 Decommissioning

Under the terms of the Settlement, Proponents support commencement of SONGS 1 decommissioning as of the effective date of a decision in this proceeding. Proponents also requested that Applicants be authorized to have access to trust funds equal to 90% of the Commission's most recently adopted SONGS 1 decommissioning cost estimate in order to conduct the decommissioning.

1. SONGS 1 Reasonableness Review

Proponents have agreed that the reasonableness of incurred decommissioning costs would be examined in the NDCTP. Applicants would report on the status of the decommissioning work, and the costs incurred to date, as part of their application. The reasonableness review would be conducted in a manner similar to those conducted in the Energy Cost Adjustment Clause reviews. If the costs incurred are within the most recent cost estimate approved by the Commission based on the scope of work completed, the costs and conduct would be presumed reasonable. Any entity claiming unreasonable costs or actions would bear the burden of proof. Applicants would bear the burden of proving that any material increase in costs for the scope of work are reasonable.

As part of the application, Applicants would also submit an updated decommissioning cost estimate that describes the remaining scope of work, updated assumptions for escalation rates and other variables, and a forecast of the amount remaining in the SONGS 1 Trusts.

2. SONGS 1 Nonqualified Trust Tax Benefits

Under the terms of the Settlement, Applicants will retain the tax benefits until Phase I of SONGS 1 decommissioning (decontamination, dismantling, and dry fuel storage implementation) is complete.[4] Applicants will then recommend to the Commission the appropriate timing for returning the tax benefits to customers. This will allow a more accurate assessment of whether there are sufficient funds to complete the remaining decommissioning work.

3. Collection of SONGS 1 Shutdown O&M Expenses

Under the terms of the Settlement, Applicants will continue to collect SONGS 1 shutdown O&M expenses until SONGS 1 spent fuel is placed in dry storage. Applicants are currently collecting these expenses as authorized in D.96-01-011 and D.92-12-019, the 1995 and 1993 test year general rate case decisions for SCE and SDG&E respectively.

C. Finance Charges for Delays in Trust Fund Withdrawals

Under the terms of the Settlement, Proponents agree that the Master Trust Agreements should be amended to enable advance withdrawals from the Trust Funds to recover expected decommissioning costs. Proponents request that the Commission order Applicants to amend their Master Trust Agreements accordingly.

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[4] The three phases of decommissioning SONGS 1 are (1) decontamination, dismantling, and dry fuel storage implementation, (2) dry fuel storage monitoring, and (3) license termination and final site restoration.

VII. Commission Approval of the Settlement

Proponents state that the Settlement, taken as a whole, is fair, reasonable, and in the public interest. They also state that the Settlement satisfies Rule 51.1(e) of our Rules of Practice and Procedure.

Rule 51.1(e) is as follows:

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

A. Proponents Position

Proponents stipulate to all the following materials being entered into the formal record in this proceeding without evidentiary hearings: (1) Applicants' testimony, (2) the Settlement, and (3) the Testimony Supporting the Settlement Agreement. Proponents believe that these materials and the joint motion contain the information necessary for the Commission to find the Settlement reasonable in light of the record.

Proponents believe that the terms of the Settlement comply with all statutes and prior Commission decisions.

Proponents believe that the Settlement is a reasonable compromise of their respective positions. Proponents fairly reflect the interests affected by the Applicants' application. Proponents represent Applicants, the long term interests of all California customers (ORA), and the interests of residential and small commercial customers (TURN). Proponents believe the Settlement is in the public interest and in the interest of Applicants' customers.

Proponents believe that the Settlement avoids the cost of litigation, and frees the Commission's resources for other proceedings. The Settlement frees the time and resources of other parties as well, so that they may focus on other proceedings of interest. Proponents believe that the Settlement process is also better suited and more efficient than traditional litigation in this proceeding.

Proponents stated that each portion of the Settlement is interdependent upon the other, and that they believe that no single issue should be evaluated in isolation from the rest of the Settlement. Changes in one portion of the Settlement would alter the balance of interests and the mutually agreed upon compromises and outcomes which are contained in the Settlement. As such, Proponents requested that it be adopted as a whole, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

B. Discussion

We will review the proposed Settlement using the criteria contained in Rule 51.1(e). Additionally, we will keep in mind the four-part test the Commission adopted for all party settlements in D.92-12-019 (in Re: San Diego Gas & Electric (SDG&E) (1992) 46 CPUC2d 538). Under the test the Settlement must:

1. Command the unanimous sponsorship of all active parties in the proceeding;
2. Have parties which are fairly reflective of the affected interests;
3. Not propose terms which contravene statutory provisions or prior Commission decisions; and
4. Convey sufficient information to permit the Commission to discharge its future regulatory obligations regarding the parties and their interests.

First we will apply the four-part test.

The Settlement is sponsored by Applicants, ORA, and TURN. The other two parties to this proceeding are Pacific Gas and Electric Company (PG&E), and Federal Executive Agencies (FEA). While ORA and TURN filed protests to the application, PG&E and FEA did not, nor have PG&E and FEA filed any comments on the Settlement.

We conclude that the Settlement, while not signed by all parties, commands the unanimous sponsorship of all active parties in the proceeding. The first part of the test is, therefore, satisfied.

The active parties are Applicants, ORA, and TURN. Applicants represent themselves. ORA represents all ratepayers and TURN represents residential and small commercial ratepayers. We conclude that all affected interests in this proceeding are well represented. The second part of the test is, therefore, satisfied.

Proponents represent that the Settlement complies with all statutes and prior Commission decisions. We agree. The third part of the test is, therefore, satisfied.

Applicants, in their application, made a prima facie case for their original proposal. Proponents have explained how more recent information would have reduced Applicants' original request. Finally, Proponents have explained that the Settlement is a compromise, by the settling parties, on a mutually agreeable outcome. Proponents also point out that the Settlement avoids the costs of litigation and frees the parties' and the Commission's resources for other proceedings.

The application, Settlement, and the testimony supporting the Settlement provide us with sufficient information to evaluate the reasonableness of the Settlement. They also provide us with sufficient information to discharge our future regulatory obligations to the parties and their interests. The fourth part of the test is, therefore, satisfied.

The terms of the Settlement are fully supported by Proponents. Proponents represent all interests and have more than sufficient knowledge and expertise to recommend a reasonable outcome to this proceeding. No party has opposed the Settlement. We have no reason to believe that the negotiations were done in an inappropriate manner or that the terms of the Settlement are unreasonable or unworkable. We, therefore, conclude that the Settlement is reasonable and in the public interest. We also conclude that the Settlement satisfies Rule 51.1(e). We will adopt the Settlement.

Findings of Fact

1. A.98-12-025 was filed on December 21, 1998.

2. Notice of A.98-12-025 appeared on the Commission's Daily Calendar on January 6, 1999.

3. On February 5, 1999 ORA and TURN filed protests to the application and on February 16, 1999, Applicants filed a response.

4. On March 8, 1999, Proponents filed a joint motion seeking approval of a Settlement.

5. No parties objected to the Settlement.

6. Evidentiary hearings are not necessary.

7. The Settlement commands the unanimous sponsorship of all active parties.

8. Proponents are fairly reflective of all affected interests and have sufficient knowledge and experience to recommend a reasonable outcome to this proceeding.

9. The terms of the Settlement do not contravene statutory provisions or prior Commission decisions.

10. The Settlement conveys sufficient information to permit the Commission to discharge its future regulatory obligations regarding the parties and their interests.

Conclusions of Law

1. The Settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

2. The Settlement should be adopted.

3. This order should be effective immediately in order that the appropriate contribution levels can be implemented as soon as possible.

ORDER

IT IS ORDERED that:

1. The Settlement Agreement (Attachment A) is adopted.

2. The Master Trust Agreements shall be amended as specified in the Settlement Agreement.

3. The Settlement is unopposed; therefore, no hearings are necessary in this matter.

4. This proceeding is closed.

This order is effective today.

Dated June 3, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
LORETTA M. LYNCH
TAL C. FINNEY
Commissioners

Decision 03-10-015 (October 2, 2003)

ALJ/JPO/jva

Mailed 10/9/2003

Decision 03-10-015 October 2, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Southern California Edison Company and San Diego Gas and Electric Company for the 2002 Nuclear Decommissioning Cost Triennial Proceeding to Set Contribution Levels for the Companies' Nuclear Decommissioning Trust Funds and Address Other Related Decommissioning Issues.	Application 02-03-039 (Filed March 21, 2002, amended June 17, 2002)

Carol Schmid-Frazee, Attorney at Law, for Southern California Edison Company, and Steven C. Nelson, Attorney at Law, for San Diego Gas and Electric Company, applicants.
Gregory Heiden, Attorney at Law, for the Office of Ratepayer Advocates, James Adams, for the Surfrider Foundation, Bob Finkelstein, Attorney at Law, and Bill Marcus for The Utility Reform Network, interested parties.

TABLE OF CONTENTS

OPINION

I. Summary

The purpose of this nuclear decommissioning cost triennial proceeding (NDCTP) is to set the annual revenue requirements for the decommissioning trusts for nuclear power plants owned by Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) (collectively, the utilities).

SCE requests continuation of its current annual revenue requirement of $25.0 million for San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2&3), and Palo Verde Nuclear Generating Station Units 1, 2, and 3 (Palo Verde).

SDG&E requests an annual revenue requirement of $11.534 million for SONGS 2&3.

By this decision, we set the annual revenue requirement for SCE at $32.848 million for 2003. This results in a $7.848 million increase from its currently authorized revenue requirement. For SDG&E we set the annual revenue requirement at $6.692 million for 2003. This results in a $1.692 million increase over its currently authorized annual revenue requirement. The reasons for the differences between the requested and adopted numbers are different adopted rates of return for the trusts, cost escalation rates, contingency factors, and low level radioactive waste (LLRW) burial costs.

In addition to the above revenue requirements, we find the San Onofre Nuclear Generating Station Unit 1 (SONGS 1) decommissioning work completed as of December 31, 2001 ($91 million) reasonable, find the utilities' estimate of SONGS 1 remaining decommissioning work ($531 million) reasonable, and authorize the utilities to use the tax benefits retained in the non-qualified trust fund for SONGS 1 to fund decommissioning work on that plant.[1]

II. Background

SCE owns 80% of SONGS 1, and 75.05% of SONGS 2&3. SDG&E owns 20% of SONGS 1, 2 & 3.[2] SCE is a non-operating owner of 15.8% of Palo Verde. Arizona Public Service Company (APS) owns 29.10% of Palo Verde, and is the operating agent.[3]

Application (A.) 02-03-020 is the application of Pacific Gas and Electric Company (PG&E) for its 2002 NDCTP. Combined hearings were held for both the instant application and A.03-03-020, although the proceedings were not consolidated. The purpose of the combined hearings was to address issues

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[1] The utilities estimate that the SONGS 1 trusts will be sufficient to meet estimated future decommissioning costs if the tax benefits are retained in the non-qualified trusts. There are two types of trusts. Qualified trusts hold decommissioning funds that result from contributions that qualify for an income tax deduction under U.S. Internal Revenue Code Section 468A. Nonqualified trusts hold decommissioning funds that result from other contributions.

[2] The cities of Anaheim and Riverside own the remaining 3.16% and 1.79% interests in SONGS 2&3, respectively.

[3] The remaining non-operating owners are: Salt River Project (17.49%), El Paso Electric Company (15.80%), Public Service Company of New Mexico (10.20%), The Southern California Public Power Authority (5.91%), and Los Angeles Department of Water and Power (5.70%).

common to both proceedings in a single set of hearings. In that way, a record was developed that allows the Commission to treat common issues consistently. Therefore, the testimony and exhibits of PG&E, SCE, SDG&E, and the Commission's Office of Ratepayer Advocates (ORA) regarding common issues are included in the record for both applications. The testimony and exhibits regarding utility specific issues are included only in the application to which they pertain.

PG&E is not a party to this application. However, it participated in the development of the record. The Surfrider Foundation, and The Utility Reform Network are parties to this proceeding. However, they did not provide testimony or exhibits, cross-examine witnesses, or file briefs. Therefore, the term "parties," as used in this decision, refers to the active parties, SCE, SDG&E and ORA. In addition, the term "participants" refers to PG&E, SCE, SDG&E, and ORA.

Trust fund contribution levels and the resulting revenue requirements are calculated using complex computer models. The models are first used to estimate the decommissioning costs in current dollars. The decommissioning costs are then escalated to the future years in which they will occur. The models then use the current trust fund balances, and estimated future earnings, to estimate the trust fund contributions necessary to pay the decommissioning costs when they occur. The models then determine the revenue requirement needed to provide the contributions. The disputed issues in this proceeding concern model inputs and assumptions as addressed below.

III. Overview

A. SCE

SCE recommends continuation of the current $25 million annual revenue requirement in order to ensure that decommissioning funds are available when needed, maintain rate stability; and ensure that customers receiving the benefits of SONGS 2&3 and Palo Verde operation are equitably burdened with the costs to decommission those facilities. As to SONGS 1, SCE believes no further contributions to the trust funds are needed.

B. SDG&E

SDG&E requests an $11.534 million annual revenue requirement for 2003.[4] As to SONGS 1, SDG&E also believes no further contributions to the trust funds are needed.

IV. Utility-Specific Issues

A. SDG&E 2&3 Decommissioning Cost Estimate

The utilities estimate decommissioning costs for SONGS 2&3 at $2.23 billion. ORA proposes a reduction of $15 million in reactor vessel and internals segmentation and removal costs, and a reduction of $77 million related to spent fuel wet storage costs. ORA also opposes the utilities' escalation rates

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[4] In its original testimony filed jointly with SCE on March 21, 2002, SDG&E proposed to bifurcate the issue of future contribution levels for SDG&E's customers from this proceeding, and move it to its 2004 cost of service proceeding. SDG&E's initial proposal, had it been adopted, necessarily would have involved litigating issues, such as rates of return, in SDG&E's 2004 cost of service proceeding. SDG&E amended the application on June 17, 2002 to address the issue of future contribution levels in this proceeding, rather than in its 2004 cost of service proceeding.

and rates of return. These issues are addressed later in this decision under common issues.

The utilities' estimate of the decommissioning costs for SONGS 2&3 is based on a site-specific review of the decommissioning requirements for SONGS 2&3, and takes into account experience in decommissioning SONGS 1.

The utilities' SONGS 2&3 decommissioning cost estimate includes increased costs associated with a four-year schedule increase. The schedule increase resulted in additional fixed project costs of $96 million. These fixed project costs are associated with the base project staff.

ORA recommends that the Commission reject the utilities' $150 million reactor vessel internals segmentation, reactor vessel segmentation, and large component removal activities estimate for SONGS 2&3, and instead use a $135 million estimate. ORA contends that the very high costs for these activities for SONGS 1 were partially caused by the newness of the segmentation and removal processes. ORA also argues that there will be technological developments that will simplify these processes. Therefore, ORA recommends a 10% ($15 million) reduction from the utilities' estimate to account for future improvements in decommissioning methods.

Regarding spent fuel wet storage and additional LLRW volume disposal costs, the utilities' estimate includes $96 million for fixed project costs for a four-year schedule extension. ORA contends that the fixed costs that the utilities propose are 102% of direct costs for LLRW, in contrast to the 35% fixed cost share the utilities used for their overall project estimate. ORA maintains that the four-year schedule extension does not mean that the scope of general decommissioning work should expand proportionately by four more years at an additional cost of $96 million. ORA contends that the decommissioning work should be spread out according to the new 15-year schedule, and the staffing costs should also be spread out over that period. ORA recognizes that there are still fixed costs that need to be added for four years of additional wet fuel storage, including the corporate overhead and base project staff. Therefore, ORA proposes reducing the utilities' $96 million estimate, by $77 million, to $19 million. The $19 million includes 20% for overhead, plus needed staff.

<u>Discussion</u>

ORA recommends a 10% reduction in costs for reactor vessel internals segmentation, reactor vessel segmentation, and large component removal activities to account for future improvements in decommissioning methods. While there may be such improvements in the future, what they may be, and the effect on costs is unknown. ORA offers no specific reasons why such improvements, if they occur, will result in a 10% savings. Therefore, we will not adopt ORA's recommendation.

As to the proposed staffing changes, ORA proposes reducing the fixed cost estimate because it believes that the schedule increase results in doing the same amount of work over a longer period of time. However, that is not the case. The additional costs are for additional work that will be performed. Therefore, we will not adopt its recommendation.

B. Palo Verde Decommissioning Costs

SCE estimates its share of decommissioning costs for Palo Verde at $503 million. ORA proposes a $27 million reduction in staffing costs associated with schedule changes, and a $3.5 million reduction in large scale component removal costs. ORA also opposes SCE's contingency factor, escalation rates, and rates of return. These issues are addressed later in this decision under common issues.

SCE's estimate is based on a study performed for APS by TLG Services, Inc. (TLG). When assumptions in the TLG study were inconsistent with SCE's understanding of industry decommissioning experience, or its experience decommissioning SONGS 1, SCE applied adjustments. SCE says its decommissioning cost estimate for Palo Verde is not as detailed or definitive as the updated SONGS 2&3 cost estimate.

Changes to site staffing expenses account for $27 million of the increased staffing costs for dismantling activities. The increase is for engineering, cost and scheduling, emergency preparedness, and security work functions as well as support functions such as health and safety, legal, and regulatory affairs. SCE believes these staffing increases are consistent with increases currently planned for other decommissioning projects in the United States reviewed by TLG.

The SONGS 2&3 and Palo Verde reactor vessels, reactor vessel internals, and large components are of similar design and size. Therefore, SCE used the same estimation methods for internals segmentation, vessel segmentation, and large component removal activities at both SONGS 2&3 and Palo Verde.

ORA recommends the Commission disallow $27 million in increased labor costs included in SCE's estimate because SCE provided no specific justification, such as the previously unanticipated tasks these additional personnel will perform. As with the SONGS 2&3 estimates, ORA recommends that SCE's estimates for internals segmentation, vessel segmentation, and large component removal activities for Palo Verde be reduced by 10% ($3.55 million) to account for future improvements in decommissioning methods.

Discussion

SCE's estimate of increased staffing levels is based on the staffing levels associated with other decommissioning projects in the United States. No decommissioning plan has yet been developed for Palo Verde. Therefore, we would not expect the level of detail that ORA would have us require at this time. As a result, we will not adopt ORA's recommendation.

ORA recommends a 10% ($3.55 million) reduction in costs for internals segmentation, vessel segmentation, and large component removal activities to account for future improvements in decommissioning methods. While there may be such improvements in the future, what they will be, and the effect on costs is unknown. ORA offers no specific reasons why such improvements will result in a 10% savings. Therefore, we will not adopt its recommendation.

V. SONGS 1 Decommissioning

A. $91 Million Incurred Costs for Decommissioning

In D.99-06-007, the Commission approved a settlement establishing a presumption that the utilities' conduct is reasonable in performing SONGS 1 decommissioning work if the scope of the work completed, and costs incurred, are bounded by the most recently approved SONGS 1 decommissioning cost estimate. This presumption means that any entity claiming the utilities acted unreasonably would bear the burden of proving their claim.

The utilities say the $91 million of SONGS 1 decommissioning work completed as of December 31, 2001, is reasonable because it is less than the estimated $96 million cost for the work that was approved in D.99-06-007. ORA does not oppose the reasonableness of the expenditures. Pursuant to D.99-06-007, we find that the SONGS 1 $91 million decommissioning work completed as of December 31, 2001 is reasonable.

B. SONGS 1 Decommissioning Work Remaining as of December 31, 2001

The utilities represent that the SONGS 1 remaining decommissioning work cost estimate ($531 million) is based on site-specific detailed planning studies. More than 60% of the remaining SONGS 1 decommissioning work scope is subject to fixed price contracts. As a result, the utilities reduced the contingency for remaining SONGS 1 decommissioning work to 15%, in recognition of the reduced cost uncertainty associated with remaining decommissioning work scope. Therefore, the utilities request that the Commission find their estimate for remaining work at SONGS 1 reasonable, and authorize them to access up to 90% of this estimate from the trusts to pay for the work.

ORA does not oppose the utilities' estimate of the work remaining, or their proposal to use trust funds to pay for it.

The utilities developed their estimate through detailed planning studies, executed contracts that have either fixed the cost or minimized the cost uncertainties for approximately 60% of the remaining work, and reduced the contingency factor to 15%. In addition, ORA does not oppose it. Therefore, we will adopt it.

In D.99-06-007, we authorized the utilities to access trust funds to pay for decommissioning work up to 90% of the approved estimate. The utilities' request to do so is unopposed. Since granting the request will avoid finance charges due to delays in trust fund withdrawals to pay for decommissioning work, we see no reason not to grant it.

C. Use of The Tax Benefit Created When Non-Qualified Trust Funds are Expended

There are two types of trusts. Qualified trusts hold decommissioning funds that result from contributions that qualify for an income tax deduction under U.S. Internal Revenue Code Section 468A. Nonqualified trusts hold decommissioning funds that result from other contributions. The utilities request authority to use tax benefits retained in the SONGS 1 non-qualified trust fund to continue decommissioning work, if necessary.

The utilities forecast that the $482 million (2001 dollars) available in the SCE SONGS 1 decommissioning trust and the $166 million (2001 dollars) available in the SDG&E SONGS 1 decommissioning trust will be sufficient to meet the estimated future cost requirement. However, the available funds include non-qualified trust fund tax benefit values of $132 million (SCE) and $42 million (SDG&E) as of December 31, 2001. Pursuant to the settlement approved in D.99-06-007, the utilities retained the tax benefits associated with deducting decommissioning costs that were reimbursed from the non-qualified decommissioning trust, rather than immediately returning these tax benefits to ratepayers when these decommissioning costs were incurred. The utilities believe they may need to utilize these tax benefits in order to assure sufficient funding for the remaining SONGS 1 decommissioning work. Therefore, they request authorization to use these tax benefits to pay for the remaining decommissioning work, and avoid any need to seek further ratepayer funding. ORA does not oppose the request.

By granting the request, we ensure that there will be sufficient funds to pay for decommissioning without imposing an additional revenue requirement on ratepayers to pay for decommissioning. If we were to require the tax benefits to be immediately returned to ratepayers, we would have to impose a revenue requirement on them to provide additional funds to the trusts to pay for decommissioning. There would also be additional costs to implement the return of the benefits to the ratepayers. In addition, since SONGS 1 is not operational, imposing a revenue requirement on future ratepayers would violate one of the purposes of the trusts, which is to have the ratepayers who receive power from the plant pay for its decommissioning. Therefore, we see no reason to discontinue the practice we previously adopted.

VI. Common Issues

A. Rate of Return

For estimating the earnings of the nuclear decommissioning trusts, SCE estimates a pre-tax return on equities that is in the range of 7.42% to 10.11%, and a pre-tax return on fixed income assets that is in the range of 4.21% to 6.03%. SDG&E estimates a pre-tax return on equities of 7.42%, and a pre-tax return on fixed income assets of 6.03%. PG&E estimates an 11.0% pre-tax return on equities, and a 7.0% pre-tax return on its fixed income assets. ORA recommends a 12.5 % pre-tax return on equities, and a 7.4 % pre-tax return on fixed income assets.

SCE used two sets of return assumptions to establish a range of contributions to its decommissioning trust funds for SONGS 2&3 and Palo Verde. The first set of assumptions relies on DRI-WEFA (DRI)[5] projections for: (1) the Standard & Poor's (S&P) 500 Stock Price Index, and (2) the dividend yield for the S&P 500 Stock Index to calculate a projection of future equity returns. SCE maintains that when compared to estimates derived from historical data, DRI's Treasury bond yield projections are too high relative to their inflation projection, and DRI's estimate of future equity returns is too low. Therefore, it constructed an alternative set of return assumptions that adjust Treasury bond yield projections and future equity returns to reflect historical relationships. SCE argues that its two sets of return assumptions bound expected returns for the decommissioning trust funds.

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[5] DRI is a company that provides economic forecasts.

SDG&E says that it does not make sense to adopt identical rate of return assumptions for itself, SCE and PG&E because each company has its own separate and independent decommissioning trusts with portfolios of hundreds of different domestic and international stocks. Moreover, each company has different investment committees with different risk tolerances. As a result of these differences, the utilities may choose different portfolio asset allocations, investment strategies, and investment advisors, all of which will impact the realized investment rates of return.

SDG&E used DRI projections as the basis for computing expected equity and fixed-income asset returns in this filing. It maintains that DRI forecasts should be consistently used in determining SDG&E's funding requirements during this proceeding and others. SDG&E also argues that using DRI forecasts consistently over time provides the Commission with a consistent gauge to assess performance, and provides fewer opportunities for gaming that could occur if methodologies are changed every three years. Specifically, DRI projects that the average annual pre-tax return for the S&P 500 and 10-year Treasury bond will average 7.42% and 6.03% respectively from 2002 through 2026, which covers the period that contributions will be made to the decommissioning trusts.[6] SDG&E says the DRI forecast is also consistent with equity projections from a variety of investment professionals.

PG&E's equity return forecast is based on the annualized rate of return for the U.S. equity market for rolling ten-year periods covering 80 years, from

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[6] SDG&E expects to collect decommissioning contributions only through 2013 (through the end of operations), although it will continue to invest in equities for another 5 or 10-year period until commencement of decommissioning.

1920 through 2001. The forecasted return on fixed income assets is also based on long-term rates of return. PG&E believes that forecasts of long-term market returns are traditionally based on historic market experience over very long time periods, and it is preferable to include more data points where available to decrease the variance in the results. In PG&E's last general rate case (D.00-02-046), the Commission adopted an 11.0% pre-tax return on equities. PG&E believes an 11.0% pre-tax return on equities remains a reasonable and conservative forecast. In D.00-02-046, the Commission also adopted a 7.0% pre-tax return on the fixed income portion of PG&E's trusts. PG&E recommends the same value in this proceeding.

ORA recommends a 12.5% pre-tax return on equities, and a 7.4% pre-tax return for fixed income investments. ORA's 12.5% pre-tax return on equities is derived from the 48-year (1954-2001) average annual return for the S&P 500 of 12.77%. ORA believes that evaluating historic performance beginning in 1954, after the Federal Reserve removed its cap on government debt rates, creates a more reliable historic record than using data beginning before the Great Depression as PG&E has done. Furthermore, using 1954 as a starting date allows analysis of 10-year Treasury bond data.

ORA contends that the Commission should not adopt PG&E's rate of return assumptions because the historic results have been much higher. ORA points out that PG&E's estimates are lower than readily available investment options such as tax-free municipal bonds. ORA believes its 7.4% pre-tax return for fixed income investments is comparable to the DRI forecast, current municipal bond rates, and actual performance of the trust funds.

While ORA does not oppose SCE's methods, it does oppose SDG&E's methods. SDG&E relied exclusively on DRI long-term forecasts. In contrast, SCE's rate of return estimate uses both DRI and its own estimates to forecast its decommissioning fund performance. ORA says SCE's approach is preferable because it incorporates consideration of the historical premium for equity risk that it believes has virtually disappeared in the DRI projections.

ORA says that SDG&E did not back-test the DRI projections for accuracy, and that DRI's short-term equity performance forecast from the 1998 NDCTP did not forecast the current state of the equities market. ORA believes that using the DRI projections alone, without any adjustments for historical risk premium, is not a valid methodology.

<u>Discussion</u>

As pointed out by SDG&E, each utility has its own separate and independent decommissioning trust portfolios. In addition, each utility has different investment committees with different risk tolerances. As a result of these differences, SCE, SDG&E, and PG&E's realized investment rates of return will be different. However, in this proceeding, none of the participants has indicated specifically how these factors are incorporated into its estimates. In addition, the three utilities' trusts will have access to the same markets. As a result, their trusts will have the same investment opportunities. Therefore, we will adopt a uniform set of rate of return projections for all three utilities.

For equity returns, there is merit in using long-term historical data as used by PG&E and ORA. However, their presentations demonstrate that selection of which data to use can give quite different results. In contrast to the historical data, the DRI forecasts, which SDG&E and SCE use in different ways, yield much lower returns. No participant has demonstrated that its estimate is substantially better than the rest. The midpoint of the range of values recommended by the participants is below the 11.0% pre tax return on equities we adopted for PG&E in D.00-02-046.[7] This leads us to believe that some reduction is appropriate. Therefore, we will adopt a 10.5% pre-tax return on equities, which is slightly above the midpoint of the range of values estimated by the participants.

Regarding fixed assets, no participant has demonstrated that its estimate is substantially better than the rest. Since the midpoint of the range of values recommended by the participants is below the 7.0% pre tax return on fixed assets we adopted for PG&E in D.00-02-046, some reduction is appropriate. Therefore, we will adopt a 6.0% pre-tax return on fixed assets, which is slightly above the midpoint of the range of values estimated by the participants.

B. Escalation Rate

The escalation rate is used to bring the current estimate of decommissioning costs to the future years in which the costs will be incurred.

The utilities calculated separate escalation rates for: (1) labor, (2) the combined category of material, equipment, and other, and (3) low level radioactive waste (LLRW) burial costs. They based the separate escalation rates for labor, and the combined category of material, equipment, and other upon DRI projections. The escalation rate for the combined category of material, equipment, and other was based on a weighted average of the escalation rates for each component.

The utilities used Nuclear Regulatory Commission (NRC) published data to estimate an escalation rate for LLRW burial costs. The NRC data shows

[7] The current trust fund contribution levels for SCE and SDG&E were adopted in D.99-06-007. That decision approved a settlement and, therefore, is not a precedent.

rapidly increasing burial costs followed by large, discrete jumps. The utilities utilized two similar statistical models to produce ten estimates ranging from 6.8% to 19.9%. They then chose a 10% LLRW burial cost escalation rate because of the possibility of additional large jumps in LLRW burial costs.

The utilities did not include a separate contingency factor in their calculation of escalation rates.

PG&E calculated the simple average of the escalation rates for labor, LLRW disposal costs, contract labor, materials, and other costs to arrive at an annual escalation rate. It then added a 20% contingency factor to arrive at its recommended overall escalation rate.

PG&E's escalation rates, except for LLRW burial costs, are based on DRI forcasts. The DRI forcasts do not extend beyond 2023. Therefore, PG&E used a DRI forecast to calculate escalation rates until 2023, and used the 2023 rate for subsequent years. It represents that its labor, materials, contract labor and other escalation rates are comparable to the most recent DRI forecasts.

PG&E believes that using a weighted average simply adds false precision to a highly speculative estimate. PG&E says that its methodology is the same as was used to calculate the overall escalation rate used by PG&E, and adopted by the Commission in D.00-02-046.

PG&E added a 20% contingency factor to come up with its overall escalation rate.[8] PG&E states that the contingency factor ensures against future ratepayer liabilities by recognizing uncertainties with regard to changes in the

[8] In D.00-02-046, the Commission adopted a 25% contingency factor.

economy, and protects against uncertainties in how much decommissioning costs may increase in the future.

PG&E recommends a 7.5% escalation rate for LLRW burial costs for use in this proceeding as it was in D.00-02-046. PG&E says it is uncertain where the LLRW will be buried, and how much it is going to cost. PG&E believes that since the uncertainty is even greater now, with the Ward Valley disposal site stalled, and other sites about to stop taking California LLRW, a 7.5% escalation rate is a conservative and reasonable assumption.

ORA argues that an unweighted average escalation rate makes no statistical sense, and overestimates actual escalation. ORA maintains that PG&E's unweighted calculation gives a 20% weighting to each of the five categories. However, the equipment and materials category accounts for 29%, and the "other" category accounts for 6% of actual expenditures, rather than the 20% used by PG&E for these two categories. ORA contends that this proves the inaccuracy of using an unweighted average. As a result, ORA recommends that a weighted average, based on expenditures, be used.

ORA also says that PG&E's use of the 2023 value for years after 2023, when using DRI forecasts in calculating an average escalation rate, gives undue weight to the 2023 value. It points out that, while the escalation rates in the earlier years have some relation to historic costs, the years after 2023 are not based on any independent forecast.

ORA contends that PG&E relied on a DRI forecast from 2001 in generating the labor escalation rate, and that a more recent DRI forecast yields significantly lower numbers. Therefore, ORA recommends that the Commission adopt the most recent DRI data.

ORA also says that PG&E's request for an additional 20% contingency factor is redundant since an overall contingency factor is already built into its decommissioning cost estimate.

ORA recommends a 5% escalation rate for LLRW burial costs. This is because LLRW burial costs increased only 2.4% from 1996 to the present, and only 4.3% from 2000 to 2001. ORA says that PG&E's only rationale for using a 7.5% LLRW burial cost escalation rate is that the Commission has previously adopted it.

ORA also opposes the utilities' proposed 10% LLRW burial cost escalation rate. It says the utilities relied entirely on NRC disposal cost indexes from 1986 to 2000, but did not attempt to independently verify the data. It believes that a reasonable cost escalation projection should consider additional factors to help explain a data set, and should look beyond the numbers to determine causes for their variation, as well as possible future developments. ORA says the utilities performed no such evaluation, and did not inquire as to why certain years were missing from the NRC data, or why the costs jumped significantly in certain years.

ORA maintains that the utilities' choice of data is not representative of future costs. ORA says the data used by the utilities, from three disposal sites for the period 1986-2000, reflects non-competitive disposal pricing. It also says that more recent data under more competitive conditions for Barnwell in South Carolina, and Envirocare in Utah, including contracted SONGS 1 LLRW burial costs, were not considered in the utilities' estimate. ORA believes the utilities have projected the most expensive possible future scenario without consideration of the prospect of a more competitive market for burial of LLRW.

Discussion

While we agree with PG&E that we are dealing with a highly speculative estimate, that is no reason to deliberately introduce an error into the calculation. ORA has demonstrated that the actual expenditures do not support the equal weighting that results from a simple average. In addition, the utilities used a weighted average. Therefore, except for LLRW burial costs, we will require the use of a weighted average.

The participants agree that a DRI forecast should be used to forecast escalation rates, except for LLRW burial costs. The disagreement appears to be over which forecast to use. Here again, although forecasts of the future are speculative by nature, it makes sense to use the most recent available forecasts. Therefore, we will use the DRI forecasts used by ORA, which are the most recent DRI forecasts in the record.

We note that the DRI forecasts run only through 2023. When determining an average escalation rate for a forecast period, PG&E uses the 2023 rate for subsequent unforecasted years. However, as pointed out by ORA, this approach gives additional weight to the last forecasted year. There is no reason that the forecast for 2023 is any better than the forecast for other years. Therefore, the average rate for the forecast period shall be used for the subsequent unforecasted years. This means that the rate for 2024, and each year thereafter, would be the average of the rates for 2002-2023.

We adopt contingency factors for cost estimates when the work to be done may change substantially over time due to such things as changing NRC requirements. This is the case with the decommissioning cost estimate. However, the escalation rate is an estimate of the rate of change in the cost of specified work. The Commission routinely adopts forecasts of cost increases, in general rate cases for example, without applying contingency factors. Since the risk of substantial changes in the work to be done and the requirements that must be met to do the work is covered by the contingency factor applied to the decommissioning cost estimate, there is no reason to apply a separate contingency factor to the calculation of the escalation rate. We also note that the utilities are not requesting one. Therefore, we will not adopt a separate contingency factor for escalation rates.

Regarding the LLRW burial cost escalation rate, the utilities estimate a 10% rate based on economic modeling of NRC data, PG&E proposes a 7.5% escalation rate based on our previous adoption of it, and ORA proposes a 5% escalation rate based on burial cost increases from 1996 to the present. Since the NRC data shows significant jumps and has no data for some years, we believe that it demonstrates the uncertainty of the costs, but does not provide a good basis for estimation. Therefore, we will not adopt the utilities' 10% escalation rate. Likewise, ORA has not demonstrated that the recorded burial costs increases from 1996 to the present provide a better basis for estimation than the NRC data. Therefore, we will not adopt ORA's 5% escalation rate. As pointed out by PG&E, it is uncertain where the wastes will be buried, and at what cost. Burial costs are no less certain now than they were when the Commission adopted a 7.5% escalation rate for PG&E in D.00-02-046. Therefore, since no participant has demonstrated that its estimate is more accurate than the other estimates, it is reasonable to continue using the previously approved rate. This rate also happens to be the midpoint of the rates recommended by the participants.

C. LLRW Burial Costs

LLRW burial costs are the costs of burying the LLRW generated by the decommissioning of a nuclear power plant. The utilities' LLRW burial cost estimate is $72.60 per cubic foot for SONGS 2&3. This estimate is based on the assumed availability of a licensed disposal facility with rates comparable to the Envirocare facility, and located within 1,500 miles of the SONGS site.

SCE's LLRW burial cost estimate for Palo Verde is $87 per cubic foot. SCE says its estimate is consistent with APS's assumptions about the burial sites that APS will use for Palo Verde LLRW.

PG&E estimates LLRW burial costs of $404 per cubic foot.[9] PG&E points out that, in D.00-02-046, the Commission adopted LLRW burial costs at the Ward Valley site of $509 per cubic foot in 1997 dollars. Because there is no indication that Ward Valley will ever be available during the times it will be needed, PG&E based its estimate on the costs of the only facility in America to which it can send more-contaminated LLRW, at Barnwell, South Carolina. Even though Barnwell is going to stop accepting wastes from non-Atlantic Compact generators such as PG&E, SCE, and SDG&E, PG&E believes Barnwell's costs are appropriate because they include all of the costs a future disposal facility (such as Ward Valley is intended to be) would likely bill a generator. Given the complete uncertainty over where these wastes will eventually go, and how much it will

[9] In PG&E's application and exhibits, it used LLRW burial costs of $404 per cubic foot for Diablo Canyon Power Plant Units 1 and 2 (Diablo Canyon). For its Humboldt Bay Power Plant Unit 3 (Humboldt) 2015 decommissioning, it used $450 per cubic foot. For Humboldt early decommissioning, it used $140 per cubic foot for Class A LLRW and $450 per cubic foot for the more hazardous classes of LLRW. This yields an average cost of $147 per cubic foot for early decommissioning. In its briefs, PG&E presented its recommendation as $404 per cubic foot without distinguishing between Diablo Canyon and Humboldt. Therefore, we address only PG&E's $404 per cubic foot recommendation herein.

cost once that place is identified and operational, PG&E believes its $404 per cubic foot estimate is optimistic.

ORA recommends that the Commission adopt the utilities' LLRW burial cost estimate of $72.60 per cubic foot. ORA claims that PG&E derives its $404 estimate from recent cost increases at Barnwell and other facilities. ORA believes that PG&E's methodology is faulty because it ignores the likely availability of alternative facilities. ORA argues that the utilities' $72.60 per cubic foot estimate reflects their current burial cost for all classes of LLRW. ORA does not oppose the utilities' estimated LLRW burial costs for Palo Verde.

Discussion

In D.00-02-046, we adopted burial costs of $509 per cubic foot (in 1997 dollars). In this proceeding, the participants have recommended costs ranging from $76.20 to $404 per cubic foot. Therefore, it appears that the participants agree that the costs should be lower. However, they disagree on how much lower they should be.

Only PG&E and SCE actually prepared LLRW burial cost estimates. SDG&E and ORA recommend use of SCE's estimate. In addition, we have no reason to believe that there will be sufficient alternative burial sites available to lower costs due to competition, as recommended by ORA. Therefore, we are left with PG&E and SCE's estimates.

Although both PG&E and SCE's estimates are based on actual costs, neither estimate has been demonstrated to be substantially better than the other. This circumstance argues for using a cost of $240 per cubic foot, the midpoint of the range of the proposed values. However, since SCE has done a more comprehensive analysis of decommissioning costs, especially for SONGS 2&3, we will give slightly more weight to its estimates. As a result, we will adopt a

LLRW burial cost of $200 per cubic foot. This amount is a bit more than twice SCE's estimates, slightly less than half of PG&E's $404 estimate, and substantially less than the cost adopted in D.00-02-046.

D. Contingency Factor – SONGS 2&3

The contingency factor is used to increase the estimated decommissioning costs to allow for uncertainties in the required decommissioning work and, therefore, the costs. The utilities retained ABZ Inc. (ABZ) to assist SCE in preparing the site-specific decommissioning cost study for SONGS 2&3. SCE provided ABZ with information about decommissioning costs, based on its experience decommissioning SONGS 1, for use in estimating the decommissioning costs. In addition, SCE was able to estimate for ABZ many SONGS 2&3 decommissioning costs that were previously undefined, and assumed to be included within the 40% contingency included in the previous estimate. As a result, SCE reduced the contingency factor for SONGS 2&3 from 40% to 21%.

ORA does not oppose the use of a 21% contingency factor for SONGS 2&3. ORA agrees that the 21% contingency factor is appropriate because the utilities were able to apply their experience decommissioning SONGS 1 to their SONGS 2&3 estimate, thereby reducing the uncertainty.

We concur, SCE has utilized its decommissioning experience with SONGS 1 to refine its estimate for SONGS 2&3. These refinements lead to a substantial reduction in the contingency factor. As a result, we will adopt the utilities' proposed contingency factor for SONGS 2&3.

E. Contingency Factor - Palo Verde

APS retained TLG to prepare a site-specific decommissioning cost study for Palo Verde. SCE used TLG's study as a resource to develop its estimate. SCE made adjustments to correct large discrepancies that it believes a 40% contingency factor will not cover. However, SCE believes the adjustments did not refine the Palo Verde estimate sufficiently to reduce the contingency factor. SCE notes that Palo Verde has not entered into a detailed planning phase for imminent shutdown and decommissioning. Therefore, working level studies that would occur in a detailed planning phase for imminent shutdown and decommissioning, thereby decreasing the level of uncertainty for estimated decommissioning costs, have not yet been performed. As a result, SCE proposes a 40% contingency factor.

ORA recommends a 30% contingency factor for Palo Verde. ORA believes that SCE's experiences with SONGS 1 decommissioning, as well as its review of decommissioning at other facilities, should allow it to reduce the contingency factor for Palo Verde. ORA argues that, since SCE has used its experience and knowledge of decommissioning to increase its cost estimates for Palo Verde by approximately $101 million, it should use that same experience and knowledge to reduce its contingency factor for Palo Verde.

ORA realizes that the planning for Palo Verde decommissioning is at an earlier stage than the planning for SONGS 2&3. Therefore, ORA recommends a 30% contingency factor, the midpoint between the 21% SCE proposes for SONGS 2&3, and the 40% SCE proposes for Palo Verde. Additionally, ORA believes that since SCE has updated its cost estimate by 25% because of reduced cost uncertainty, a 25% reduction in the contingency factor, from 40% to 30%, is appropriate.

<u>Discussion</u>

SCE has utilized its decommissioning experience and knowledge to refine its estimate for Palo Verde as it has for SONGS 2&3. These refinements should lead to some reduction in uncertainty, and therefore, some reduction in the contingency factor. However, we are not convinced that there is necessarily a direct relationship between an increase in the decommissioning cost estimate, and a reduction in the contingency factor, as proposed by ORA. We note that SONGS 2&3 are estimated to begin decommissioning in 2022. The Palo Verde units are estimated to begin decommissioning in 2024-2027, only a few years later. This too suggests a lower contingency factor. However, we are also aware that Palo Verde is operated by APS rather than SCE, and that no detailed planning, similar to that which has been done for SONGS 2&3, has been done for decommissioning Palo Verde. Therefore, the 21% contingency factor adopted for SONGS 2&3 would be inappropriate for Palo Verde.

Neither party has demonstrated that its recommendation is substantially better than the other's recommendation. At the same time, their arguments convince us that a reasonable contingency factor lies between 30% and 40%. Since there is no reason to give more weight to either parties' estimate, we will adopt a 35% contingency factor.

VII. Conclusion

As discussed above, we have adopted the following modifications to SCE and SDG&E's calculations of the decommissioning cost revenue requirements:

- A 10.5% pre-tax return on equities.
- A 6.0% pre-tax return on fixed assets.
- Escalation rates, except for LLRW burial costs, based on the most recent DRI forecasts in the record, using weighted averages, and no separate contingency factor.
- A 7.5% escalation rate for LLRW burial costs.
- LLRW burial costs of $200 per cubic foot.

- A contingency factor of 35% for Palo Verde.

Based on the above modifications to the decommissioning cost calculations, we adopt an annual revenue requirement for SONGS 2&3 for SCE of $21.160 million, respectively. We also adopt an annual revenue requirement for Palo Verde $11.688 million. This results in an overall annual revenue requirement for SCE of $32.848 million.

Based on the above modifications to the decommissioning cost calculations, we adopt an annual revenue requirement for SONGS 2&3 for SDG&E of $6.692 million.

In addition to the above revenue requirements, we find the SONGS 1 decommissioning work completed as of December 31, 2001 ($91 million) reasonable, find the utilities' estimate of SONGS 1 remaining decommissioning work ($531 million) reasonable, and authorize the utilities to use the tax benefits retained in the non-qualified trust fund for SONGS 1 to fund decommissioning work on that plant.

This decision should be effective immediately, so that the revenue requirements adopted herein can be put into effect as soon as possible.

VIII. Rate Proposal

SCE does not propose a rate change in this proceeding. SDG&E requests a rate increase, and proposes to implement it on an equal cents per kilowatt-hour basis, consistent with D.00-06-034. D.00-06-034 requires that decommissioning costs be allocated on an equal cents per kilowatt-hour basis. Therefore, we will require the utilities to implement the revenue requirements adopted herein on an equal cents per kilowatt-hour basis.

IX. Procedural Matters

In Resolution ALJ 176-3085, dated April 4, 2002, the Commission preliminarily categorized this application as ratesetting, and preliminarily determined that hearings were necessary. Hearings were held on September 16 and 17, 2002.

X. Comments on the Proposed Decision

The proposed decision of ALJ O'Donnell was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed by SCE, SDG&E and ORA. All comments were considered. SCE raises one matter that should be addressed.

SCE and SDG&E will need to request a revised Schedule of Ruling Amounts from the federal Internal Revenue Service (IRS) in order to implement this decision. To facilitate obtaining a favorable ruling from the IRS, SCE, and SDG&E ask that tables showing the revenue requirement, assumptions, and fund disbursements adopted herein be included in this decision. The request is reasonable, and we will grant it. The tables for SCE and SDG&E are included as Attachments A and B, respetively.

XI. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner, and Administrative Law Judge (ALJ) Jeffrey P. O'Donnell is the principal hearing officer in this proceeding.

Findings of Fact

1. SCE owns 80% SONGS 1, and 75.05% of SONGS 2&3.
2. SDG&E owns 20% of SONGS 1, 2 & 3.
3. SCE is a non-operating owner of 15.8% of Palo Verde.

4. APS owns 29.10% of Palo Verde, and is the operating agent.

5. The utilities' estimate for the decommissioning costs of SONGS 2&3 is based on a site-specific review of the decommissioning requirements for SONGS 2&3, and takes into account experience in decommissioning SONGS 1.

6. While there may be improvements in internals segmentation, vessel segmentation, and large component removal activities in the future, what they may be, and the effect on costs is unknown.

7. ORA offers no specific reasons why improvements in internals segmentation, vessel segmentation, and large component removal activities, if they occur, will result in a 10% savings at SONGS 2&3.

8. The utilities' proposed staffing changes for spent fuel wet storage and additional LLRW volume disposal costs are for additional work that will be performed.

9. SCE's decommissioning cost estimate for Palo Verde is not as detailed or definitive as the updated SONGS 2&3 cost estimate.

10. The SONGS 2&3 and Palo Verde reactor vessels, reactor vessel internals, and large components are of similar design and size.

11. No decommissioning plan has yet been developed for Palo Verde.

12. ORA offers no specific reasons why improvements in decommissioning methods for internals segmentation, vessel segmentation, and large component removal activities will result in a 10% savings in the future at Palo Verde.

13. In D.99-06-007, the Commission approved a settlement establishing a presumption that the utilities' conduct is reasonable in performing SONGS 1 decommissioning work if the scope of the work completed and costs incurred are bounded by the most recently approved SONGS 1 decommissioning cost estimate.

14. SCE completed the SONGS 1 decommissioning work, as of December 31, 2001, for $91 million, which is less than the $96 million estimate approved in D.99-06-007.

15. No party contested the reasonableness of the $91 million in expenditures.

16. The utilities' $531 million estimate of SONGS 1 remaining decommissioning work, based on site-specific detailed planning studies, is unopposed.

17. The utilities' request to access up to 90% of the $531 million estimate from the trusts to pay for the decommissioning work is unopposed.

18. In D.99-06-007, the Commission authorized the utilities to access trust funds to pay for decommissioning work up to 90% of the approved estimate.

19. Granting the utilities' request to access up to 90% of the approved estimate from the trusts to pay for the decommissioning work will avoid finance charges due to delays in trust fund withdrawals to pay for decommissioning work.

20. More than 60% of the remaining SONGS 1 decommissioning work scope is subject to fixed price contracts.

21. The utilities reduced the contingency factor for remaining SONGS 1 decommissioning work to 15%.

22. The utilities have $482 million available in the SCE SONGS 1 decommissioning trust, and $166 million available in the SDG&E SONGS 1 decommissioning trust.

23. The SONGS 1 trust funds include non-qualified trust fund tax benefit values of $132 million (SCE) and $42 million (SDG&E) as of December 31, 2001.

24. Pursuant to the settlement approved in D.99-06-007, the utilities retained the tax benefits associated with deducting decommissioning costs that were

reimbursed from the SONGS 1 non-qualified decommissioning trust, rather than immediately returning these tax benefits to ratepayers.

25. The utilities' request to use tax benefits retained in the non-qualified trust fund to continue SONGS 1 decommissioning work is unopposed.

26. If the Commission were to require the tax benefits to be immediately returned to ratepayers, it would have to impose a revenue requirement on them to provide additional funds to the trusts to pay for decommissioning.

27. There would also be additional costs to implement the return of the tax benefits to the ratepayers.

28. Since SONGS 1 is not operational, imposing a revenue requirement on future ratepayers would violate one of the purposes of the trusts, which is to have the ratepayers who receive power from the plant pay for its decommissioning.

29. In D.00-02-046, the Commission adopted an 11% pre-tax return on equities, and a 7% pre-tax return on the fixed income portion of PG&E's trusts.

30. No participant has indicated specifically how differences in decommissioning trust portfolios, and investment committee risk tolerances are incorporated into its rate of return estimates.

31. The three utilities' trusts will have access to the same securities markets, with the same investment opportunities.

32. While there is merit in using long term historical data for estimating rates of return, selection of which data to use can give quite different results.

33. The DRI forcasts, which SDG&E and SCE use in different ways, yield much lower returns than the historical data used by PG&E and ORA.

34. No participant has demonstrated that its estimate of pre-tax returns on equities is better than the other participant's estimates.

35. Since the midpoint of the pre-tax returns on equities recommended by the participants is lower than the 11% pre-tax return on equities adopted in D.00-02-046, a reduction in the pre-tax return on equities is appropriate.

36. A 10.5% pre-tax return on equities is slightly above the midpoint of the range of values estimated by the participants.

37. The current trust fund contribution levels for SCE and SDG&E were adopted in D.99-06-007.

38. No participant has demonstrated that its estimate of pre-tax returns on fixed assets is better than the other participant's estimates.

39. Since the midpoint of the pre-tax returns on fixed assets recommended by the participants is lower than the 7% pre-tax return on fixed assets adopted in D.00-02-046, a reduction in the pre-tax return on fixed assets is appropriate.

40. A 6.0% pre-tax return on fixed assets is slightly above the midpoint of the range of values estimated by the participants.

41. The NRC data shows rapidly increasing LLRW burial costs followed by large, discrete jumps.

42. The utilities did not include a separate contingency factor in their calculation of escalation rates.

43. A 7.5% escalation rate for LLRW burial costs was adopted for PG&E by the Commission in D.00-02-046.

44. PG&E's use of a simple average in calculating escalation rates gives a 20% weighting to all five categories, while the equipment and materials category accounts for 29%, and the "other" category accounts for 6% of actual expenditures.

45. The participants agree that a DRI forecast should be used for escalation rates, except for LLRW burial cost escalation.

46. ORA's DRI forecasts are the most recent in the record.

47. When using DRI forecasts to estimate escalation rates, use of the value for the last forecasted year for subsequent unforecasted years gives additional weight to the last forecasted year.

48. There is no reason that the DRI forecast for the last forecasted year is any better than the forecast for other years.

49. The Commission adopts contingency factors for cost estimates when the work to be done, and the requirements that must be met to do the work, may change substantially over time.

50. The escalation rate is an estimate of the rate of change in the cost of specified work.

51. The Commission routinely adopts forecasts of cost increases, in general rate cases for example, without applying contingency factors.

52. The NRC LLRW burial cost data shows significant jumps, and has no data for some years.

53. ORA has not demonstrated that its recorded LLRW burial cost increases from 1996 to the present provide a better basis for estimation than the NRC data used by the utilities.

54. It is uncertain where the LLRW will be buried, and at what cost.

55. LLRW burial costs are no less certain now than they were when the Commission adopted a 7.5% LLRW burial cost escalation rate for PG&E in D.00-02-046.

56. The midpoint of the range of LLRW burial cost escalation rates recommended by the participants is 7.5%.

57. The utilities acknowledge that LLRW burial costs could increase substantially due to imposition of state fees or taxes upon LLRW imported from other states such as California.

58. The midpoint of the range of estimated LLRW burial costs proposed by the parties is $240 per cubic foot.

59. The utilities have done a more comprehensive analysis of decommissioning costs, especially for SONGS 2&3, than PG&E.

60. The utilities' proposed 21% contingency factor for SONGS 2&3 is unopposed.

61. Palo Verde has not entered into a detailed planning phase for imminent shutdown and decommissioning.

62. SCE's use of its decommissioning experience and knowledge to refine its estimate for Palo Verde, as it has for SONGS 2&3, should lead to some reduction in uncertainty and, therefore, some reduction in the contingency factor below the 40% proposed by SCE.

63. There is not necessarily a direct relationship between an increase in the decommissioning cost estimate, and a reduction in the contingency factor.

64. The fact that SONGS 2&3 are estimated to begin decommissioning in 2022, and Palo Verde is estimated to begin decommissioning in 2024-2027, suggests the use of a contingency factor for Palo Verde of less than 40%.

65. Use of the 21% contingency factor used for SONGS 2&3 would be inappropriate for Palo Verde.

Conclusions of Law

1. Pursuant to D.99-06-007, the SONGS 1 $91 million decommissioning work completed as of December 31, 2001 is reasonable.

2. The Commission should adopt the utilities' $531 million estimate for SONGS 1 remaining decommissioning work, and authorize them to access up to 90% of the estimate from the trusts to pay for the decommissioning work.

3. Since the utilities' request for authority to use tax benefits retained in the non-qualified trust fund to continue SONGS 1 decommissioning work was approved by D.99-06-007, and is unopposed, it should be approved.

4. SCE, SDG&E, and PG&E's realized rates of return for their trusts will be different.

5. The Commission should adopt a uniform set of rate of return projections for all three utilities.

6. D.99-06-007 approved a settlement and, therefore, is not a precedent.

7. The Commission should adopt a 10.5% pre-tax return on equities.

8. The Commission should adopt 6.0% pre-tax return on fixed assets.

9. Although forecasts of escalation rates are speculative by nature, it makes sense to use the most recent available forecasts.

10. The Commission should adopt the DRI forecasts used by ORA, which are the most recent DRI forecasts in the record, for use in determining escalation rates.

11. When using DRI forecasts for estimating escalation rates, the average rate for the forecast period should be used for the subsequent unforecasted years.

12. The Commission should not adopt a separate contingency factor for escalation rates.

13. The NRC LLRW burial cost data does not provide a good basis for estimating LLRW burial cost escalation rates.

14. The Commission should adopt a 7.5% escalation rate for LLRW burial costs.

15. Future LLRW burial costs are uncertain at best.

16. PG&E's estimate of LLRW burial costs is no better than the estimates prepared by the utilities.

17. Actual LLRW burial costs will lie within the range of estimates proposed by the participants.

18. The Commission should adopt LLRW burial costs of $200 per cubic foot.

19. The Commission should adopt the utilities' proposed 21% contingency factor for SONGS 2&3.

20. The Commission should adopt a 35% contingency factor for Palo Verde.

21. SCE should be authorized a revenue requirement of $32.848 million.

22. SDG&E should be authorized a revenue requirement of $6.692 million.

23. This decision should be effective immediately so that the revenue requirements adopted herein can be put into effect as soon as possible.

24. D.00-06-034 requires that decommissioning costs be allocated on an equal cents per kilowatt-hour basis.

25. The revenue requirements adopted herein should be implemented on an equal cents per kilowatt-hour basis.

ORDER

IT IS ORDERED that:

1. The following annual revenue requirements are adopted for Southern California Edison Company (SCE) for 2003-2005; $21.160 million for decommissioning of San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2&3), and $11.688 million for decommissioning of Palo Verde Nuclear Generating Station Units 1, 2, and 3.

2. The revenue requirement adopted for San Diego Gas and Electric Company (SDG&E) for 2003-2005 is $6.692 million for decommissioning of SONGS 2&3.

3. No revenue requirement is authorized for San Onofre Nuclear Generating Station Unit 1.

4. The revenue requirements adopted herein shall be put into rates on an equal cents per kilowatt-hour basis as required by Decision (D.) 00-06-034.

5. SCE and SDG&E shall file advice letters implementing the revenue requirements adopted herein no later than 30 days after the effective date of this decision.

6. Pursuant to D.99-06-007, the SONGS 1 $91 million decommissioning work completed as of December 31, 2001 is reasonable.

7. The utilities' $531 million estimate for SONGS 1 remaining decommissioning work is adopted.

8. The utilities are authorized to access up to 90% of the $531 million estimate from the trusts to pay for SONGS 1 remaining decommissioning work.

9. SCE and SDG&E's request for authority to use tax benefits retained in the non-qualified trust funds to continue SONGS 1 decommissioning work is approved.

10. This proceeding is closed.

This order is effective today.

Dated October 2, 2003, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I dissent.

/s/ CARL W. WOOD
Commissioner

I reserve the right to file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

ATTACHMENT A
SCHEDULE OF RULING AMOUNTS TABLES
SOUTHERN CALIFORNIA EDISON COMPANY

ATTACHMENT B

SCHEDULE OF RULING AMOUNTS TABLES

SAN DIEGO GAS & ELECTRIC COMPANY

Decision 07-01-003 (January 11, 2007)

 Mailed 1/12/07

Decision 07-01-003 January 11, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Southern California Edison Company and San Diego Gas & Electric Company for the 2005 Nuclear Decommissioning Cost Triennial Proceeding to Set Contribution Levels for the Companies' Nuclear Decommissioning Trust Funds and Address Other Related Decommissioning Issues.	Application 05-11-008 (Filed November 10, 2005)
Application of Pacific Gas and Electric Company in Its 2005 Nuclear Decommissioning Cost Triennial Proceeding.	Application 05-11-009 (Filed November 10, 2005)

(See Appendix A (Service List) for Appearances.)

FINAL OPINION ON 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

TABLE OF CONTENTS

APPENDIX B: SETTLEMENTS FOR NUCLEAR DECOMMISSIONING

FINAL OPINION ON 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

I. Summary

This decision adopts an all-party settlement for Southern California Edison Company (Edison) and San Diego Gas & Electric Company (SDG&E) which resolves all issues in a Joint Application (A.) 05-11-008. We also adopt a separate settlement for Pacific Gas and Electric Company (PG&E) in A.05-11-009 which resolves all ratemaking issues exclusive of the issues litigated by PG&E and a customer-intervenor, Scott Fielder. We decline to create an Independent Board of Consultants to oversee or advise on the decommissioning of Humboldt Unit 3. We do, however, provide guidelines applicable to all three applicants concerning the necessity to ensure that the utilities employ sufficient well-trained and experienced personnel to plan and direct the complex task of decommissioning a retired nuclear generating facility. We do not adopt Fielder's proposals concerning the storage costs of radioactive waste materials or contingency factors. We do, however, direct the parties to perform in-depth analyses of storage costs and contingencies for the next triennial proceedings for all three utilities.

II. Requests

A. Edison and SDG&E

In A.05-11-008, Edison & SDG&E request the Commission:

(1) find the $298 million (100% share, 2004$) cost of San Onofre Nuclear Generating Station (SONGS) Unit 1 decommissioning work completed between January 1, 2002 and June 30, 2005 is reasonable;

(2) find the updated $309 million (100% share, 2004$) SONGS Unit 1 decommissioning cost estimate for the remaining work is reasonable;

(3) find the updated $3,131 million (100% share, 2004$) SONGS Units 2 & 3 decommissioning cost estimate is reasonable;

(4) raise the Qualified Trust maximum equity percentage to 60%;

(5) raise the cap on investment management fees to 30 basis points;

(6) raise annual compensation retainer for non-company members of the Nuclear Decommissioning Trust Committee to $12,000; and

(7) allow a maximum 20% allocation of the total fixed income portfolio in the Qualified Trust to high yield bonds rated B or higher by Standard and Poors or B2 or higher by Moodys.

In addition, Edison requests the Commission:

(1) find the updated $739 million (Edison's share, 2004$) Palo Verde decommissioning cost estimate is reasonable;

(2) authorize rate recovery of its increased contribution of $57.8 million to its Nuclear Decommissioning Trust Funds for SONGS Units 2 & 3 and for Palo Verde Nuclear Generating Station Units 1, 2, & 3 (Palo Verde) through the Nuclear Decommissioning Cost Charge;

(3) authorize Edison to amend its Decommissioning Trust Agreements (Trust Agreements) to clarify that transfers of nonqualified nuclear decommissioning trust (Nonqualified Trust) assets to the qualified nuclear decommissioning trust (Qualified Trust), pursuant to Internal Revenue Code Section 468A(f), as amended by the Energy Policy Act of 2005, are permissible under the Trust Agreements, and to submit such amendments as may be required for Commission approval via advice letter filing;

(4) approve the transfer of funds from Edison's SONGS and Palo Verde Nonqualified Trusts to the corresponding SONGS and Palo Verde Qualified Trusts, pursuant to Internal Revenue

Code Section 468A(f), as amended by the Energy Policy Act of 2005; and

(5) authorize Edison to continue to use the tax benefits associated with deducting SONGS Unit 1 Nonqualified Trust amounts consistent with Ordering Paragraph 9 of Decision (D.) 03-10-015, including the tax benefits that may arise in connection with any transfer of funds from Edison's SONGS Unit 1 Nonqualified Trust to Edison's SONGS Unit 1 Qualified Trust as provided for in Internal Revenue Code Section 468A(f), to continue SONGS Unit 1 decommissioning work.

SDG&E requests the Commission authorize or approve:

(1) rate recovery of SDG&E's increased contributions of $12.05 million, excluding franchise fees and uncollectibles, to its nuclear decommissioning trust funds for SONGS Units 2 & 3;

(2) the use of $5.523 million of the over collection in SDG&E's Nuclear Decommissioning Adjustment Mechanism as a 12-month amortization to the nuclear decommissioning rate effective January 1, 2007;

(3) amending SDG&E's Trust Agreements to clarify that transfers of Nonqualified Trust assets to the Qualified Trusts pursuant to Internal Revenue Code Section 468A(f), as amended by the Energy Policy Act of 2005, are permissible under the Trust Agreements, and to submit such amendments as may be required for Commission approval via advice letter filing;

(4) transferring funds from SDG&E's SONGS Nonqualified Trust to the corresponding SONGS Qualified Trust; and

(5) SDG&E to continue to use the tax benefits associated with deducting SONGS Unit 1 Nonqualified Trust amounts consistent with Ordering Paragraph 9 of Commission D.03-10-015, including any tax benefits that may arise in connection with any transfer of funds from SDG&E's SONGS Unit 1 Nonqualified Trust to SDG&E's SONGS Unit 1 Qualified Trust as provided for in Internal Revenue

Code Section 468A(f) to continue SONGS Unit 1 decommissioning work.

B. PG&E

In a separate application, A.05-11-009, PG&E requests the Commission to authorize the collection, through Commission-jurisdictional electric rates, of the following amounts in 2007 through 2009 for decommissioning of Diablo Canyon and Humboldt Unit 3:

(1) $9.491 million and $0 for the Diablo Canyon Nuclear Decommissioning Trusts for Units 1 and 2, respectively (the 2005 revenue requirement is $0);

(2) $14.621 million for the Humboldt Unit 3 Nuclear Decommissioning Trust (the 2005 revenue requirement is $18.443 million);

(3) increase revenue requirements to cover the costs of operating and maintaining (O&M) the Humboldt Unit 3 site in a safe condition (SAFSTOR). Specifically, PG&E is requesting SAFSTOR revenue requirements of $13.232 million in 2007 from the authorized amounts of $10.836 million for 2005. PG&E is also requesting attrition for SAFSTOR expenses for 2008 and 2009;

(4) continue overall decommissioning revenue requirement levels currently in effect for 2005 through 2006, but to apply $12.376 million as revenue requirements attributable to SAFSTOR expenses, while contributing the remainder (after any applicable taxes) to the decommissioning trusts; and

(5) find that PG&E's activities with respect to two completed decommissioning projects – involving asbestos removal and plant systems and structures radiological characterization – were reasonable and prudent.

III. Procedural History

Notice of these two applications appeared in the Commission's Daily Calendar on November 16, 2005. The Commission preliminarily categorized them as ratesetting in Resolution ALJ 176-3162, dated November 18, 2005. The January 18, 2006 scoping ruling confirmed the categorization as ratesetting, and the need for hearings. The scoping ruling also consolidated the applications. Testimony was served by the Division of Ratepayer Advocates (DRA), the Federal Executive Agency (FEA), The Utility Reform Network (TURN), and Scott Fielder, a customer-intervenor, (Fielder). All parties served timely rebuttal and other supplemental testimony as allowed or required by the assigned Administrative Law Judge (ALJ). The two settlements were admitted as Exhibits 18 and 19 at evidentiary hearings.[1] These settlements resolved all issues for Edison and SDG&E in A.05-11-008 and resolved all issues except those litigated by PG&E and Fielder in A.05-11-009. This decision adopts the proposed transcript corrections requested in PG&E's June 5, 2006 Motion to Propose Transcript Corrections. Parties filed Opening Briefs or Comments on the Settlements on June 23, 2006, and Replies on July 14, 2006. The record is composed of all documents that were filed and served on parties. It also includes all testimony and exhibits[2] received at hearing.

IV. Scope and Issues

The first purpose of these proceedings is to establish just and reasonable rates to adequately fund the nuclear decommissioning trusts in place for the

[1] Exs. 18 and 19 have been updated and replaced in the formal files to include signature attachments and other minor edits or corrections. As no party objected to these changes, the exhibits are received in the record as modified. Edison filed a further correction and clarification on August 31, 2006 which we used in this decision.

[2] There were 110 exhibits received into evidence—many were large multi-chaptered documents sponsored by several witnesses.

benefit and protection of ratepayers. Secondly, we verify that Edison, SDG&E, and PG&E are in compliance with all prior decisions applicable to decommissioning. Finally, these proceedings determine whether the costs expended to-date to decommission SONGS Unit 1 and Humboldt Unit 3 were reasonable and prudent. To the extent necessary, these proceedings examined all underlying forecasts and assumptions to estimate the future costs of decommissioning the various nuclear generating stations; the costs and earnings associated with the decommissioning trust funds; the rate impacts of the Energy Policy Act of 2005, including all relevant changes to Internal Revenue Code Section 468A; and other relevant data, policies or laws and regulations. These proceedings included the standard reasonableness review of managerial decisions and actions by PG&E, Edison, and SDG&E as they have pursued decommissioning either Humboldt Unit 3 or SONGS Unit 1. PG&E supplemented its application and explicitly addressed consideration of an Independent Board of Consultants to oversee the decommissioning of Humboldt Unit 3. Finally, we considered whether or not to grant the request by Edison and SDG&E to pre-approve the cost forecast for the remaining work to decommission SONGS Unit 1.

V. Standard of Review

The applicants alone bear the burden of proof to show that the rates they request are just and reasonable and the related ratemaking mechanisms are fair.

For the purposes of these proceedings and as used in the scope above, we define reasonableness for decommissioning expenditures consistent with prior Commission findings, i.e., that the reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made.[3] However, with respect to Phase 1 SONGS 1 decommissioning work, the Commission in D.99-06-007 adopted a ratemaking settlement that included a presumption that the utilities' conduct is reasonable in performing Phase 1 SONGS 1 decommissioning work if the scope of the work completed and the most recently approved SONGS 1 decommissioning cost estimate bound the costs incurred. (Settlement § 4.2.2.2.c., at 86 CPUC2d 604, 620.)

In order for the Commission to consider the proposed settlements in these proceedings as being in the public interest, the Commission must be convinced that the parties had a sound and thorough understanding of the applications and all of the underlying assumptions and data included in the record. This level of understanding of the applications and development of an adequate record is necessary to meet our requirements for considering any settlement, as discussed below. The disputed issues for PG&E are resolved in this decision based on the evidence in the record.

VI. Discussion of Settlements

A. Standard for Approval of a Settlement

Rule 51.1(a)[4] provides:

> Parties to a Commission proceeding may stipulate to the resolution of any issue of law or fact material to the proceeding, or may settle

[3] See for example, D.02-08-064, dated August 22, 2002, *mimeo.*, pp. 5-8.

[4] The Commission adopted a revised Rule 51, as Rule 12, effective September 13, 2006, which does not materially differ from the substance of the old rule. Parties settled under then-applicable Rule 51, which we cite herein.

> on a mutually acceptable outcome to the proceeding, with or without resolving material issues. Resolution shall be limited to the issues in that proceeding and shall not extend to substantive issues which may come before the Commission in other or future proceedings.

Rule 51.1(e) has, as a further requirement:

> The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is <u>reasonable in light of the whole record, consistent with law, and in the public interest</u>. (Emphasis added.)

In short, we must find the settlement comports with Rule 51.1(e) which requires a settlement to be "reasonable in light of the whole record, consistent with law, and in the public interest." We address below whether the settlements meet these three requirements.

B. Reasonable in Light of the Whole Record

We have reviewed the evidence in the record, considered the scope and thoroughness of the review by all active parties, especially DRA, TURN, and FEA (for SDG&E's interests). In particular, DRA, TURN, and FEA conducted detailed examinations. Having reviewed the prepared testimony of all parties, we find that the proposed settlements are both within the range of reasonable findings if the applications had been fully litigated. Therefore we can find the settlements to be reasonable in light of the whole record. The items contested between PG&E and Fielder are considered separately in this decision: however, absent Fielder's objections, the settlement by PG&E with DRA and TURN is otherwise reasonable in light of the whole record.

C. Consistent With Law

Nothing in either settlement is inconsistent with the law, and the settlement process was consistent with Rules 51 *et seq.* Therefore we can find the settlements to be consistent with applicable law.

D. In the Public Interest

There was no guarantee that litigation of the issues raised by the parties would have resulted in any adjustment to the decommissioning revenue requirements as significant as proposed in the two settlements which are acceptable to all parties. The settlements saved time and resources, and achieved results within the range of reasonable litigation outcomes. The need for decommissioning funding was not at issue in this proceeding—that was determined when the funds were established in compliance with state and federal requirements. Therefore, since there is an uncontested need for funding future decommissioning costs and the funding in the settlements is consistent with the record, we find the settlements for decommissioning funding to be in the public interest. Similarly, the need for actual decommissioning activities for SONGS Unit 1 and Humboldt Unit 3 were uncontested. The settlements on the reasonableness of actual costs are consistent with the record; therefore we find the settlements for decommissioning funding to be in the public interest.

E. Uncontested Settlement

A further standard is articulated in *San Diego Gas & Electric* 46 CPUC 2d 538 (1992), and applies to all-party settlements. As a precondition to approving such a settlement, the Commission must be satisfied that:

1. The proposed all-party settlement commands the unanimous sponsorship of all active parties to the proceeding.

2. The sponsoring parties are fairly representative of the affected interests.
3. No settlement term contravenes statutory provisions or prior Commission decisions.
4. Settlement documentation provides the Commission with sufficient information to permit it to discharge its future regulatory obligations with respect to the parties and their interests.

We can answer all four requirements in the affirmative for Edison and SDG&E's ratemaking settlement. Questions 2 through 4 are true for PG&E's contested settlement.

VII. Settlement Provisions

A. Edison and SDG&E

Pursuant to the proposed Settlement Agreement, Appendix B and Appendix C, Edison and SDG&E filed on July 14, 2006 an update to the settlement contributions and the overall revenue requirements, using May 31, 2006, Decommissioning Trust Fund liquidation values (rather than March 31, 2006), because the May 31, 2006 values were not yet available when the parties entered into the Settlement. The settling parties had an opportunity to review this update and have made no objection. We will therefore rely on this and later updates in evaluating the proposed settlement. In the July 14, 2006 update, Edison and SDG&E provided new contributions and revenue requirements.[5] Edison subsequently discovered certain errors in its July 14, 2006 calculations of the settlement amounts. First, the settling parties agreed to a 21% contingency

[5] The contribution is the amount placed into the trust fund. The revenue acquirement includes other related costs as well as the contribution.

factor, in lieu of the requested 35% contingency factor, which was not used in the calculation of the settlement amounts. Second, the settlement amounts needed to correctly reflect the pro-ration of the 2006 contribution for Palo Verde Nuclear Generating Station Unit 3 at May 31, 2006, rather than March 31, 2006, as a result of updating the Decommissioning Trust Fund liquidation values. Third, the settlement amounts need to correctly reflect the correct SONGS escalation factors, which were not updated to the escalation factor update agreed to in the settlement. We commend the settling parties for diligently reviewing the settlements and for recognizing the need for corrections. On August 31, 2006, Edison and SDG&E filed a motion requesting the Commission accept further corrections and clarifications to the settlements. We grant the motion and receive the corrections. The other settling parties have agreed with the following corrections to the settlement:

Edison's Qualified Nuclear Decommissioning Trust Funds Allocation of Contributions and Revenue Requirement Updated Appendix B ($000)						
	SONGS 2	SONGS 3	Palo Verde 1	Palo Verde 2	Palo Verde 3	Total
Contribution	$16,984	$10,797	$5,067	$5,663	$3,728	$42,239
Revenue Requirement	$17,185	$10,925	$5,127	$5,773	$3,773	$42,739

SDG&E's Qualified Nuclear Decommissioning Trust Funds Allocation of Contributions and Revenue Requirement Updated Appendix C ($000)			
	SONGS 2[6]	SONGS 3	Total
Contribution	$5,290	$4,060	$9,350
Revenue Requirement	$5,364	$4,117	$9,481

[6] This includes qualified and non-qualified trust amounts.

The key terms of the Settlement Agreement were summarized in the June 23, 2006 Joint Statement for Edison and SDG&E[7] as follows:

> (A) the March 2006 25-year Global Insight forecast for projected pre-tax rate of returns for the years 2007 through 2029 to be assumed for the equity and bond portions of the decommissioning trust assets,
>
> (B) the March 2006 25-year Global Insight forecast to be assumed for escalation rates,
>
> (C) May 31, 2006, Decommissioning Trust Fund liquidation values,
>
> (D) a 60% holding in equities in the Qualified Trusts as of the presumed date of January 1, 2007, provided that the Commission approves a maximum allocation of 60% equities, and [Edison] SCE's/SDG&E's Nuclear Decommissioning Trust Investment Committee approves an allocation of 60% equities, for the Qualified Trusts, and
>
> (E) for SCE, a 21% contingency factor on all components of the Palo Verde decommissioning cost estimate, except estimated low-level radioactive waste ("LLRW") burial costs, to which no contingency factor is applied.
>
> Appendix B and C of the Settlement Agreement contain an exemplar table identifying the allocation of the Revenue Requirement and trust contribution for SCE and SDG&E for SONGS 2&3, and, for SCE, Palo Verde with the modifications described in subsections (A), (B), (D) and (E) above, ... SCE and SDG&E agreed in the Settlement Agreement to file an update of Appendix B and C with their reply brief on July 14, 2006 in this docket that reflects the May 31, 2006 Decommissioning Trust Fund liquidation values (and a reduced percentage of equities for the Qualified Trusts if the 60% allocation is

[7] Joint Statement of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902-E), Division of Ratepayer Advocates, Federal Executive Agencies and The Utility Reform Network in support of Settlement (Joint Statement for Edison and SDG&E).

not approved by the Nuclear Decommissioning Trust Committee). The Settlement Agreement requests that the Commission find the allocations exemplified in Appendices B and C and the corresponding update to be submitted on July 14, 2006 to reflect May 31, 2006 Decommissioning Trust Fund liquidation values (and a reduced percentage of equities for the Qualified Trusts if the 60% allocation is not approved by the Nuclear Decommissioning Trust Committee), to be reasonable.

- SCE and SDG&E should be authorized to:
  - Raise the Qualified Trust's maximum equity percentage to 60%,
  - Raise the cap on investment management fees to 30 basis points, and
  - Raise the annual compensation retainer for non-company members of the Nuclear Decommissioning Trust Committee to $12,000.

- SCE and SDG&E should be authorized to amend their respective Decommissioning Trust Agreements to clarify that transfers of assets to the Qualified Trusts (including transfers from the Nonqualified Trusts), pursuant to Internal Revenue Code Section 468A(f), as amended by the Energy Policy Act of 2005, are permissible under the Trust Agreements, and to submit such amendments as may be required for Commission approval via advice letter filing.

- The Commission should approve the transfer of funds to the corresponding SONGS and Palo Verde Qualified Trusts (including transfers from the Nonqualified Trusts), as may be permitted pursuant to Internal Revenue Code Section 468A(f), as amended by the Energy Policy Act of 2005, as authorized by the Internal Revenue Service.

- SCE and SDG&E should be authorized to continue to use the tax benefits associated with deducting SONGS 1 Nonqualified Trust amounts consistent with Ordering Paragraph No. 9 of D.03-10-015, including the tax benefits that may arise in connection with any transfer of funds from SCE's/SDG&E's SONGS 1 Nonqualified

Trusts to SCE's/SDG&E's SONGS 1 Qualified Trusts as provided for in Internal Revenue Code Section 468A(f), to continue SONGS 1 decommissioning work.

• SDG&E should be authorized to apply $2.79 million of the overcollection in its Nuclear Decommissioning Adjustment Mechanism as a 12-month amortization to the nuclear decommissioning rate effective January 1, 2007, to offset the impact of the increase in the Nuclear Decommissioning revenue requirement in 2007.

• As part of the next NDCTP, SCE and SDG&E will evaluate and address in their application and opening testimony: (1) whether any SONGS 1 decommissioning trust funds are not anticipated to be needed at that time for remaining SONGS 1 Decommissioning Work; and (2) whether any such funds can and should be transferred to SONGS 2&3 Decommissioning Trusts for use to fund SONGS 2&3 decommissioning, contingent upon a favorable ruling from the IRS allowing the transfer, if necessary, and any necessary approvals by the Nuclear Regulatory Commission or other agencies.

• SCE and SDG&E agree that if SCE and SDG&E, respectively, receive money from the DOE in settlement of their DOE spent fuel litigation within three years of the effective date of this Agreement, SCE and SDG&E will seek a favorable ruling from the IRS to deposit certain monies received from the DOE into their respective decommissioning trust accounts. After receiving a favorable ruling from the IRS, SCE and SDG&E will deposit the money received from the DOE (less external litigation costs) that is associated with funds required for work included in the decommissioning cost estimates (but not money associated with current SONGS 2&3 operations or off-site storage of SONGS 1 used fuel at Morris, Illinois) into their respective appropriate decommissioning trust accounts. SCE and SDG&E will each file an Advice Letter within 120 days of the date of deposit of the funds into the decommissioning trusts to update their respective annual contributions accordingly.

• The Commission should adopt as reasonable: (i) the $298 million (100% share, 2004$) cost of SONGS 1 Decommissioning Work completed between January 1, 2002 and June 30, 2005, and (ii) the updated $309 million (100% share, 2004$) SONGS 1 decommissioning cost estimate for Remaining Work.

• The Commission should adopt as reasonable the updated decommissioning cost estimates for SONGS 2&3 and Palo Verde set forth by SCE and SDG&E in the Joint Application (other than the revision to the Palo Verde decommissioning cost estimate, reflecting a reduction in the contingency factor for non-LLRW burial components of the cost estimate from 35% to 21%).

• SCE will provide, as part of its tax testimony in the next NDCTP, a memorandum account that would track the time value of money associated with any net overpayment of estimated income tax payments of its Nuclear Decommissioning Trusts. This memorandum account will compare the estimated tax payments actually made with the amounts required to be paid in each quarterly period based upon the tax returns as filed. An interest rate equal to the assumed after-tax rate-of-return underlying the annual contribution authorized for each trust account will be applied to this difference for the period outstanding. These interest amounts will be cumulated and constitute the balance in this memorandum account. It will be subject to review and reduce the revenue requirement to be authorized in the next proceeding. (June 23, 2006 Joint Statement, pp. 4-8, footnotes omitted.)

The parties assert that in reaching this settlement, they "compromised strongly held views"; and that in all other respects, the settlement comports with the Commission's requirements for adoption of a settlement.

Key Comparisons of Settlement with Applications			
	Application	Settlement	Difference
Edison's Trust Contributions	$57.8 million	$42.2 million	$15.6 million -27%
SDG&E's Trust Contribution	$12.05 million	$9.35 million	$2.7 million -22.4%
SONGS 1 Costs	$298 million (100%)	$298 million (100%)	0
SONGS 1 Forecast	$309 million (100%)	$309 million (100%)	0
Palo Verde Forecast	$738.852 million	$696,003 million	$42.849 million -5.8%

Qualified Trust Equity Percentage	60% max.	60% max.	0
Investment management Fee	30 Basis points max.	30 Basis points max.	0
Committee Retainer	$12,000 p.a.	$12,000 p.a.	0

The Commission does not unravel a settlement unless there is significant problem with the outcome as a whole—in which case the settlement would fail the public interest test discussed elsewhere. This settled outcome is within the range of plausible litigation outcomes. Except for SONGS Unit 1, these plants are not in active decommissioning: in fact, they are operational and are even subject to proceedings which may extend the service life by replacing the steam generators. (See D.05-12-040.) We are therefore less concerned now about under-funding than we will be as these plants approach retirement. Our overriding concern with decommissioning is to ensure that the trust funds are sufficient to retire the plants pursuant to a reasonable plan and that the funds are recovered equitably from customers throughout the plants' service lives. We find the settlement applicable to Edison and SDG&E to be reasonable.

B. PG&E

The key terms of PG&E's Settlement Agreement were summarized as follows:

a. $13.234 million in 2007 for Humboldt Unit 3 SAFSTOR, an additional amount for attrition of $155,000 beginning January 1, 2008 and, an additional $16,000 beginning January 1, 2009.

b. Beginning in 2007, for a 3-year period, $1.827 million for Diablo Unit 1 trust fund and $0 for the Diablo Unit 2, annually.

c. Beginning in 2007, for a 3-year period, $11.915 million for Humboldt Unit 3 trust fund.

d. Requests that the CPUC approve a transfer of funds from the Diablo Unit 2 Trust to the Diablo Unit 1 Trust. The transfer will be calculated based on and/or subject to a) the authorized trust contribution revenue for Diablo Unit 1; b) PG&E's 2007 Ruling Amount Update; c) the amount of excess funds in the Diablo Unit 2 Trust; and d) the approval of the CPUC, Nuclear Regulatory Commission and the Internal Revenue Service.

e. Additional safeguards for the decommissioning trusts (Settlement, para. 12).

f. Additionally, the following modeling assumptions were used in the settlement:

1. Low level radioactive waste Class A Burial Rate: $248 per cubic foot (In 2004 dollars)
2. Diablo Unit 2 Decommissioning Start Date: 2024
3. Humboldt Unit 3 Decommissioning Start Date: 2009
4. Diablo Contingency Factor: 35%
5. Humboldt Unit 3 Contingency Factor: 25%
6. Burial Escalation: 7.5%
7. Non-Burial Escalation: As presented in PG&E's A.05-11-009 Prepared Testimony filed November 10, 2005, including calculation methodology
8. Trust fund balance: Update as of December 31, 2005
9. Equity Turnover Rate (Qualified): 23.65%
10. Equity Turnover Rate (Non-Qualified): 24.49%
11. Pre-Tax, Before Fees Return on Equity: 8.5%
12. Pre-Tax, Before Fees Return on Fixed Assets: 5.8%
13. DCPP Equity/Bond Allocation: 57%/43% (Subject to Commission approval)
14. DCPP Equity Ramp Down: 1-Year Delay, Begin in 2020
15. Transfer of Humboldt Non-Qualified trust balance and associated tax benefits to Humboldt Qualified

Key Comparisons of Settlement with Applications

	Application	Settlement	Difference
PG&E's Diablo 1 & 2 Trust Contributions	$9.491 million	$1.827 million	$7.664 million -80.75 %
Humboldt 3 Trust Contribution	$14.621 million	$11.915 million	$2.706 million -18.5%
Humboldt 3 forecast SAFSTOR 2007	$13.232 million	$13.234 million	$0.002 million

VIII. Independent Board of Consultants

The scoping ruling required PG&E to supplement its application to address Ordering Paragraph 7 in D.00-02-046,[8] for the consideration of an "Independent Board of Consultants" to oversee the decommissioning of Humboldt Unit 3:

> At least six months before the date that full scale decommissioning of Humboldt Bay Unit 3 begins, and no later than 30 days after any order of the Nuclear Regulatory Commission authorizing an on-site dry cask storage plan, PG&E shall file an application before this Commission to initiate consideration of the establishment of an Independent Board of Consultants to oversee the decommissioning of Humboldt Bay Unit 3. Until such time as an Independent Board of Consultants is established, PG&E shall continue outreach efforts to ensure that the Redwood Alliance and the Eureka community are kept informed about the status of the plant and decommissioning of it." (*Mimeo.*, D.00-02-046, p. 543.)

The issue was in the scoping ruling and PG&E was required to supplement its prepared testimony, as a result of Fielder's timely protest. PG&E proposed in its supplemental testimony that no committee was necessary. Fielder formerly represented the Redwood Alliance, which he asserts is

[8] D.00-02-046 in PG&E's test year 1999 general rate case, A.97-12-020.

essentially defunct at this time. He pursued the issue of an Independent Board of Consultants as an interested customer.

A. PG&E's Position

PG&E opposes an Independent Board of Consultants. PG&E argues first that it plans to contract for the decommissioning of Humboldt Unit 3 with established firms that have appropriate experience in decommissioning work. Second, PG&E asserts that subsequent decommissioning activities for Humboldt Unit 3 are "rather straight forward . . . with little room for deviation."[9] PG&E suggests that the Nuclear Regulatory Commission determines all requirements for radioactive material disposal and site release for other use. Therefore, there is only limited discretion for PG&E and its contractors.

PG&E argues it applies economical and efficient methods to ensure prudent decisionmaking and oversight of decommissioning expenditures. PG&E's current practice is to maintain separate accounting orders to record the costs of the dry cask storage activities and related transactions with the decommissioning trusts. This separate accounting facilitates monitoring by the Commission staff. PG&E also proposes community outreach on the decommissioning effort.

PG&E points out that it must submit an updated decommissioning cost estimate for any remaining decommissioning activities in subsequent triennial reviews. In addition, PG&E must submit a comparison of the most recently completed Humboldt Unit 3 decommissioning work, and the costs incurred, to the previous forecast of Humboldt Unit 3 decommissioning cost estimate. PG&E

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[9] Ex. 6, p. 7-3.

must persuasively demonstrate that material variances are reasonable. PG&E is therefore opposed to an Independent Board of Consultants that it believes would not be cost effective and would add to decommissioning expenses payable by the trusts. (See Ex. 6, pp. 7-2 - 7-4.)

B. Fielder's Position

Fielder cites to Pub. Util. Code §§ 1091 - 1102 which provides for a construction project board of consultants and argues that decommissioning is very similar to large-scale construction in that decommissioning is also a complex project. (Fielder Reply Brief, p. 2, and footnote 1.) Fielder suggests the Diablo Canyon Independent Safety Committee (Diablo Safety Committee) also serves as a model, at least for budgetary purposes.[10] Fielder argues that PG&E's estimates for Humboldt's decommissioning are inflated and that without an independent board, PG&E will be deemed prudent while spending too much. Additionally, Fielder argues that intervenors, including DRA, lack the expertise to effectively challenge PG&E's cost estimates or actual decommissioning costs in the triennial reviews.

C. Discussion

We agree in principle with Fielder on the necessity to ensure that PG&E uses sufficient well-trained and experienced personnel to plan and direct the complex task of decommissioning a retired nuclear generating facility. PG&E is primarily an operating gas and electric distribution utility and not primarily an architect-engineer continuously engaged in complex construction and removal

[10] Created as part of the ratemaking settlement for Diablo Canyon in D.88-12-083. (30 CPUC 2d, 189.)

projects. This is also true for Edison and SDG&E; therefore our findings, below, are applicable to them as well, on the need for engaging and using sufficient well-trained and experienced personnel suitable to decommissioning a retired nuclear generating facility.

The Diablo Safety Committee is not an appropriate model: it is an after-the-fact investigative body that may be an incentive for safe operations (or deterrent to unsafe operations) but it does not immediately affect or control operating decisions.

> The Diablo Canyon Independent Safety Committee ("DCISC") was established as a part of a settlement agreement entered into in June 1988 between the Division of Ratepayer Advocates of the California Public Utilities Commission ("PUC"), the Attorney General for the State of California, and Pacific Gas and Electric Company ("PG&E") concerning the operation of the two units of PG&E's Diablo Canyon Nuclear Power Plant ("Diablo Canyon"). The agreement provided that:
>
> An Independent Safety Committee shall be established consisting of three members, one each appointed by the Governor of the State of California, the Attorney General and the Chairperson of the California Energy Commission, respectively, serving staggered three-year terms. The Committee shall review Diablo Canyon operations for the purpose of assessing the safety of operations and suggesting any recommendations for safe operations. <u>Neither the Committee nor its members shall have any responsibility or authority for plant operations, and they shall have no authority to direct PG&E personnel.</u> The Committee shall conform in all respects to applicable federal laws, regulations and Nuclear Regulatory Commission ("NRC") policies. (http://www.dcisc.org/general_information/general_information.html - the Diablo Safety Committee's website, emphasis added.)

There is an inherent conflict between the roles of consultants authorized by a regulator and managers who must account for their actions to a regulator. A consultant is "a person who provides expert advice professionally" whereas, a manager is "a person who manages an organization, group of staff."[11] A manager may get conflicting advice from varions sources and must make a decision on which advice is best for the circumstances.

If the Commission were to authorize an Independent Board of Consultants, we would have to very clearly delineate: the selection criteria; role and obligations of the board; the mechanical operations of the board; the process to quickly resolve disagreements between PG&E and the board; and, no doubt, numerous other details. Fielder does not provide us with any of these details, and under cross-examination, the sponsoring witness could not suggest any of the details for a viable Independent Board of Consultants framework for us to consider.[12] We do not consider §§ 1091 *et seq.* to be sufficient detailed operating guidelines to integrate a board with PG&E's management. Section 1098, for example, describes an after-the-fact review, including quarterly reports comparing actual to forecast results. These provisions suggest that such a board advises the Commission and does not control or advise PG&E prior to actual activities (for either new construction or dismantling major structures).

In order to satisfy the Commission, the utility must demonstrate that its actions can be deemed "reasonable and prudent." The Commission has found:

> The term 'reasonable and prudent' means that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known

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[11] Compact Oxford English Dictionary, online, http://www.askoxford.com/?view=uk.

[12] The Reply Brief however relies extensively on the analogy of a construction project board as cited to §§ 1091 *et seq.*

> or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost effectiveness, reliability, safety, and expedition.
>
> A 'reasonable and prudent' act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction. (24 CPUC 2d, 486.) (Emphasis added.)

Defining reasonable and prudent as good utility practices is a tautology. To properly manage the decommissioning process, to be reasonable and prudent, by using good utility practices, as required by this Commission, a utility must show (in this narrow instance) that it sought and used personnel who possessed the available and necessary skills, experience and knowledge to perform the task. So to reasonably undertake decommissioning a nuclear generating plant, PG&E (as well as Edison and SDG&E) must employ properly trained experts who have experience relevant to decommissioning a nuclear plant to plan and perform the decommissioning. People with this skill set and experience may or may not be on the typical electric utility's staff. Therefore we expect PG&E to demonstrate in all subsequent decommissioning-related proceedings that throughout the decommissioning of Humboldt (and later for Diablo) it sought out and acquired the services of well-trained and experienced personnel appropriate to the tasks. We expect PG&E to identify, and aggressively pursue employing, the right people for the job. We need not care whether these people are employees of PG&E or contractors: that is an operating decision best resolved by the utility. Edison and SDG&E are also obliged as an integral part of good utility practices to demonstrate that in decommissioning SONGS Unit 1 that they engaged the right people for the job.[13]

D. Conclusion

An Independent Board of Consultants would obscure PG&E's overriding obligation to properly manage its decommissioning obligations. We are not competent, nor are our processes timely, to referee complex technical disagreements between PG&E's staff and an outside board on decommissioning issues. By contradistinction, the Nuclear Decommissioning Trust Funds' management committees are composed of utility officers and Commission-approved outside experts that explicitly have the responsibility to manage the trust funds' investments. Further, The Diablo Safety Committee does not operate the plant or consult on its management and therefore it is not a good model to justify the Independent Board of Consultants.

The proposed Board of Independent Consultants would not supplant and assume PG&E's responsibilities for decommissioning Humboldt Unit 3. Therefore, it is far preferable that PG&E must demonstrate in subsequent triennial reviews that it engaged as either employees, contractors, or consultants, people trained to plan and perform a decommissioning, and who have experience applicable to decommissioning a nuclear plant. We also find that this obligation applies to Edison and SDG&E in subsequent triennial reviews of decommissioning activities.

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[13] This discussion focuses narrowly on the desired skills and experience of certain necessary decommissioning personnel and is not an all-encompassing discussion of the total obligations that comprise reasonable and prudent managerial actions for decommissioning a nuclear power plant.

IX. Waste Storage Facilities and Cost

PG&E forecast its decommissioning costs for low level radioactive waste disposal and storage relying on facilities currently in use, but which may be closed to it when PG&E requires actual storage service. Fielder proposes that costs are likely to be much higher for any new storage facility. For low level radioactive waste, PG&E projected the cost of burial disposal at $248 per cubic foot (c.f.) but Fielder argued it should be set at $509 per c.f. as previously approved by the Commission (D.00-02-046 at p. 379, and cited in Fielder's Opening Brief, p. 1). Fielder estimates this would increase overall decommissioning cost for each plant by approximately $50,000,000 to $1,000,000,000. (Opening Brief, p. 1, and pp. 5-7.)

A. Discussion

There is little certainty about low level waste disposal, except we know in July 2008 the Barnwell facility will no longer accept waste from Non-Atlantic Compact states, which excludes the California utilities. (Ex. 11, pp. 24-27; and Ex. 21, pp. 14-18.) PG&E proposes $248 per c.f., escalated based on prior triennial reviews. Fielder argues that it is much more likely in the future the waste storage rates will be higher than Barnwell's cost, rather than lower, therefore the allowance should at least be set at $509 per c.f. Fielder believes that a potential Southwestern Compact facility would have costs even higher than $509 per c.f. (Opening Brief, p. 5.)

The settling parties, PG&E, DRA, and TURN, offer no compelling counter-argument in their joint reply brief, except to point out firstly that DRA proposed a composite rate of $140 per c.f., which we find, the settlement notwithstanding, to be without merit considering the closure of Barnwell and the uncertainty of the future. The settling parties' second reason to oppose Fielder's recommendation is the uncertainty of his estimate. This argument is two-edged and the perhaps sharper edge cuts against PG&E's proposed use of the unavailable but lower Barnwell costs: PG&E's proposal is lower than previous Southwestern Compact facility estimates for a now more uncertain future.

We know DRA's rate is too low. We know PG&E's rate is for a service that will not be available. Fielder's proposed rates are also speculative. Our obligation is to equitably collect sufficient money over the plants' service lives to adequately fund competently managed trust funds for reasonably managed and a well-planned decommissioning of nuclear generating plants when they are retired from service.

One option would be to split the difference: modify the settlement and substitute a mid-point of $378.50 between PG&E's estimate of $248 and Fielder's $509 proposal. A second more conservative approach would be to adopt Fielder's estimate for the most assurance that we do not under-fund the trusts. The ratepayers are ill served by any expedient but inaccurate estimate. We cannot isolate a storage cost component within the settlement—and if we try, we would thereby abrogate the parties' other trade-offs within the settlement. We can, however, accept the settlement for now, and look to the future to impress on PG&E, DRA, and all parties, including Edison and SDG&E, that no one's forecast was very persuasive. We have the benefit of some time before we need the trusts' proceeds for most of the plants and therefore we can rely on the current settlements until the next triennial review. For the next proceeding, we direct all parties to conduct a thorough and complete research and analysis, and then err on the conservative (high estimate) side, when forecasting waste storage costs. This finding is applicable to all three utilities. If there is no more certainty regarding western utilities' storage options during the next triennial review, then we expect parties to conservatively estimate low level waste storage costs. The parties may also make any additional recommendations on the appropriate allowance for waste storage costs.

X. Contingency

The proposed settlement incorporates a 35% contingency factor for Diablo Canyon and 25% for Humboldt Unit 3.[14] Fielder proposes that we should modify the settlement and use a 40% factor relying primarily on two issues: (1) the adopted contingency has been declining from a high of 50% in 1987 (24 CPUC 2d 15, 20) to 40% in 1995 (63 CPUC 2d 571, 613-614) and now the settling parties propose 35%; and (2) because of the Barnwell closure, waste storage costs are much more uncertain. (It is not clear whether Fielder would trade-off his storage estimate for his increased contingency, but there is a "belt and suspenders" element to the cautious recommendation of both.) A declining contingency, if properly determined, could reflect the improved accuracy of the decommissioning estimates based on more industry experience and being closer to the need for decommissioning. A contingency has an effect in early years of acting like an accelerated funding by over-accruing contributions in addition to its intended purpose of protecting against errors and unforeseen costs in the decommissioning estimate.

Again we are faced with a choice of whether or not to piecemeal the settlement. We will accept the settlement but in the next proceeding we direct all parties to conduct a thorough and complete research and analysis, and then err

[14] Contingency: (1) A future event or circumstance which is possible but cannot be predicted with certainty. (2) A provision for such an event or circumstance. (3) The absence of certainty in events. (Compact Oxford English Dictionary, online.)

on the conservative (high estimate) side, when forecasting a contingency factor. The parties may also make any additional recommendations on the appropriate allowance for contingencies. This finding is applicable to all three utilities.

XI. PG&E's Settlement is Reasonable

The Commission does not unravel a settlement unless there is significant problem with the outcome as a whole—in which case the settlement would fail the public interest test discussed elsewhere. This settled outcome is within the range of plausible litigation outcomes. Except for Humboldt Unit 3, these plants are not in active decommissioning. We are therefore less concerned now about under-funding than we will be as Diablo Units 1 and 2 approach retirement. Our overriding concern with decommissioning is to ensure the trust funds are sufficient to retire the plants pursuant to a reasonable plan and that the funds are recovered equitably from customers throughout the plants' service lives. We find the settlement applicable to PG&E to be reasonable.

XII. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 and Rule 14.2(a) of the Commission's Rules of Practice and Procedure (Rules). Comments were filed on November 20, 2006, by Edison and SDG&E, and separately by SDG&E, PG&E, DRA, and Fielder. Replies were filed by Edison and SDG&E, PG&E, and DRA on November 27, 2006. We have reviewed the comments and have made changes to the decision as appropriate.

XIII. Assignment of the Proceedings

Michael R. Peevey is the assigned Commissioner and Douglas M. Long is the assigned ALJ in these proceedings.

Findings of Fact

1. The Edison and SDG&E settlement is uncontested and resolves all disputed issues.

2. The PG&E settlement is uncontested except for the issues litigated by PG&E and Fielder.

3. The settlements resolve all of the disputed issues among the settling parties.

4. The active parties in the proceeding are representative of the stakeholders, and each has ably and vigorously pursued the interests of its constituency.

5. The proposed settlements' results are within the range of reasonable findings if the applications had been fully litigated on the parties' testimony.

6. An Independent Board of Consultants would interfere with PG&E exercising its obligations to efficiently and reasonably manage the decommissioning process.

7. Good utility practices would require a utility to engage a sufficient staff with appropriate expert training and experience to decommission a nuclear generation plant. This expert staff could be permanent staff, contractors or consultant staff.

8. Further detailed analysis and study is needed before the Commission can adopt reasonable future estimates for low level radiation waste storage.

9. Further detailed analysis and study is needed before the Commission can adopt reasonable future estimates for contingency factors in the decommissioning cost forecasts.

Conclusions of Law

1. Rules 51 *et seq.*, applicable during the pendency of this proceeding, should be used to review the settlement agreement.

2. The settlements for Edison and SDG&E meet the criteria of an uncontested settlement under Rule 51(f) and *San Diego Gas & Electric* 46 CPUC 2d 538 (1992).

3. The settlement for PG&E met the criteria for settlements under Rules 51 *et seq.* Rule 51.6 was satisfied by conducting an evidentiary hearing and the filing of briefs on the contested issues.

4. The settlements are reasonable in light of the whole record.

5. The settlements are in the public interest.

6. The costs incurred by Edison and SDG&E towards the decommissioning of SONGS Unit 1 were reasonable.

7. The costs incurred by PG&E towards the decommissioning of Humboldt Unit 3 were reasonable.

8. Under Rule 51.8, the adoption of the proposed settlements creates no precedent for subsequent triennial reviews of the nuclear decommissioning trust funds or the decommissioning activities of Edison, SDG&E, or PG&E.

9. The Settlements do not contravene or compromise any statutory provision or Commission decision, and are consistent with law.

10. It is reasonable to direct the parties to conduct and include detailed studies in subsequent triennial decommissioning review proceedings.

11. A.05-11-008 and A.05-11-009 should be closed.

FINAL ORDER

IT IS ORDERED that:

1. The attached settlement in Appendix B for Application (A.) 05-11-008 is adopted.

2. The attached settlement with updates in Appendix B for A.05-11-009 is adopted.

3. Southern California Edison Company (Edison) shall file a compliance advice letter with the Commission's Energy Division within 10 days of the effective date of this decision. It shall be served on the service list for this proceeding. The advice letter shall describe how Edison will implement the settlement as adopted in this decision, subject to Energy Division determining that the filing is in compliance with this order. Edison may consolidate the rate changes authorized in this decision with its Energy Resource Recovery Account forecast compliance filing in early 2007.

4. San Diego Gas & Electric Company (SDG&E) shall file a compliance advice letter with the Commission's Energy Division within 10 days of the effective date of this decision. It shall be served on the service list for this proceeding. The advice letter shall describe how SDG&E will implement the settlement as adopted in this decision and the tariffs will be effective on January 1, 2007, or the first day of the month following the effective date of this order, subject to Energy Division determining that the revised tariffs are in compliance with this order. SDG&E is authorized to apply $2.79 million of the overcollection in its Nuclear Decommissioning Adjustment Mechanism as a 12-month amortization to the nuclear decommissioning rate effective January 1, 2007, to offset the impact of the increase in the Nuclear Decommissioning revenue requirement in 2007.

5. Within 10 days of the effective date of this Decision, Pacific Gas and Electric Company (PG&E) shall file a separate compliance advice letter with the Commission's Energy Division, which shall include the revenue requirement described in the Settlement Agreement. 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 this proceeding. The compliance advice letter shall describe how PG&E will implement the settlement as adopted in this decision. In accordance with Item 6 of the Settlement Agreement, PG&E shall file a second compliance advice letter in the first quarter of 2007 to update the 2007-2009 revenue requirements that incorporate the December 31, 2006 nuclear decommissioning trust fund balances. The update will serve as the basis for the required IRS Schedule of Ruling Amounts for years 2007-2009. An adjustment to the Nuclear Decommissioning Adjustment Mechanism (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 letters.

6. Edison, SDG&E, and PG&E 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.

7. Edison, SDG&E, and PG&E 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 conservatively forecast the costs of low level radioactive waste storage.

8. Edison, SDG&E, and PG&E 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 conservatively establish an appropriate contingency factor for inclusion in the decommissioning revenue requirements.

9. A.05-11-008 and A.05-11-009 are closed.

This order is effective today.

Dated January 11, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
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Commissioners

APPENDIX A: SERVICE LIST

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(END OF APPENDIX A)

Decision 10-07-047 (July 29, 2010)

ALJ/MD2/hkr Date of Issuance 8/5/2010

Decision 10-07-047 July 29, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company in its 2009 Nuclear Decommissioning Cost Triennial Proceeding. (U39E)	Application 09-04-007 (Filed April 3, 2009)
Joint Application of Southern California Edison Company (U338E) and San Diego Gas & Electric Company (U902E) for the 2009 Nuclear Decommissioning Cost Triennial Proceeding to Set Contribution Levels for the Companies' Nuclear Decommissioning Trust Funds and Address Other Related Decommissioning Issues.	Application 09-04-009 (Filed April 3, 2009)

(See Appendix D for List of Appearances.)

DECISION ON PHASE 1 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

TABLE OF CONTENTS

DECISION ON PHASE 1 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

1. Summary

The purposes of the nuclear decommissioning cost triennial proceedings (NDCTP) are to set the annual revenue requirements for the decommissioning trusts for the nuclear powerplants owned by Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company, to verify the utilities are in compliance with prior decisions applicable to decommissioning, and to determine whether actual expenditures by the utilities for decommissioning activities are reasonable and prudent. (Decision 07-01-003.) These NDCTP proceedings were divided into two phases by an August 3, 2009 ruling which provided that issues relating to trust fund management would be considered in Phase 2.

This decision resolves all issues in Phase 1. It does not adopt the contested settlement proposed by the three utilities and The Utility Reform Network (Settling Parties). Although this is not an all-party settlement, the Settling Parties include the three applicants and The Utility Reform Network, the most active intervenor in these proceedings. The Commission's Division of Ratepayer Advocates and intervenor Scott Fielder opposed the Settlement on several grounds.

Specifically, we reject the proposed change to the reasonableness review process for decommissioning expenditures from Phases 2 and 3 of San Onofre Nuclear Generation Unit 1 and all phases of Humboldt Bay Powerplant 3 because we find the proposal is not in the public interest and is unreasonable in

light of the whole record. This provision alone is of sufficient importance to the Commission that the Settlement is rejected. Instead, the Commission examined the utilities' applications using the reasonableness standard, in light of the other Settlement provisions upon which there was broad, if not complete, agreement, and the evidentiary record developed through hearings.

We find that most of the changes proposed by the Settlement are reasonable including approval of the submitted decommissioning cost estimates and expenditures, and the revised rates of return assumptions and proposed annual trust fund contributions. We also agree with all parties that certain identified areas of inquiry would assist the Commission and ratepayers in future NDCTPs, and adopt the Settlement's plan for an independent panel of decommissioning experts who could examine certain decommissioning cost issues, most importantly to identify what drives differences in cost estimates and to develop common cost reporting methods that would provide better transparency and comparability. In this decision, we slightly modify the panel's tasks, establish a process timeline that incorporates Commission and party input, and clarify the panel's funding.

2. Requests

2.1. SCE and SDG&E

In a Joint Application filed on April 3, 2009, (A.) 09-04-009,[1] SCE and SDG&E request that the Commission:

1 On May 7, 2009, Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) filed an amendment to their joint application which consists of three corrections relating to SCE's requests in the application.

(1) find the $207.2 million (100% share, 2008$) cost of San Onofre Nuclear Generating Station (SONGS) Unit 1 decommissioning work completed between July 1, 2005 and December 31, 2008 is reasonable;

(2) find the updated $184.4 million (100% share, 2008$) SONGS Unit 1 decommissioning cost estimate for the Remaining Work is reasonable; and

(3) find the updated $3,658.8 million (100% share, 2008$) SONGS Units 2 & 3 decommissioning cost estimate is reasonable.

In addition, SCE requests the Commission:

(1) find the updated $708.7 million (SCE's share, 2007$) Palo Verde (PV) decommissioning cost estimate is reasonable; and

(2) authorize a revenue requirement of $66.4 million for contributions to its Nuclear Decommissioning Trust Funds for SONGS Units 2 & 3 and for Palo Verde Nuclear Generating Station Units 1, 2, & 3 through the Nuclear Decommissioning Cost Charge.

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

(1) Find the updated estimate of SDG&E's ratable share of the decommissioning costs for SONGS Units 2 & 3 of $731.8 million is reasonable;

(2) Authorize a revenue requirement for SDG&E's annual contribution to its Nuclear Decommissioning Trust Fund for SONGS Units 2 & 3 in the amount of $15.284 million, effective May 1, 2010. (SDG&E is not seeking to increase rates in this proceeding.) SDG&E proposes and requests approval to (a) omit any rate impacts from the increase in the nuclear decommissioning revenue requirement in 2010 and utilize the overcollection in its Nuclear Decommissioning Adjustment Mechanism (NDAM) balancing account, forecasted to be $2.336 million for the period ending December 31, 2009, to offset the revenue requirement increase in 2010 partially; and (b) address the resulting net balance in the NDAM balancing account as part of SDG&E's annual electric regulatory account

update advice filing filed in October of each year for rate effective January 1 of the following year.[2] In addition, SDG&E intends to utilize overcollections in other balancing accounts (e.g., the Transition Cost Balancing Account) or offset any nuclear-decommissioning rate change with revenues from other regulatory accounts;

(3) Find that SDG&E may reasonably rely upon SCE, as the majority owner of and exclusive operating and decommissioning agent for SONGS Units 1, 2, and 3, to make those reasonable efforts to retain and utilize sufficient qualified and experienced personnel to pursue any decommissioning-related activities for the nuclear generation facilities under their control effectively, safely, and efficiently, as required by the Commission in Decision (D.) 07-01-003, subject to the proviso that SDG&E shall review and provide such advice and consent to SCE as may be necessary and appropriate to the interests of SDG&E as a minority owner and/or on behalf of the interests of SDG&E's retail electric customers;

(4) Find that SDG&E may reasonably rely upon SCE, as the majority owner of and exclusive operating and decommissioning agent for SONGS Units 1, 2, and 3, to make those reasonable efforts to forecast the costs of low-level radioactive waste storage conservatively, as required by the Commission in D.07-01-003, subject to the proviso that SDG&E shall review and provide such advice and consent to SCE as may be necessary and appropriate to the interests of SDG&E as a minority owner and/or on behalf of the interests of SDG&E's retail electric customers;

(5) Find that SDG&E may reasonably rely upon SCE, as the majority owner of and exclusive operating and decommissioning agent for SONGS Units 1, 2, and 3, to make all reasonable efforts to

[2] If the Commission authorizes an increase of annual contributions to SDG&E's nuclear decommissioning trusts but does not permit deferral of rate changes to beyond 2010, SDG&E seeks an allowance for franchise fees and uncollectibles to be added to the annual revenue requirement approved for and billed in 2010.

establish an appropriate contingency factor for inclusion in the decommissioning revenue requirements, as required by the Commission in D.07-01-003, subject to the proviso that SDG&E shall review and provide such advice and consent to SCE as may be necessary and appropriate to the interests of SDG&E as a minority owner and/or on behalf of the interests of SDG&E's retail electric customers; and

(6) Find that the transfer of funds from the non-qualified trust fund for the decommissioning of SONGS Unit 1 to the qualified trust funds for the decommissioning of SONGS Units 2 & 3 should not be required at the present time due to:

(a) the uncertainties associated with determining the actual and final reasonable costs for the decommissioning activities related to SONGS Unit 1;

(b) the uncertainties associated with determining whether the actual return on investments will be sufficient to increase total fund assets to an amount no less than the actual and final reasonable costs for the decommissioning activities related to SONGS Unit 1; and

(c) the absence of any exigencies or circumstances that would either require the transfer of funds from the non-qualified and/or qualified trust funds for the decommissioning of SONGS Unit 1 to the qualified trust funds for the decommissioning of SONGS Units 2 & 3 at this time or that would preclude such a transfer at a more appropriate and later date when the aforementioned uncertainties would be more largely and likely resolved.

2.2. PG&E

In a separate application, A.09-04-007, Pacific Gas and Electric Company (PG&E) requests the Commission to authorize the collection, through Commission-jurisdictional electric rates, of the following amounts in 2010 through 2012 for decommissioning of Diablo Canyon and Humboldt Unit 3:

(1) $23.329 million for the Diablo Canyon (DC) Nuclear Decommissioning Trusts for Units 1 and 2, respectively (the 2009 revenue requirement is $1.297 million); and

(2) $16.982 million for the Humboldt Unit 3 Nuclear Decommissioning Trust (the 2009 revenue requirement is $10.995 million);

Additionally, PG&E requests the Commission to:

(3) authorize revenue requirements to cover the costs of operating and maintaining (O&M) the Humboldt Unit 3 site in a safe condition (SAFSTOR). Specifically, PG&E is requesting SAFSTOR revenue requirement of $9.218 million in 2009, a decrease from the authorized amounts of $13.405 million for 2009. PG&E is also requesting attrition for SAFSTOR expenses in 2011 and 2012; and

(4) find that PG&E's activities with respect to licensing, design, fabrication, and construction of the Independent Spent Fuel Storage Installation (ISFSI) and associated activities were reasonable and prudent.

3. Procedural History

Notice of these two applications appeared in the Commission's Daily Calendar on April 8, 2009. The Commission preliminarily categorized them as ratesetting in Resolution ALJ 176-3232, dated April 16, 2009. The Division of Ratepayer Advocates (DRA) protested both applications. The Utility Reform Network (TURN) filed a protest to SCE/SDG&E's application and a response to PG&E's application. The Merced Irrigation District and Modesto Irrigation District filed a joint response to PG&E's application, but did not otherwise participate.

The proceedings were consolidated in the Scoping Memo and Ruling issued June 15, 2009 and expanded to include an examination of the management of the decommissioning trust funds maintained by each utility. The utilities were also ordered to serve Supplemental Testimony to 1) describe their compliance with certain requirements from the prior Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) (Ordering Paragraphs 6-8 of D.07-01-003), and 2) provide information about investment fund managers hired by the nuclear decommissioning trust funds, performance of the investment funds, management costs, and efforts to develop emerging investment fund managers. On July 30, 2009, the Commission adopted Resolution E-4258 which referred to these proceedings consideration of a modified procedure sought by PG&E[3] for reviewing and determining the reasonableness of its expenditures for decommissioning the Humboldt Bay Powerplant 3 (HB3). A subsequent ruling by Administrative Law Judge Darling (ALJ) clarified the expanded scope of the proceedings and divided them into two phases. Phase 1 would consider the usual issues for an NDCTP and include the issue of whether to modify the Commission's reasonableness review of decommissioning expenditures. The utilities were directed to file a brief discussing the reasonableness review issue and other parties were permitted to file reply briefs. The issues regarding trust fund management were deferred to Phase 2.

The utilities filed a joint brief in which they presented the reasonableness review proposal as applicable to all phases of decommissioning for SONGS Units 1, 2, and 3 and HB3. Customer-intervenor Scott Fielder (Fielder) filed a brief in opposition to any changes to the current review process. All parties

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[3] On March 27, 2009, PG&E filed Advice Letter 3444-E in which it provided notice of its intent to begin decommissioning of HB3, requested general authorization for interim trust fund disbursements, and sought approval of a procedure whereby its decommissioning costs would be presumed reasonable if within the scope and amount approved in the 2009 NDCTP cost estimates for HB3.

served timely rebuttal and other supplemental testimony as allowed or required by the ALJ. Five days of evidentiary hearings were held from October 13 through October 19, 2009, including a portion reserved for oral argument on the reasonableness review issue which was attended by assigned Commissioner Timothy Alan Simon. At the conclusion of the evidentiary hearings, the underlying testimony of witnesses in this phase of the proceedings was received into evidence without objection. A list of all Exhibits admitted into the record is attached hereto as Appendix A.

Upon notice of a pending Settlement Agreement among some or all of the parties, the ALJ extended the deadlines for filing post-hearing briefs. On December 18, 2009, the utilities and TURN filed a Motion for Approval of Settlement Agreement which purported to resolve all issues in Phase 1. Both DRA and Fielder filed Opposition to the Motion. A hearing on the Motion and terms of the proposed Settlement Agreement was held on April 5, 2010. The Settling Parties filed an opening post-hearing brief on April 16, 2010 and non-settling parties filed reply briefs on April 26, 2010.

Accordingly, the basis for adjudicating issues in this phase of the proceedings consists of (1) the evidence developed through written testimony and oral cross-examination on the underlying merits of issues in dispute, (2) the Settlement Agreement which represents a negotiated compromise of certain parties and the written comments filed in response to this agreement, and (3) the evidence developed through testimony and oral cross-examination at the hearing on Settlement and post-hearing written briefs.

4. Standard of Review

Pursuant to Rule 12.1(d) of the Commission's Rules of Practice and Procedure (Rules), the Commission's standard of review for both contested and uncontested settlements is whether the settlement taken as a whole is reasonable in light of the whole record, consistent with the law, and in the public interest. Rule 12.4 provides that the Commission may reject a proposed settlement whenever it determines the settlement is not in the public interest.

The applicants alone bear the burden of proof to show that the rates they request are just and reasonable and the related ratemaking mechanisms are fair.[4] Thus, if the settlement is rejected, then the reasonableness standard applies to the issues in the proceedings.

For the purposes of these proceedings and as used in the scope set forth above, we define reasonableness for decommissioning expenditures consistent with Commission findings, i.e., that the reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made.[5] However, with respect to Phase 1 SONGS Unit 1 decommissioning work, the Commission in D.99-06-007 adopted a ratemaking settlement that included a presumption that the utilities' expenses are reasonable in performing Phase 1 SONGS Unit 1 decommissioning work if the scope of the work completed and the most recently approved SONGS Unit 1 decommissioning cost estimate bound the costs incurred.[6]

We consider the applications and proposed Settlement based on these standards.

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[4] D.07-01-003 at 7.

[5] See, e.g., D.02-08-064 at 5-8.

[6] 86 CPUC2d 604, 620 (Settlement § 4.2.2.2c) (1999).

5. Settlement Agreement

A copy of the proposed Settlement Agreement is attached hereto as Appendix B. The key terms of the Settlement Agreement are as follows:

- SCE and SDG&E's decommissioning costs for SONGS Unit 1 (Phase 1) for the period July 1, 2005 through December 31, 2008 are reasonable.
- SCE and SDG&E's decommissioning cost estimates for SONGS Unit 1 (Phases 2 and 3) and SONGS Units 2 and 3; SCE's decommissioning cost estimates for Palo Verde Units 1, 2, and 3; and PG&E's decommissioning cost estimates for Diablo Canyon Units 1 and 2 and HB3 are reasonable for purposes of settling the authorized revenue requirement in this NDCTP and for future review of SONGS Unit 1 (Phase 2) and HB3 decommissioning expenditures in the next NDCTP application.
- Trust fund contributions for units owned by SCE or SDG&E would be based, among other things, on the following assumptions:
  - 8.75% pre-tax equity returns.
  - 4.2% post tax debt returns.
  - 6.93% burial escalation rate.
- Trust fund contributions for units owned by SCE and SDG&E would be based on the December 31, 2009 trust fund balances.
- PG&E funding for Diablo Canyon would be established as a fixed amount at $9 million per year, commencing January 1, 2010, with rate of return and fixed income assumptions to be adjusted to reach this funding requirement.
- HB3 funding would be generally determined in accordance with PG&E's application, based on updated after-tax fund balances as of December 31, 2009, reflecting unrealized capital losses.
- PG&E's completed activities and decommissioning expenditures at Humboldt as set forth in its application were reasonable in amount and prudently incurred.

- As required by Ordering Paragraph 6 of D.07-01-003, PG&E, SCE, and SDG&E have demonstrated that they have made all reasonable efforts to retain and utilize sufficiently qualified and experienced personnel to effectively, safely, and efficiently pursue any decommissioning activities at the Humboldt, Diablo Canyon, SONGS, and Palo Verde facilities.
- PG&E's request for SAFSTOR O&M expense plus attrition as presented in its application is reasonable.
- An independent panel will be created to review certain decommissioning-related issues and prepare a report that the Utilities will address in their cost estimates for the next NDCTP. Among other things, the independent panel will:
    - Identify, compare, and explain the key cost and financial assumptions driving differences in the cost estimates.
    - Identify, compare, and explain similarities and differences in decommissioning costs, challenges, and approaches for California nuclear units and plants of similar design and configuration in other states.
    - Identify and explain cost and financial assumptions that could be applied on a common basis to the estimates for Diablo Canyon, SONGS, and Palo Verde sites.
    - Identify and suggest steps that could be taken to minimize decommissioning costs in the future.
    - Evaluate whether emerging radiological contamination issues could increase decommissioning costs.
    - Suggest a common format for preparation of decommissioning cost estimates that would permit greater transparency and comparability.
- In the next NDCTP application, the applicants will provide contribution estimates that would assume successful completion of license renewal, for informational purposes only.

- In the next NDCTP application, the applicants will provide contribution estimates that assume some equity investment by the trust funds after unit shutdown.
- The Settling Parties request that the Commission and other state agencies formally ask the United States Department of the Navy (i.e., the lessor of the SONGS site) to clarify the site restoration and remediation standards that would be required to terminate the SONGS site lease contract. Consistent with this effort, SCE and SDG&E agree to propose a partial termination of the Nuclear Regulatory Commission (NRC) license(s) for the SONGS site that would exclude the ISFSI.
- The reasonableness review method adopted in D.99-06-007 for decommissioning activities and expenditures from Phase 1 at SONGS Unit 1 would be continued for all other phases at SONGS Unit 1 and applied to all post-2008 decommissioning activities and expenditures for HB3.

6. Parties' Final Positions on Contested Issues

6.1. DRA

With the exception of PG&E's burial escalation rate, DRA generally supports the cost estimates provided by the utilities and has not disputed any of the claimed expenditures. However, DRA opposes the Settlement provisions setting PG&E's contribution for the DC units, the extension of the modified reasonableness review to Phases 2 and 3 of SONGS Unit 1, and some aspects of the proposed independent panel. DRA contends the Settlement, as a whole, has no public benefit for consumers, violates the law, and violates the Commission's purpose in creating the NDCTP.

Calling it the "most contentious and inappropriate" term of Settlement, DRA argues there is no support in the record for the negotiated $9 million per year annual contribution for the DC trust funds. Using the trust fund balances as of December 31, 2009 and SCE's proposed Low Level Radioactive Waste (LLRW) burial escalation rate, DRA calculates that a $1.8 million annual contribution is enough to fully fund the trusts. Even if PG&E's higher burial escalation rate is used, the record only supports a $5 million annual contribution. Because there is no testimony in the record in support of a $9 million annual contribution, DRA also concludes the Settlement improperly proposed a new issue.

As for modification of the reasonableness review process, DRA draws a distinction between remaining phases for SONGS Unit 1 and the complete decommissioning of HB3. DRA supports the creation of a reasonableness presumption for all phases of HB3 where PG&E says it will finish decommissioning by the end of the decade. In contrast, DRA characterizes the previously approved SONGS Unit 1 process as a "one-time exemption for an imminent decommissioning"[7] phase. DRA opposes extension of the modified procedure to Phases 2 and 3 of the SONGS Unit 1 decommissioning because it views these activities as far in the future and the estimated costs as too speculative. DRA contends the proposal would undermine Commission authority to review such expenditures on behalf of ratepayers and would violate past decisions and policies. Phases 2 and 3 are not projected to be completed until 2053. Over the years, DRA emphasizes, the Commission has repeatedly acknowledged that forecasts of nuclear decommissioning costs into the future are very speculative and subject to substantial error. Because Pub. Util. Code § 8322(3) states ratepayers should only be charged for costs reasonably and prudently incurred, DRA concludes the Commission cannot legally make such a determination based solely on advance estimates.

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[7] Comments of the Division of Ratepayer Advocates Opposing the Settlement (DRA Comments) at 17-18.

Furthermore, DRA argues the utilities have not offered adequate justification for the proposed change and it is unreasonable to shift the burden to consumer advocates who are at a time and expense disadvantage in trying to examine decommissioning costs and actions after-the-fact. According to DRA, this shift conflicts with the Legislature's intent that the Commission provide for "periodic review procedures that create maximum incentives for accurate cost estimations, and provide for decommissioning cost controls."[8] In support, DRA cites *TURN v. Public Utilities Commission*,[9] in which TURN challenged the reasonableness of an approved rate increase granted to PG&E for decommissioning. According to DRA, the Supreme Court rejected the challenge because the Commission would ultimately conduct an after-the-fact review to determine reasonableness and whether to refund any over-collections.[10]

DRA agrees that the goals of the proposed independent panel would be helpful to the Commission. However, DRA is concerned about the lack of details and procedural guidance in the Settlement Agreement as well as composition of the panel. DRA thinks using the same consultants employed by the utilities and TURN in current and prior NDCTPs may not provide "independence" because they will rely on their former and future employers for information and data. Instead, DRA suggests the Commission, rather than the utilities, should establish any such panel and include representation by the Commission and/or DRA.

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[8] Pub. Util. Code § 8323.

[9] 44 Cal. 3d 870 (1988).

[10] 44 Cal. 3d at 878.

6.2. Fielder

Fielder opposes the Settlement on the grounds that 1) the proposed independent panel will lack independence and transparency, 2) the 25% contingency factor is too low, and 3) the proposed rebuttable presumption of reasonableness for decommissioning expenditures lacks justification and violates the law.

He argues the proposed independent panel, formed to study similarities and differences in decommissioning cost studies, would not be "independent" because it only includes the cost experts from these proceedings and does not include either him or DRA. He describes the panel's prospective work as "secret" and subversive of the NDCTP. He also objects to the exclusion of HB3 costs from those the panel would examine.

Fielder has opposed the application of a 25% contingency factor to HB3 throughout the proceedings and argues again that it fails to address financial risks, regulatory risks, or changes in scope.[11] However, in his comments on the Proposed Decision, Fielder claims he agrees with a 25% contingency factor for HB3.

Lastly, Fielder contends the change to the reasonableness review is without policy justification or legal authority. He argues that the proposed change violates the California Constitution and Pub. Util. Code §§ 8325(c) and 8328 of the California Nuclear Facilities Decommissioning Act of 1985 (NFDA) which require the Commission to limit recovery of decommissioning costs to those reasonable in amount and prudently incurred. Instead, Fielder argues, the

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[11] See, e.g., Fielder's Notice of Intent to Claim Compensation at 5; Fielder Exh. 1 at 7-9; Fielder Exh. 2 at 4.

proposal merges the cost estimate phase with the after-the-fact review, resulting in no actual burden of proof on the utility so long as the last cost estimate was not exceeded. Minimizing cost would become the only barometer of whether costs were reasonable in amount or prudently incurred. Moreover, Fielder states that both PG&E and SCE have decided to act as their own general contractor for decommissioning which poses a potential conflict-of-interest that calls for a higher, not lower, level of review.

According to Fielder, the proposed change to the reasonableness review violates long-settled Commission policy that utilities have the burden of proving the reasonableness of rate increases. In addition to failing to demonstrate any justification for the change, Fielder charges the proposal ignores strong public policy in favor of keeping the burden of proof on the utilities. Not only has this been the law and the policy of the Commission, it is significant to ratepayers because DRA has limited staff to fully investigate utility decommissioning expenses and decision-making. Thus, Fielder concludes, altering the review process at this time would expose ratepayers to less than full review of the utilities' future decommissioning activities and expenditures.

6.3. The Settling Parties

SCE, SDG&E, PG&E, and TURN, the Settling Parties, assert the following:

A fair reading of the evidentiary record from these proceedings demonstrates the contentiousness of the issues raised and settled by the Settling Parties. Notwithstanding substantial disagreement, the parties were able to find enough common ground to craft a comprehensive settlement which meets the standards for review and approval of settlements. Therefore, sufficient give-and-take is established and the Settlement should be adopted by the Commission.

The Settlement represents compromise of a significant dispute between SCE/SDG&E and TURN over estimation methodologies and results, both of which represented considerable litigation risk to both sides. It also resolved a major dispute between PG&E and TURN over the funding of the DC trust funds which included a number of issues (e.g., rates of return, contingency factors, labor termination costs, etc.) that posed mutual litigation risks. According to the Settling Parties, DRA's charges that no give-and-take occurred and no evidentiary basis exists for compromising the DC contribution are wrong.

Settling Parties believe the $9 million annual contribution for DC trust funds is a reasonable outcome given PG&E's omitted labor termination costs and potential to claim a higher contingency factor applicable to the DC cost estimate. PG&E's witness Loren Sharp testified that PG&E's cost estimate did not include, but should have included, labor termination costs, and explained how he developed the $135 million estimate.[12] He also stated the 25% contingency factor did not cover non-engineering risks and that PG&E was "at risk" for additional costs.[13] According to the Settling Parties, if the DC trusts are updated and the cost estimate reflects 35% contingency and the labor termination costs, it would result in a $29 million annual contribution.[14]

The Settling Parties state that there is evidence in the record to show TURN also considered the likelihood of success of its proposals to assume higher rates of return on trust fund investments that would have lowered PG&E's

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[12] Reporter's Transcript at 867.

[13] Reporter's Transcript at 868-69.

[14] Exhibit PG&E-20.

funding requirements. When PG&E's persuasive arguments to raise its DC cost estimates are balanced with TURN's counter arguments, the Settling Parties believe the provision for the $9 million annual funding is a reasonable outcome, supported by the record, and is in the public interest.

Additionally, the Settling Parties state none of the issues raised in connection with this matter are new. They were raised during the proceedings and the evidence supports PG&E's arguments for a higher contingency factor and labor costs for DC. The Settling Parties believe DRA errs when it asserts that past Commission decisions prevent a utility from adjusting projections and assumptions after hearing because the Commission must balance its obligation to keep rates low with the objectives of assuring adequate funding and that the customers who use the generated nuclear power are the ones who pay the decommissioning expenses.

The Settling Parties maintain the proposed reasonableness review procedures fully comport with the Commission's responsibility to set just and reasonable rates. According to the Settling Parties, Fielder's opposition is predicated on the fallacious argument that extending the existing procedure violates Article XII § 2[15] of the California Constitution. Despite Fielder's mischaracterization of the in-place SONGS Unit 1 reasonableness review standard as a "departure from the traditional standard of review," the process is not novel. The SONGS Unit 1 process was adopted by the Commission in D.99-06-007 and has been reapproved in each triennial since then without objection.

[15] Article XII § 2 provides that the Commission, subject to statute and due process, may establish its own procedures.

The Settling Parties point out that DRA joined in the original settlement that established the SONGS Unit 1 review procedure and at the time found it a suitable alternative. Further, there are sound public policy reasons to adopt it. Foremost, the utilities will retain the burden of proof to show their rates are just and reasonable, and only reasonable and prudent costs are recovered. Opposing parties have ignored the details of the process in place for SONGS Unit 1 to arrive at their criticisms. Instead, the demonstration of reasonableness is made in two parts: 1) utilities must prove that the cost estimates provided in NDCTPs are reasonable, and 2) the utilities must submit an accounting of the recorded expenditures in the next NDCTP supported by testimony that compares expenditures to cost estimates. Where the expenditures materially vary, the utilities have the burden to demonstrate through additional evidence the expenditures are reasonable.

The Settling Parties believe that if the settlement is adopted, the Commission would continue to make the determination as to whether the decommissioning expenditures were prudently incurred and the utilities would not in any way evade their duty to justify, through competent evidence, that their cost estimates are reasonable and their expenditures are reasonable and prudently incurred. If any party made a credible case that a utility's expenditures were unreasonable or imprudently incurred, the utilities could not rely on the rebuttable presumption to overcome that party's showing.

Furthermore, according to the Settling Parties, the NFDA does not specify a particular process or standard for the Commission to apply in reviewing decommissioning expenditures for reasonableness. In fact, the NFDA only provides for reviewing actual costs for reasonableness if the trust funds are insufficient for payment.[16] Thus, the Legislature considered the initial review of the cost estimates the best opportunity for cost controls and required it to occur "periodically."[17] Contrary to the claims of Fielder and DRA, the Settling Parties state that the Settlement Agreement would not change the triennial filings of the utilities.

In addition, according to the Settling Parties, the proposed independent panel, which is intended to perform a one-time analysis of the cost estimates, procedures, and assumptions used in the NDCTPs, will enable the parties and the Commission to better evaluate the cost estimates. The composition of the panel is appropriate because these are decommissioning cost experts who will not be an advocate for any party in their roles on the panel.

The Settling Parties also state that to the extent that DRA was concerned about a lack of procedural detail about how the panel would function, the Settlement Agreement provides a reasonable framework for the parties to understand the purpose, responsibilities, and goals of the panel.

Additionally, the Opening Post-hearing Brief filed by the Settling Parties provides more information about the parties' agreed upon process and funding for the panel. Specifically, in the course of performing its review and preparing a report, the panel would provide opportunities for all parties and Commission staff to be apprised of progress, have access to documents used, and to comment

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[16] § 8328.

[17] § 8327.

on the direction and scope of work. The panel would produce a report on the specific issues by November 1, 2010.

7. Discussion of Contested Issues

There were a large number of contested issues in these proceedings. During the course of these proceedings, the parties have moved from their initial positions on numerous issues. A summary of their pre-Settlement positions is attached hereto as Appendix C.

The Settlement Agreement is sponsored by parties representing a range of interests but is not supported by all parties. Certain provisions are opposed by DRA and Fielder who represent ratepayer interests. We appreciate the fact that the Settlement reflects a range of divergent interests, including those of the utilities and of residential customers. In addition, we have also reviewed and considered the objections of those parties that did not join in the Settlement. As discussed below in detail, we find merit in some of the objections raised by these parties, and we reject the proposed adoption of a rebuttable presumption of reasonableness for decommissioning costs for activities, other than Phase 1 of SONGS Unit 1, as not in the public interest nor reasonable in light of the whole record. (See Section 7.7 below.) Therefore, we reject the Settlement as a whole and now consider whether there is a reasonable basis for approving the proposed cost estimates, past expenditures, proposed trust fund contributions, and other policy matters based on the final positions of the parties after five days of full evidentiary hearings, settlement negotiations, an evidentiary hearing on the proposed Settlement, and post-hearing briefs filed by the parties.

7.1. Compliance With D.07-01-003

During the 2005 NDCTP, which was resolved by adoption of a settlement, the Commission ordered the utilities to serve testimony in the 2009 NDCTP in three areas: 1) the use of qualified and experienced personnel, 2) a conservative forecast of costs for LLRW storage, and 3) a conservative and appropriate contingency factor for inclusion in each utility's decommissioning revenue requirements.

Each utility provided information about its own process for assuring that only qualified and experienced personnel are used for decommissioning activities planned or occurring at SONGS Unit 1 and HB3.[18] The utilities also jointly retained a consultant to perform an analysis of representative LLRW disposal rates available throughout the industry and used the identified base rates to develop a projected rate for use in the 2009 NDCTP. The utilities used the results and the evidence supported that the forecasts were conservative.

Lastly, PG&E developed and submitted a "Technical Position Paper for Establishing an Appropriate Contingency Factor for Inclusion in the Decommissioning Revenue Requirements" which included a review of available literature and reports, use of a contingency factor by other related industries, and recommended cost engineering practices from established professional organizations. The paper concluded that a 25% contingency factor for all nuclear decommissioning costs should be applied. SCE agreed based on its own independent research that the 25% contingency factor was conservative and appropriate. Both the original applications and the settlement proposal in these proceedings apply a 25% contingency factor to the cost estimates for all nuclear units.[19] Fielder objected to 25% factor as inadequate because it excluded financial

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[18] Exhibit SCE-1 at 11; PG&E Supplemental Testimony at 3-1 through 3-3.

[19] As discussed in more detail below, there is inconsistency between the utilities as to whether this factor covers only engineering contingencies or other unknown risks.

and regulatory risk and changes in scope. However, there was evidence that to the extent such risks were not included in a utility's contingency, they were otherwise accounted for in the cost estimates.

We find that SCE, SDG&E, and PG&E are in compliance with prior decisions applicable to decommissioning, including the Ordering Paragraphs 6, 7, and 8 of D.07-01-003 described above. We confirm that SDG&E may reasonably rely upon SCE, the majority owner of and exclusive operating and decommissioning agent for SONGS Units 1, 2, and 3 to make reasonable efforts to comply with the Commission's directives in D.07-01-003.

7.2. Approval of Decommissioning Cost Estimates

The utility cost estimates contain a degree of speculation by nature, partly due to persistent uncertainties about the key component of future storage and disposal costs for radioactive waste, and partly because detailed engineering studies are not completed until decommissioning is imminent. Over time, the Commission has seen substantial increases to the cost estimates brought forward by the utilities for review and approval. That trend continued in these proceedings and led to a high level of scrutiny by parties and the ALJ during the evidentiary hearings.

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 supported by the evidence. We adopt these cost estimates subject to a few changes in assumptions as discussed below reflecting agreed terms in the proposed Settlement, and which are bound by the evidentiary record.

7.2.1. SONGS Units 1, 2, and 3

The remaining work scope for SONGS Unit 1 consists of Phase 2 which will end when all Spent Nuclear Fuel (SNF) is removed from the site and Phase 3 which is mostly dismantling and disposing of the ISFSI. Phase 3 is scheduled to occur concurrently with Phase 3 for SONGS Units 2 and 3 and projected to be completed in 2053. The estimated costs to complete decommissioning of SONGS Units 1, 2, and 3 were developed by ABZ, Inc. (ABZ), a recognized expert in nuclear decommissioning costs, using data provided by SCE based on its experience with SONGS Unit 1 and tested against ABZ's database of decommissioning costs at other nuclear sites.[20] SDG&E conducted its own independent review of the ABZ cost study.

The SONGS Units 2 and 3 cost estimates increased from the 2005 NDCTP by $124.5 million (100% share, 2008$) due to assumed higher energy costs and staff and separation costs arising from NRC-mandated security actions, additional five-year delay to 2020 before SNF is removed, localized labor rates, related staff separation costs, and the application of a 25% contingency factor to the staffing costs.[21]

TURN initially viewed the estimates as excessive, but modified its position during the evidentiary hearings.[22] We also find reasonable the use of the LLRW

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[20] The cost studies intended to account for recent changes in technology, regulation, and economics and also account for the unique features of each facility.

[21] The SONGS units sit on land owned by the United States Department of the Navy and there are significant uncertainties about the required standards for final site restoration and site lease termination. Therefore, SCE and SDG&E have made very conservative assumptions about the amount of contamination they must remove.

[22] Reporter's Transcript at 565.

burial rates from the joint utility study and application of a 6.93% burial escalation rate based on historical rates.[23]

Based on the foregoing, we find that the cost estimates for SONGS Units 1, 2, and 3 are reasonable.

7.2.2. Palo Verde Units 1, 2, and 3

Arizona Power Service (APS), the operating agent for the Palo Verde units, retained TLG Services, Inc. (TLG) to prepare a decommissioning cost study. TLG, also a recognized expert in the field of decommissioning costs, used drawings and inventory documents to estimate waste volumes and make other assumptions in the cost study. SCE concluded that some assumptions made by TLG were inconsistent with SCE's experience and risk tolerance and, therefore, SCE made substantial adjustments to the TLG estimate and then applied a 25% contingency factor to all costs.[24]

The resulting estimate of $708.7 million (2007$) for SCE's share of all three units is about 7% below the estimate adopted in the 2005 NDCTP primarily due to significantly reduced LLRW burial costs, even though additional waste volume was projected.

Based on the foregoing, we find that the cost estimates for SCE's share of decommissioning the Palo Verde units are reasonable.

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[23] After a new LLRW burial site becomes available to California nuclear generation facilities, we expect the utilities to review the escalation rates using then current data.

[24] For example, APS assumed that it would incur no costs for disposal of non-contaminated materials or final clean-up following United States Department of Energy disposal of SNF.

7.2.3. Humboldt Bay Powerplant 3

PG&E has begun preparatory decommissioning activities at HB3 and intends to commence decommissioning of the plant in 2010 and act as its own general contractor. PG&E retained TLG to prepare a detailed cost estimate which assumed a delay in beginning SNF disposal until 2020 and applied the LLRW burial costs from the LLRW cost study, a 7.5% burial escalation rate, an employee labor escalation rate of 3.75% based on its union contracts, and a 25% contingency rate[25] to all costs. The estimate of $499.8 million (2008$) excludes $385,520 that has been disallowed by the Commission, but includes $82.3 million in costs incurred or projected to be incurred in 2009. The primary reasons for increases to the estimate from 2005 are increased staffing levels, revised or added unit cost factors for some activities, and increased waste volumes driven in part by site-specific challenges.

DRA generally accepted the cost estimate, but thought SCE's lower burial escalation rate of 6.93% should be used. PG&E used the higher figure based on its use in prior NDCTPs, the unreliability of having few data points in the LLRW study, and uncertainties about future disposal rates. PG&E's explanation of its differences on these items was reasonable for purposes of these proceedings. In the Settlement, the parties agreed to a modified labor rate which reflected PG&E's union contracts through expiration in 2011. This is also reasonable.

Fielder argued that a composite figure be used for LLRW disposal rates. However, there is no evidence that this approach is superior to the graded rates developed in the LLRW study and may be contrary to the Commission's

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[25] D.07-01-003 adopted a 25% contingency rate for HB3 in the 2005 NDCTP.

direction in D.07-01-003. Additionally, Fielder's requested 35% contingency factor seems excessive and lacks evidentiary support. PG&E's witness Sharp explained that the 25% contingency factor was not intended to include changes in scope or other conditions which should be factored into the underlying cost estimate prior to application of the contingency rate.[26]

Based on the foregoing, we find that the cost estimate for HB3 is reasonable. In addition, we find that PG&E's uncontested forecast for 2010 O&M expenses associated with maintaining HB3 in SAFSTOR, including attrition through 2012, is reasonable.

7.2.4. Diablo Canyon Units 1 and 2

PG&E retained TLG to prepare cost estimates for the DC units under two decommissioning scenarios which included the same labor and LLRW burial rate assumptions and 25% contingency factor described above for the HB3 cost study. Under the more likely "DECON" method, which provides for prompt removal and dismantling of the facility, the total estimated cost for both units is $1,828.35 million (2008$). Consistent with the current operating license, the 2009 cost study also reflects shutdown dates for Units 1 and 2 of November 2024 and August 2025, respectively.

No significant objections were made to the cost estimates except that DRA continues to argue that PG&E should use SCE's LLRW burial escalation rate. The difference in cost would be about $1.8 million[27] but we find that PG&E reasonably justified its use of the 7.5% rate. However, we adopt the proposed

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[26] Reporter's Transcript at 201-203.

[27] Reporter's Transcript at 849.

modification of PG&E's labor escalation rates contained in the Settlement, which fall within the bounds of the evidentiary record: 3.75% for 2009-2010, 4.0% in 2011, and use of SCE's 3.14% after 2011.

Based on the foregoing, we find that the cost estimates for DC Units 1 and 2 are reasonable, as adjusted.

7.3. Approval of Decommissioning Expenses

In the first NDCTP, the Commission adopted a settlement that authorized the commencement of decommissioning at SONGS Unit 1 and created a presumption of reasonableness for its decommissioning expenditures if kept within prior estimates. D.99-06-007 provides:

> If the scope of SONGS 1 (Phase 1) Decommissioning Work completed and costs incurred to date are bounded by the most recently approved SONGS 1 Decommissioning Cost Estimate, the Utilities' conduct will be presumed reasonable. Any entity claiming the Utilities acted unreasonably would, therefore, bear the burden of proving the Utilities acted unreasonably. The utilities will be responsible for proving that material variances from the most recently approved SONGS 1 Decommissioning Cost estimate are reasonable.[28]

To be entitled to a presumption of reasonableness here, SCE is required to provide a comparison of the 2004 estimated Phase 1 costs at SONGS Unit 1 to the actual costs for the work completed between July 1, 2005 and December 31, 2008. SCE incurred a net cost of $207.2 million (2008$) for the completed work compared to the $221.3 million (2008$) estimated cost approved in the 2005

[28] 86 CPUC2d 604, 620 (Attachment A Settlement Agreement § 4.2.2.2(c)).

NDCTP.[29] Actual costs were lower in nearly all categories. No party has contended the expenditures were not reasonable or prudent and SCE provided uncontested evidence the work was performed by qualified and experienced personnel. As a result, based on the settlement agreement adopted in D.99-06-007, SCE's actions are presumed reasonable and we find no evidence to suggest they were either unreasonable or imprudent.

PG&E is subject to the general reasonableness review rather than the presumption. The company provided a comparison of approved cost estimates and actual expenditures in connection with preparatory decommissioning activities at HB3. PG&E incurred a net cost of $63.4 million (2008$) for the work scope that was completed compared to an estimated cost identified in the 2005 NDCTP of $58.6 million (2008$). The biggest excess occurred in the primary category of "Licensing, Design, Fabrication, and Construction of ISFSI" due to new NRC requirements and both design and contamination issues related to the confined space. This expense was partially offset by lower than expected costs for shipment and burial of certain waste. PG&E provided uncontested evidence the work was performed by qualified and experienced personnel.

Based on the foregoing, we find the decommissioning expenses claimed by SCE and PG&E are reasonable and prudently incurred.

7.4. Rates of Return and Trust Fund Contributions

The Commission's adopted rates of return should capture a reasonably conservative growth trend over the life of the trust funds to match the estimated decommissioning costs. The recent economic downturn resulted in lower than

[29] Exhibit SCE-1 at 14.

expected returns in the trust funds during 2007 and 2008, initially prompting requests for significant contributions to some funds. 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. Inconsistent assumptions about the trust fund portfolios and management contributed to disparate results. As the proceedings progressed, the trust funds recovered some of their lost value and trust fund balances as of December 31, 2009 will be applied to calculate approved contributions.

7.4.1. Equity Rates of Return

SCE initially applied an 8.06% pre-tax return on equity, SDG&E applied 8.13%, PG&E used 8.5%, and TURN proposed 10.05% for all three utilities, each estimate based on nationally recognized indices.[30] TURN's recommendation was significantly different because it limited the forecast of equity returns to the 14-year period in which SCE and SDG&E funds were anticipated to hold equities, i.e., pre-decommissioning of SONGS Units 2 and 3. Thus, the 10.05% reflects the shorter-term forecast of higher returns for market recovery between 2009 to 2022, while the longer-term forecast out to 2038 is preferred by the utilities to smooth out a reasonable "average" return.

The utilities argued it was neither reasonable nor conservative to focus on shorter-term projections. They also proposed lower equity turnover rates than adopted in 2005 which seems reasonable given current market volatility.

[30] The forecasted rates of return are adjusted for management fees, taxes, and equity turnover rates.

Although TURN proposed a uniform rate of return, the utilities opposed it on the grounds that their own forecasts were appropriate because each trust fund was differently composed and managed. For purposes of these proceedings, we agree that overemphasis on short-term market recovery is not a conservative approach to the forecasted return and uniformity is less of an imperative than consideration of the actual composition of the trust fund portfolios.

The Settlement proposed different rates for PG&E than for SCE and SDG&E. The proposed pre-tax equity return of 8.75% for SCE and SDG&E is an increase over the rates they proposed, but not outside the evidence presented for a reasonable rate of return. Similarly, the 8.5% PG&E proposed would remain applicable to the HB3 trust funds which will eliminate equities by 2013 in order to finance the concurrent decommissioning. This is the same assumption adopted in the 2005 NDCTP and not unreasonable. For the DC trust funds, the Settlement states that after-tax returns will be adjusted on a pro-rata basis in order to yield the proposed $9 million annual contribution. (See below, Section 7.4.3.1.) PG&E's somewhat artificial calculation is that an assumed equity return of 8.13% return[31] would yield the proposed contribution. This is somewhat low but it matches rate of return evidence originally presented by SDG&E.

Based on the foregoing, we find that the equity rates of return proposed in the Settlement are reasonable and within the range of reasonable outcomes based on the evidence in the record.

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31 Reporter's Transcript at 853.

7.4.2. Fixed Income Rates of Return

For the fixed income portions of the trust fund portfolios, SCE originally assumed a 4.69% pre-tax return, SDG&E assumed 5.34%, PG&E applied 4.11%, and TURN agreed with SCE. The disparity is the result of different indices and assumptions, primarily whether to assume a municipal bond yield in the portfolios. DRA concluded the fixed income returns forecasted by the utilities were reasonable.

TURN's recommended debt return was based on 10-year municipal bonds and works out to the 4.2% post-tax return applicable to SCE and SDG&E in the Settlement. PG&E retained its original forecast for the HB3 trust funds. As noted above, the Settlement presumes a $9 million annual contribution to the DC trust funds without reliance on specific debt and equity returns.

We agree that despite some variations between the utilities, the forecasted returns are reasonable and the small modifications provided in the Settlement are within the range of reasonable outcomes based on the evidence in the record.

7.4.3. Contributions and Revenue Requirements

The Commission requires the utilities to update the trust fund balances to December 31, 2009 when calculating their contributions. Each utility has submitted an exhibit which describes the contributions and revenue requirements using the updated balances and the settlement terms which we have adopted herein.[32]

[32] Exhibit PG&E-20, Exhibit SCE-15, and Exhibit SDG&E-20.

7.4.3.1. PG&E

PG&E originally sought approval for $33 million in total trust fund contributions resulting in the grossed-up revenue requirements for 2010 set forth below:[33]

Diablo Canyon	$23.329
Humboldt	$16.982
Humboldt SAFSTOR	$ 9.218 (O&M)
Total	$49.528 million

This represents a $25.7 million increase from the currently authorized revenue requirement. When the trust fund balances are updated to December 31, 2009, without any other changes to the assumptions in the application, the required total contributions would decrease to $18.69 million.

One controversial issue in the proceedings was the proposed annual contribution for the DC units where parties advocated for amounts ranging from $23 million to zero. The Settlement was no less controversial in its proposal that PG&E's annual contribution be $9 million in what PG&E called a "black box" settlement derived from negotiation rather than specific evidence. PG&E contends this is a reasonable and informed compromise based on the litigation risks arising from various assumptions and arguments, including inadvertently omitted costs. We have previously said we disfavor such settlements where underlying assumptions are not disclosed because of the lack of transparency by

[33] Exhibit PG&E-1 at 8-2, Table 8-1.

which to verify them.[34] In contrast, this provision has some evidence to support it.

PG&E argued that it has good reasons for an increase to the DC cost estimate: $135 million in omitted labor termination expenses and use of a higher (35%) contingency factor. DRA disputed that there was evidence to support either argument and pointed out that using the updated trust fund balances and original application assumptions, PG&E would only need to make about $5 million[35] in contributions to the DC trust funds. PG&E replied that if the revised costs are incorporated with updated balances, the required annual contribution would rise to $29 million.

DRA's suggested contribution level was $1.8 million based on the updated fund balance and Settlement assumptions, except for substitution of the SCE LLRW burial escalation rate.[36] We agree with DRA that the evidence in support of a 35% contingency for the DC cost estimates is limited[37] and the omission of the claimed (and untested) labor termination costs is PG&E's error. However, this does not end the analysis. The goal of these proceedings is to adequately fund the trust funds based on reasonably accurate cost estimates. PG&E presented uncontested evidence that its updated annual DC contributions would

[34] D.88-02-030, 1988 Cal PUC 100 at 32-33.

[35] Exhibit PG&E-20.

[36] Exhibit DRA-10.

[37] When asked, PG&E's expert said he would not object to 35%. Reporter's Transcript at 203.

be $16.76 million[38] if it included the omitted labor termination costs and accepted the adjustments to its labor escalation rate and a five-year ramp down of equities after decommissioning begins, as set forth in the Settlement and adopted herein.

The record shows that SCE included labor termination costs without dispute and PG&E could argue that it should also have included them as a relevant cost (subject to protest for late submission). Moreover, the Commission is charged with assuring that the trusts are adequately funded by the ratepayers who receive the benefits of the generated power. There have been zero or nominal contributions approved for the DC trusts during the last two NDCTPs at a time when no detailed engineering studies have been done to assess contamination and certain costs have been omitted. Based on our review of the cost estimates and experience with rising costs as decommissioning becomes imminent, we find that these trusts are now underfunded.

Given these various considerations, a contribution of $9 million is within the range of likely outcomes had the Commission arrived at its own figure from a range of $5 - $16 million. Therefore, we find that the $9 million annual contribution is reasonable and justified and within likely litigation outcomes.

The HB3 trust funds have declined in value,[39] only non-qualified funds are at issue, and the overall contribution has increased by more than $3.5 million[40] assuming no other changes. Since this decision adopts the proposed changes to labor escalation and equity ramp down proposed in the Settlement, the HB3

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[38] *Id.*

[39] The HB3 non-qualified trust funds are predominately in fixed income investments.

[40] Exhibit PG&E-20.

contribution would increase by another $23,000. There is no dispute as to either proposed contribution and, therefore, we find PG&E's revised contribution to the HB3 trust funds to be just and reasonable.

7.4.3.2. SCE

The SONGS Unit 1 and PV trust funds are adequately funded so that no contributions are required in this triennial period. SCE originally sought approval for $64.537 million in total annual contributions for SONGS Units 2 and 3, which results in a total revenue requirement of $66.430 million.[41] This would have been a 43% increase over the requirements authorized in the 2005 NDCTP. However, the updated trust fund balances alone would cut that to about $47 million.[42] For the reasons discussed below, we adopt an even lower contribution amount.

TURN originally said no contributions were necessary for the SONGS Units 2 and 3 trust funds if SCE adopted TURN's proposed changes to the cost estimates. By our adoption of TURN's revised equity rate of return for SCE, as well as the updated trust fund balances, SCE's necessary contributions are reduced by half to about $23 million.[43]

DRA did not dispute the proposed contributions but argued that surplus funds were available in the SONGS Unit 1 trust funds that should be considered available for SONGS Units 2 and 3 decommissioning. However, we believe this

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[41] Exhibit Utilities-3 at 24, Table III-12.

[42] Reporter's Transcript at 851.

[43] Exhibit SCE-15.

view is premature given the uncertainties about radioactive waste disposal which could increase SONGS Unit 1 costs in the later phases.[44]

Based on the approved cost estimates for SONGS Units 2 and 3, inclusive of the revised equity rate of return we have adopted, SCE's revised contribution amounts and revenue requirements that result are just and reasonable.

7.4.3.3. SDG&E

SDG&E originally sought approval of an annual $15.284 million contribution to the SONGS Units 2 and 3 trust funds for its proportional share of the decommissioning expenses, plus continued recovery of $0.959 million related to SNF storage costs. Rather than seek a rate increase, SDG&E proposed to instead use overcollections in its NDAM and other balancing accounts or regulatory accounts to offset the revenue requirement. As discussed in Section 7.4.1 above, we are adopting a higher rate of return for SDG&E's equity investments which results in a lower contribution amount needed from ratepayers. Based on the updated trust fund balances, the company's annual contribution request has dropped to about $8 million.[45]

Based on the foregoing, we find SDG&E's revised contribution amount and proposal to fund the resulting revenue requirements out of existing balances to be just and reasonable.

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[44] There are also unresolved tax implications arising from fund transfers because California has not adopted certain changes in federal tax law relative to Internal Revenue Code § 468-A.

[45] Exhibit SDG&E-20.

7.5. Other Policy Issues

There was no objection to SCE's request to terminate its Decommissioning Tax Memorandum Account because it is unnecessary, and SCE has agreed to explore the feasibility of a separate NRC license to operate the ISFSI at SONGS Unit 1. As part of the proposed Settlement, the parties proposed solutions to other policy questions, which we adopt here. For example, in the next NDCTP, the utilities will provide, for information only, estimates of changes to funding for decommissioning associated with prospective license renewals for the SONGS Units 2 and 3 and DC Units 1 and 2. Also for the next NDCTP, the utilities will report the amount of pro rata share of funds held to meet NRC standards for License Termination, including copies of their most recent funding assurance letters to the NRC. For this NDCTP, we also accept the parties' agreement to allow the utilities to use different treatment of unrealized capital gains and losses when calculating the liquidation value of the trust funds.

The question of whether utilities should consider or assume in future NDCTPs that the trust funds will contain cash or some limited amount of equity investment for a period after shutdown or commencement of decommissioning is referred to Phase 2 of these proceedings.

7.6. Independent Panel

The level of decommissioning funds accumulated by the utility trust funds in California is high when compared with other states. It is unclear whether this is a result of appropriately conservative estimates, excessive caution, or mistaken assumptions. Therefore we agree with the parties that it is time to explore in detail the technical aspects of how decommissioning cost data is developed and presented so that the public, ratepayer advocates, and the Commission can better understand, analyze, and compare factors within the cost studies.

We adopt, with some modifications, the proposal in the Settlement to create an independent panel for the discrete task of improving the external review of cost estimates presented in NDCTPs. The panel will be comprised of individual decommissioning cost experts that worked with the utilities and TURN in these proceedings and, therefore, are also familiar with California's specific nuclear facilities: Nick Capik of ABZ, Geoffrey Griffiths of TLG, and Bruce Lacy of Lacy Consulting.[46] Lacy would sit as a representative of consumer interests. DRA is concerned that these experts will not be "independent" of the utilities, and seeks a role for Commission staff and non-Settling parties. However, DRA was more interested in being kept in the loop than in sitting on the panel. Fielder also argues that the panel would leave out important parties, although he admits he declined to participate.[47]

We disagree because these arguments miss the point and purpose of the panel's work. The Commission has an interest in having the data presented in a form that is useful and comparable. Here, it makes sense to identify the experts needed for a rarefied technical task who have also agreed to work together for the benefit of California ratepayers.[48] The panel will review volumes of technical data and their own proprietary models to develop recommendations to the Commission about how to improve transparency in decommissioning cost estimates for the benefit of the Commission and public, including Fielder and the

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[46] Reporter's Transcript at 779.

[47] Reporter's Transcript at 808.

[48] Reporter's Transcript at 805.

DRA. The result is advisory, relates to the presentation of cost data, and does not in any way substitute for the NDCTPs or limit future participation.

TLG and ABZ are among the few nationally recognized experts in the field of decommissioning costs. They have prepared the cost estimates for the utilities in prior NDCTPs and, consequently, are among the best informed persons about past practices and current trends. Lacy was TURN's expert witness on decommissioning costs on behalf of ratepayers and is familiar with the ABZ and TLG studies used in these proceedings. We agree with TURN and the utilities that this is a vitally important task best tackled by experts familiar with nuclear decommissioning costs and experiences nationwide, as well as the unique characteristics of California's individual sites. Notably, neither DRA nor Fielder offered similar witnesses at the evidentiary hearings.

Moreover, we adopt several steps to assure the panel's work is useful and comprehensible. Similar to what the Settlement proposed,[49] we require the panel to discuss the status of its work, listen to comments, and answer questions to be sure the resulting recommendations improve public review of cost estimates. Documents used in the development of the report would be available for review. The following opportunities for Commission staff and the parties to be included should occur:

- Within 30 days after adoption of this decision, the panel shall conduct a briefing about the panel's initial work plan.
- The panel shall conduct a briefing when it has completed the bulk of its work and considers its findings to be ready for presentation in draft.

[49] Opening Brief of SCE, SDG&E, PG&E and TURN at 2-3.

- The utilities shall provide reasonable notice of the briefings to the parties in these proceedings.
- Upon notice to the ALJ, a workshop will be scheduled within these proceedings where the panel will present the Report for review and comment by all parties and Commission staff, including response to questions and feedback.
- The panel will issue a final report with recommendations which shall be filed in the consolidated proceedings by March 1, 2010, unless the ALJ extends the date.

Although Fielder rather rhetorically describes the panel as a "star chamber" which would "hijack" the NDCTPs,[50] we think he misunderstands the limited nature of the assigned tasks. All of the identified technical issues were raised during the proceedings, in part due to frustration of the parties and the ALJ when trying to test, analyze, and compare bits and pieces of the cost estimates.[51] The differing cost formats, assumptions, and definitions made it quite difficult and sometimes impossible. We are concerned that going forward, as more decommissioning costs and expenses are submitted for approval, we will lack clear benchmarks and comparables by which to make fully informed judgments of reasonableness.

We find the scope of activities set forth in Section 2.2 of the Settlement Agreement to be appropriate. This is a unique opportunity to get information about decommissioning activities in other states, determine what cost and financial assumptions can be applied on a common basis, identify state-of-the-art ideas about how to reduce costs, and, importantly, to find a common format for

[50] Fielder's Post-hearing Reply Brief at 3.

[51] Reporter's Transcript at 780.

cost estimates to improve the quality of future scrutiny, analysis, and public participation.

The panel will limit its focus to PV, DC and SONGS Units 2 and 3 because these units are of similar size and design, still operating, and nowhere near commencement of decommissioning.[52] Fielder objected to the exclusion of HB3, but HB3 is a unique facility in many respects and is already into the decommissioning process.[53] Therefore, its exclusion does not diminish the usefulness of the panel's recommendations.

Finally, we adopt a $275,000 budget cap, instead of the proposed $250,000 budget cap, to funding of the panel's work, because of additional assigned tasks. The Settling Parties proposed that the costs be paid by the three utilities through the NDAM accounts and we agree that this nominal cost is an appropriate decommissioning expense. The actual allocation is based on the nuclear generating capacity of the DC Units 1 and 2, SONGS Units 2 and 3, and PV Units 1, 2, and 3.[54] It is our expectation that the panel's recommendations will enhance the Commission's ability to exercise its statutory review obligation, likely lead to decommissioning cost savings, and assist the public in its analysis of future decommissioning cost estimates. The nominal impact on rates should be readily recovered in the value of these probable results.

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[52] Reporter's Transcript at 800.

[53] Reporter's Transcript at 800-801.

[54] PG&E's allocation would be 44.78%, SCE's allocation would be 46.62%, and SDG&E's allocation would be 8.60%. See Attachment A to the Settling Parties' Post-hearing Opening Brief.

7.7. Reasonableness Review

We reject the proposal to extend the form of reasonableness review applied to Phase 1 of SONGS Unit 1 decommissioning expenditures to Phases 2 and 3 and to all phases of HB3. It is neither in the public interest nor reasonable in light of the whole record. The rebuttable presumption method was accepted as part of an unopposed settlement in the first NDCTP prior to any actual decommissioning activities. It employed a model drawn from another purpose (i.e., Energy Cost Adjustment Clause reviews)[55] that was not subject to close examination. Based on the knowledge and experience since gained by the Commission, it is clear that this is an important review process, influenced by speculative cost estimates and safety concerns, not suitable for an abbreviated method of oversight. 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.

Pub. Util. Code § 8325(c) allows the utilities rate recovery for "reasonable and prudent decommissioning costs." In D.99-06-007, the Commission authorized the commencement of SONGS Unit 1 decommissioning and a form of expenditure review that applied a rebuttable presumption of reasonableness to decommissioning activities based solely on completing work within an approved cost estimate. SCE was required to submit cost estimates and expenditures, along with its explanation of "material" differences in future NDCTPs. Absent "material" cost variations, the burden to show unreasonableness was shifted to other parties.

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[55] 86 CPUC2d 604, 615.

Unlike that presumption, the Commission described in the 2005 NDCTP its standard of reasonableness review for other decommissioning expenditures:

> [W]e define reasonableness for decommissioning expenditures consistent with prior Commission findings; i.e., that the reasonableness of a particular management action depends on what the utility knew or should have known at the time that the managerial decision was made.[56]

Going forward, we affirm this is the appropriate review to apply to actual decommissioning expenditures.

PG&E argued that it wanted "a process in place" by which it could evaluate how it would conduct decommissioning. It said that making advice letter estimates "and then having the completed projects reviewed, really isn't appropriate for this phase of the proceeding."[57] Essentially, PG&E contended that it was far better for the company to move review into the estimate phase instead of questions being raised after the fact. No actual review would be lost, said PG&E, because the presumption is rebuttable. We disagree.

The crux of PG&E's concern seems to be that the Commission would retroactively micromanage the decommissioning process. Its concern is somewhat misplaced because the Commission is not in the business of managing the decommissioning of a nuclear facility. Yet, the Commission is charged with assuring that ratepayers are not liable for unreasonable costs and that decommissioning activities are prudently undertaken. The utility wants to assure the Commission solely through its cost estimates that they will hire

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[56] D.07-01-003 at 7-8.

[57] Reporter's Transcript at 504-505.

appropriate people and spend appropriate amounts doing the right things safely. This is a leap of faith we are not prepared to take. We now know that cost estimates keep growing, unexpected things occur, the extent of contamination is unknown until it is removed, and that not all those expected to be hired have been hired at the time of the cost estimate.

SCE's arguments in support of the proposal centered on the claim that the presumption "worked well" for the Commission's review of its Phase 1 expenditures for SONGS Unit 1 and has been approved in each successive NDCTP.[58] The utility emphasized that the cost estimates were highly detailed and accurate and any party could challenge the costs even if within the estimate. Whether it "worked well" for SCE is not the same question as to whether it "works well" for the public. Cost estimates for remaining phases at the SONGS sites grew dramatically since the last NDCTP. SCE admitted learning a lot in Phase 1 as costs rose and it continued to grow the estimates for SONGS Units 2 and 3. Neither past use of the presumption, nor assurances of the reliability of a cost estimate, are persuasive reasons to alter the more complete, after-the-fact review set forth in D.07-01-003 for the benefit of ratepayers and the public.

SCE disputes Fielder's view that the presumption creates a "lighter burden of proof" and contends the utility has made the same evidentiary showing of expenses necessary to sustain a finding of reasonableness, notwithstanding the applicability of the presumption. SCE further notes that no one has disputed their costs, nor did Fielder even ask a question about them. This may be so, but it does not change the fact that the prudence review has been subsumed by the

[58] Reporter's Transcript at 478, 480.

cost analysis, nor does it address whether the presentation of the data is functionally penetrable by the parties and Commission staff in the time available during the NDCTP.

We have related policy concerns with application of a presumption, albeit rebuttable, to the most important part of our review of the decommissioning of California's nuclear facilities. For example, cost estimates are not as reliable as the utilities claim, nor are they the final word as to what activities are conducted and by whom. The fact there is wide agreement that cost estimates are opaque, inconsistent between utilities, and rely on disputed assumptions, underscores the limited reliability of an estimate even as decommissioning approaches. That is why the work of the independent panel is so important for improving future review of cost estimates. It also illustrates why the Commission and other parties may have difficulty reviewing the expenditures within the time available and matching them to work scope in order to test the presumption.

Another concern is that SCE and PG&E are acting as their own general contractors for the decommissioning. This is uncharted territory which may yield cost benefits to ratepayers but includes risk of myopia from exclusion of third-party perspectives about operational practices affecting costs. Fielder called it a "conflict of interest" and said, "[O]nly the utilities will know what they did and when they did it…."[59] Similarly, at the evidentiary hearings, TURN's counsel said:

> Essentially, they're asking the Commission to decide that that money belongs to the utility, not to the ratepayers, and they want an upfront guarantee that they can spend these funds irrespective of

[59] Intervenor Scott Fielder's Reply Brief at 5.

> what facts may come to light in the future or how the utilities actually behave, and perhaps most importantly, whether actions that the utility has taken are contributing to the increase of those costs.[60]

TURN dropped its opposition to this proposal as part of the Settlement, presumably because it gained agreement on the independent panel and other changes in utility assumptions. However, that does not eliminate the importance of these concerns for the Commission.

The policy problem is amplified by the fact that neither PG&E nor SCE officially submitted their decommissioning plans to the NRC for substantive review because such submission is not required unless in connection with a license termination. Absent NRC oversight, the NDCTP seems to be the only regulatory review of their actual decommissioning plans. Therefore, the Commission is the front-line agency in position to examine whether the decommissioning is done prudently. Adoption of the reasonableness presumption would inappropriately submerge the character of the activities within a cost test that fixes the burden of proof.

We are not comforted by the utilities assurances that the data is submitted for review regardless of whether there are material cost differences, and parties have the ability to challenge costs and prudence even if the presumption applies. If the presumption does not alter the evidentiary showing, then it seems of little benefit to the utility. 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

[60] Reporter's Transcript at 499.

solely based on cost. Furthermore, the inclination to overestimate costs could arise.

Based on the foregoing, we conclude that it is not in the public interest nor reasonable in light of the whole record to provide, going forward, a presumption of reasonableness for decommissioning activities which are completed within cost estimates. This finding is sufficient to reject the Settlement as a whole.

8. Conclusion

Based on the foregoing discussion, we decline to adopt the proposed Settlement primarily because the provision relating to expansion of the reasonableness presumption for decommissioning activities completed within cost estimates is not in the public interest and not reasonable in light of the whole record. However, based on the evidentiary record, we adopt almost all of the other terms of the proposed Settlement which generally accepted the initial cost estimates and decommissioning expenditures submitted by the utilities, with a minor adjustment to PG&E's labor costs.

The contributions were adjusted, as proposed in the Settlement, based on trust fund balances updated to December 31, 2009, and for SCE and SDG&E also adjusted for forecasted higher rates of return on equity. We also adopt the settled upon annual contribution by PG&E of $9 million for the DC trust funds based on evidence supporting that it was within the range of likely outcomes absent the Settlement. We also adopted a plan from the Settlement to initiate an independent panel of decommissioning experts to help the Commission guide the utilities into a more accurate, transparent, and comparable presentation of cost data. The panel will deliver a report to the Commission and parties in March 2010, which makes recommendations that will, hopefully, improve Commission and public review of nuclear decommissioning in California.

9. Comments on the Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 and comments were allowed under Rule 14.3. Comments were filed on June 28, 2010, and reply comments were filed on July 1, 2010 by Fielder. Based on the comments and reply comments, certain technical corrections have been made.

10. Assignment of the Proceedings

Timothy Alan Simon is the assigned Commissioner and Melanie M. Darling is the assigned ALJ in these proceedings.

Findings of Fact

1. PG&E filed A.09-04-007, its 2009 NDCTP on April 3, 2009. SCE and SDG&E jointly filed A.09-04-009 for the 2009 NDCTP.

2. SCE, SDG&E, PG&E, and TURN proposed a Settlement Agreement on December 18, 2009 that resolved all disputed issues in these consolidated proceedings.

3. The two parties that opposed the Settlement, DRA and Fielder, raised important questions about some provisions of the Settlement, particularly related to the reasonableness review of decommissioning expenditures, as well as the structure and process of the independent panel.

4. The active parties in the proceedings are representative of the stakeholders, and each has ably and vigorously pursued the interests of its constituency.

5. SCE, SDG&E, and PG&E each submitted uncontested evidence that they had complied with orders from the Commission in D.07-01-003, the 2005 NDCTP.

6. SCE, SDG&E, and PG&E each provided reasonable 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.

7. SCE and SDG&E may overestimate waste removal costs when making estimates of future costs for the SONGS units due to the ownership of the underlying land by the United States Department of the Navy which has not yet defined the standard to which the land must be returned at the time of license termination.

8. SCE, SDG&E, and PG&E each documented that they had undertaken various, previously approved decommissioning activities and incurred the identified expenditures for them at the SONGS Unit 1 and HB3, respectively. The documentation explained differences from prior cost estimates.

9. The proposed trust fund contributions, based on the original cost estimates in the applications, have declined during the proceedings because the trust funds have increased in value since the applications were filed.

10. The parties offered different forecasted rates of return for trust fund equity investments, partly due to what length of time was used to average projected returns. Overemphasis on short-term market recovery is not a conservative approach to forecasting rates of return.

11. The parties offered different forecasted rates of return for trust fund fixed income investments, partly due to whether a municipal bond yield was assumed for the portfolios.

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

13. The DC trusts are underfunded. Based on updated trust fund balances, the evidence supports an annual contribution for the DC trust funds between $5 million and $16 million.

14. The Commission, interested parties, and the public would benefit from the utilities employing common forms of presenting cost estimate data, including identification of common assumptions, cost factors, and other shared cost elements among different California nuclear units. Public benefits would likely include more detailed reviews of proposed estimates and a reduction of future decommissioning costs.

15. An independent panel of decommissioning experts who have worked on the cost estimates in these proceedings would be best suited to the technical task of sorting through proprietary methodologies, national decommissioning data, and site specific challenges to advise the Commission about a model form for future cost estimates.

16. An independent panel should provide opportunities for the Commission, its staff, and other parties to be briefed, ask questions, and offer comment on the panel's work to assure it is sufficiently transparent and useful. A written report is the best way to acquire the panel's final recommendations.

17. We expect the panel's recommendations will enhance the Commission's ability to exercise its statutory review obligation, likely lead to decommissioning cost savings, and assist the public in its analysis of future decommissioning cost estimates. Funding is capped at $250,000, is an appropriate administrative decommissioning expense, and will be paid by the utilities through the NDAM accounts pro rata based on nuclear generating capacity at DC, SONGS, and PV.

18. Pub. Util. Code § 8325(c) directs the Commission to examine the decommissioning costs for which the utilities seek rate recovery to be sure that ratepayers only pay for reasonable and prudent decommissioning costs.

19. In the first NDCTP, the Commission accepted a settlement whereby SCE and SDG&E were authorized to commence Phase 1 of the decommissioning of SONGS Unit 1 and were permitted to assert a rebuttable presumption of reasonableness, which included the prudence of the activities, if the work completed came within the previously approved cost estimate.

20. Past use of a presumption of reasonableness, as adopted in a settlement more than a decade ago for the very first decommissioning activities, is insufficient basis to continue the practice without further scrutiny. The lack of transparency and incomparability of cost estimates, combined with a short-time frame for discovery within the NDCTP, limit the effectiveness of our review of the decommissioning activities and expenditures.

21. SCE will act as general contractor for the Phases 2 and 3 of SONGS Unit 1 decommissioning. SCE did not formally submit its decommissioning plan to the NRC because it is not required when there is no immediate linkage to a license termination.

22. PG&E will act as general contractor for all phases of the HB3 decommissioning. PG&E has not formally submitted its decommissioning plan to the NRC because it is not required when there is no immediate linkage to a license termination.

23. The public interest is best served when the Commission separately examines both the decommissioning costs incurred for reasonableness and the utility's decommissioning activities for prudence, after the activities have taken place and the expenses have been incurred.

24. SCE's Decommissioning Tax Memorandum Account has resulted in only *de minimis* adjustments.

25. The transfer of funds from non-qualified trust funds for the decommissioning of SONGS Unit 1 to the qualified trust funds for the decommissioning of SONGS Units 2 and 3 should not be required at the present time because of several uncertainties about actual and final reasonable costs, actual rates of return for trust fund investments, and actual tax consequences of such transfers.

26. Issues related to what investment strategies should be followed by trust funds when decommissioning of a nuclear generation unit has commenced, are deferred to Phase 2 of these proceedings.

Conclusions of Law

1. The proposed contested Settlement is rejected as a whole because it is not in the public interest nor reasonable in light of the whole record.

2. 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 if the proposed revenue requirements would result in just and reasonable rates.

3. SCE, SDG&E, and PG&E are in compliance with prior decisions applicable to decommissioning, including the Ordering Paragraphs 6, 7, and 8 of D.07-01-003.

4. As shown in their joint application, supporting testimony (including attachments to testimony), and filings, SCE's and SDG&E's (a) updated $184.4 million (100% share, 2008$) SONGS Unit 1 decommissioning cost estimate for the remaining work and (b) updated $3,658.8 million (100% share, 2008$)

SONGS Units 2 and 3 decommissioning cost estimates, are reasonable and should be adopted.

5. SCE and SDG&E's $207.2 (100% share, 2008$) cost of decommissioning work at SONGS Unit 1 between July 1, 2005 and December 31, 2008 is reasonable and prudent and is approved. The presumption of reasonableness provided to decommissioning costs for Phase 1 of SONGS Unit 1 in D.99-06-007 is unaffected by rejection of the method in these proceedings for other phases of SONGS Unit 1 and other nuclear generation units.

6. As shown in its application, supporting testimony (including attachments to testimony), and filings, SCE's updated $708.7 million (SCE's share, 2007$) PV decommissioning cost estimate is reasonable and should be adopted.

7. As shown in its application, supporting testimony (including attachments to testimony), and filings, SDG&E's updated ratable share of the decommissioning costs for SONGS Units 2 and 3 of $731.8 million is reasonable and should be adopted.

8. SDG&E may reasonably rely upon SCE, as the majority owner of and exclusive operating and decommissioning agent for SONGS Units 1, 2, and 3, to make reasonable efforts (a) to retain and utilize sufficient qualified and experienced personnel to pursue any decommissioning-related activities for these units under their control effectively, safely, and efficiently, (b) to forecast the costs of low-level radioactive waste storage conservatively, and (c) to establish an appropriate contingency factor for inclusion in the decommissioning revenue requirements, as required by the Commission in D.07-01-003, subject to the proviso that SDG&E shall review and provide such advice and consent as may be necessary and appropriate to the interests of SDG&E as a minority owner and/or on behalf of the interests of SDG&E's retail electric customers.

9. For purposes of this NDCTP, SCE's and SDG&E's trust fund contributions shall be based on 8.75% pre-tax equity returns and 4.2% post-tax debt returns. Taxes on realized and unrealized capital gains and losses shall be treated as described in Section 3.6 of the Settlement Agreement.

10. The SONGS Unit 1 and PV trusts are adequately funded for this triennial period and no contributions are required.

11. SCE's updated contributions of $22.73 million to SONGS Units 2 and 3 qualified and non-qualified trust funds, using the revised rates of return and updated trust fund balances, will result in just and reasonable rate increases.

12. SDG&E's updated contribution of $8.07 million for SONGS Units 2 and 3 qualified and non-qualified trusts, using the revised rates of return and updated trust fund balances, plus continued recovery of $0.959 million in SNF storage costs, is reasonable. SDG&E will use overcollections in NDAM to offset the revenue requirement.

13. As shown in its application, supporting testimony (including attachments to testimony), and filings, PG&E's updated cost estimates (e.g., $1,828.35 million in 2008$ for DECON option) for DC units decommissioning, with adjusted labor escalation rates as described in Section 7.2.4 of the decision, are reasonable and should be adopted.

14. PG&E's updated cost estimate of $499.8 million (2008$) for HB3 decommissioning costs, with adjustments as described in Section 7.2.3 of the decision, is reasonable and should be adopted.

15. PG&E's preparatory decommissioning activities and expenditures totaling $63.4 million, largely for with respect to licensing, design, fabrication, and construction of the ISFSI, were reasonable and prudent.

16. The negotiated annual contribution of $9 million to the DC qualified trusts is reasonable and should be adopted.

17. For purposes of this NDCTP, funding assumptions for PG&E include that liquidation values of the trust funds as of December 31, 2009 will be computed netting all realized and unrealized capital gains and losses and equities in DC trust funds will be ramped down over a five-year period after shutdown.

18. PG&E's requested annual contribution of $13.633 million to the HB3 non-qualified trust, revised to reflect updated trust fund balances and other agreed upon assumptions as noted in the Decision, is reasonable and will result in just and reasonable rate increases.

19. PG&E's forecasted expenses and revenue requirement of $9.218 million in 2010 to cover the costs of operating and maintaining the HB3 site in a safe condition (SAFSTOR), with attrition for 2011 and 2012 are reasonable and should be adopted. PG&E shall track its actual SAFSTOR expenses and make a "true-up" contribution to, or withdrawal from, the decommissioning trusts based on whether the amount collected in rates is greater than or less than the expenses actually incurred. To the extent that contributions differ from estimates, PG&E will report on the differences in the next NDCTP where the differences will be subject to reasonableness review.

20. It is in the public interest for the utilities and TURN to create an independent panel to review the decommissioning-related issues, as identified in Section 2.2 of the Settlement Agreement attached hereto as Appendix B, and follow the procedural steps for completing the work, including issuance of a final report with recommendations which shall be filed in these proceedings, as set forth in Section 7.6 of this decision. The report shall be filed in the consolidated proceedings by March 1, 2011, unless the ALJ extends the date.

21. The independent panel's work should be funded by an amount not to exceed $275,000 paid by the utilities through the NDAM account allocated based on the nuclear generating capacity of the DC, SONGS and PV units. This is an appropriate decommissioning expense.

22. The Commission should be informed by the utilities, in the next NDCTP applications, of contribution estimates that assume successful completion of license renewal.

23. The Commission should be informed by the utilities, in the next NDCTP applications, of the pro rata share of funds accumulated for NRC License termination (radiological decommissioning to meet the NRC standard for license termination) and receive copies of their most recent funding assurance letters (pursuant to 10 C.F.R. 50.75) sent to the NRC.

24. Prior to the development of the SONGS cost estimates for the next NDCTP, the Commission (along with other state agencies and officials and with SCE and SDG&E) should formally ask the United States Department of the Navy to (1) clarify the applicable site restoration and remediation standards that will be required to terminate the SONGS site lease, and (2) execute a document with SCE and SDG&E that explicitly reflects such clarified standards.

ORDER

IT IS ORDERED that:

1. Within ten (10) days of the effective date of this Decision, Southern California Edison Company 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 Decision, subject to Energy Division determining that the revised tariffs are in compliance with this Decision. The compliance advice letter shall be served on the service list for the consolidated proceedings and shall describe how Southern California Edison Company will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2009 nuclear decommissioning trust fund balances. The updated information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2010-2012. 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 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. San Diego Gas & Electric Company will clearly identify the overcollections in its Nuclear Decommissioning Adjustment Mechanism which it will use to offset the revenue requirement, subject to Energy Division determining that the offsets are in compliance with this Decision. The compliance advice letter shall be served on the service list for the consolidated proceedings and shall describe how San Diego Gas & Electric Company will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2009 nuclear decommissioning trust fund balances. The updated information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2010-2012. 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.

3. Within ten (10) days of the effective date of this Decision, Pacific Gas and Electric Company 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 Decision, subject to Energy Division determining that the revised tariffs are in compliance with this Decision. The compliance advice letter shall be served on the service list for the consolidated proceedings and shall describe how Pacific Gas and Electric Company will implement the terms adopted in this Decision, including updating the revenue requirements to incorporate the December 31, 2009 nuclear decommissioning trust fund balances. The updated information shall serve as the basis for the Internal Revenue Service Schedule of Ruling Amounts for years 2010–2012. 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. Pacific Gas and Electric Company shall serve testimony in its next triennial review of nuclear decommissioning trusts and related decommissioning activities 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 decommissioning related activities for the nuclear generation facilities under its control.

5. Pacific Gas and Electric Company shall track its actual SAFSTOR expenses during the triennial period and report and explain any differences in Pacific Gas and Electric Company's next Nuclear Decommissioning Cost Triennial Proceeding application.

6. Immediately after the effective date of this Decision, Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall work with The Utility Reform Network to create an independent panel to review the decommissioning-related issues, as identified in Section 2.2 of the Settlement Agreement attached hereto as Appendix B. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall assure that the panel follows the procedural steps for completing the work, including issuance of a final report with recommendations which shall be filed in these proceedings, as set forth in Section 7.6 of this Decision.

7. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall file a joint advice letter no later than November 30, 2010, and serve it on the service list for these proceedings, which identifies the total expenses incurred by the independent panel, the appropriate allocation between the utilities, and the proposed adjustments to each utility's Nuclear Decommissioning Adjustment Mechanism account.

8. In the next Nuclear Decommissioning Cost Triennial Proceeding applications, Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall provide contribution estimates that assume successful completion of license renewal.

9. In the next Nuclear Decommissioning Cost 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 License termination (radiological decommissioning to meet the Nuclear Regulatory Commission 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 Nuclear Regulatory Commission.

10. Within one year of the date of this decision, the Commission's Executive Director, on behalf of the entire California Public Utilities Commission, shall make a formal written request along with Southern California Edison Company and San Diego Gas & Electric Company, to the United States Department of the Navy to clarify the applicable site restoration and remediation standards that will be required to terminate the San Onofre Nuclear Generating Station site lease, and shall meet and confer with the United States Department of the Navy to attempt execution of an amended site lease contract that explicitly reflects such clarified standards, prior to the development of the San Onofre Nuclear Generating Station cost estimates for the next Nuclear Decommissioning Cost

Triennial Proceeding. Southern California Edison Company and San Diego Gas & Electric Company shall report to the Commission any responsive information received by either utility in their next Nuclear Decommissioning Cost Triennial Proceeding application.

11. Application (A.) 09-04-007 and A.09-04-009 remain open for Phase 2 and to receive additional filings ordered in Phase 1.

This order is effective today.

Dated July 29, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

APPENDIX A

List of All Exhibits

APPENDIX B

Settlement Agreement

APPENDIX C

Pre-Settlement Issues

1. Compliance with D.07-01-003

During the 2005 NDCTP, which was resolved by adoption of a settlement, the Commission ordered the utilities to serve testimony in the 2009 NDCTP in three areas: 1) the use of qualified and experienced personnel, 2) a conservative forecast of costs for low level radioactive waste storage, and 3) a conservative and appropriate contingency factor for inclusion in each utility's decommissioning revenue requirements. SCE and SDG&E were also directed to evaluate in their next application whether there were any excess funds in the SONGS 1 trust funds[1] and, if so, could they and should they be transferred to the SONGS 2 & 3 trust funds. The utilities argued they complied with all of these requirements in their applications and initial testimony, but TURN & DRA initially questioned this especially as to whether SONGS 1 trust funds could be transferred or refunded to ratepayers.

In D.07-01-003, the Commission concluded it was preferable for the utilities to demonstrate in future triennial reviews that it engaged employees, contractors, or consultants trained to plan and perform decommissioning of nuclear plants under their control and ordered the utilities to serve testimony in the 2009 NDCTP that establishes they have made all reasonable efforts to do so. The Commission also ordered the utilities to research costs for storage and

[1] As a result of earlier tax laws, there are both Qualified and Non-Qualified trust Funds established for SONGS 1 and HB3.

disposal of low level radioactive waste (LLRW), develop a conservative forecast for LLRW costs, and to serve testimony in the 2009 NDCTP as to their efforts.

In the same decision, the Commission examined proposed contingency factors from the 2005 NDCTP ranging from 25% to 35, as well as historical factors as high as 50%. The Commission observed that a declining contingency factor, if properly determined, could reflect improved accuracy of decommissioning cost estimates in addition to protecting against errors and unforeseen costs. All parties were directed to conduct research and analysis to develop a conservative contingency factor and the utilities were ordered to serve testimony in the 2009 NDCTP as to their efforts.

2. DRA

DRA generally found the decommissioning cost estimates provided by the utilities for each of the nuclear generation units were reasonable and specifically agreed with the escalation methodologies for labor and materials (if updated), the 25% contingency factor, the LLRW burial rates, and the utilities' rate of return results. Therefore, DRA recommended approval of the estimates for all nuclear generation units (NGU) as reasonable.

DRA's concerns were primarily related to the revenue requirements proposed by PG&E and SCE, but also included whether there are excess trust funds for SONGS 1 and if they should be returned to ratepayers. DRA agreed with the proposed zero contribution for SONGS 1 and also said any transfer of purported excess funds in the SONGS 1 trust funds to other SONGS trust funds was premature. Nonetheless, DRA argued that the "excess funds" could be viewed as an offset to the SCE/SDG&E revenue requirements for SONGS 2 & 3 without transferring any funds which might lead to unintended tax consequences.

In addition, DRA recommended the Commission do the following:

- Reduce $23.3 million revenue requirement for DC Units 1 & 2 to $0 based on DRA's escalation rates and rates of return
- Reduce the $16.692 million revenue requirement for HB3 to $0 based on DRA's escalation rates and rates of return
- Reduce the SAFSTOR O&M expenses from $9.218 million in 2010 to $8.884 million in 2010, with attrition, based on DRA's escalation rates
- Adopt SCE's 6.7%[2] LLRW burial escalation rate for all units and reject PG&E's use of 7.5%
- Require all authorized contributions be placed into the Qualified Trust Funds rather than into Non-Qualified Trust Funds

DRA supported PG&E's request for a presumption of reasonableness for decommissioning expenses for all phases of HB3 if the scope of work and actual cost for decommissioning projects are within the approved 2009 cost estimates.

3. TURN

TURN had numerous objections and concerns about the utilities' applications in this proceeding. In its Protest, TURN initially argued that the SCE/SDG&E application should be rejected due to a bad faith failure to perform the previously described excess trust fund analysis required in the settlement agreement adopted in the 2005 NDCTP as set forth in D.07-01-003. TURN's experts also critiqued the cost estimates provided and recommended a higher return on equity and debt than all three of the utilities and a lower escalation rate for PG&E company labor.

TURN offered the following recommendations to the Commission:

[2] In Exhibit SCE-14, SCE corrected its calculation for LLRW burial escalation rate to be 6.93%. This figure was used in the settlement agreement for SCE and SDG&E.

- Discontinue SCE/SDG&E decommissioning trust fund collections for all units, including:
    - Make reductions to the license termination, site restoration, and Spent Nuclear Fuel (SNF) management cost estimates for SONGS 2 & 3 based on similar estimates for DC units
    - Reject SCE's adjustments to the cost estimate for PV units completed by the majority owner, Arizona Public Service (APS)
- Require the utilities to identify the impact of license renewal for their respective units
- Require the utilities to de-comingle funds in the trust funds in order to clarify reports of trust fund adequacy to the Nuclear regulatory Commission (NRC)
- Require SCE to de-link its ISFSI license for SONGS 1, 2, and 3 from its Part 50 operating license from NRC
- Direct the utilities to improve strategic planning for radioactive waste disposal
- Adopt SCE's labor escalation rate of 3.13% for all utilities
- Apply forecast of 10.05% pre-tax equity rate of return through 2022 for all utilities
- Apply forecast of 4.69% pre-tax fixed income for all utilities
- Apply a uniform five-year step-down to eliminate equity from decommissioning trust funds after decommissioning commences
- Prohibit cash in the investment portfolio
- Clarify treatment of realized capital losses in trust fund liquidation values

Based on the foregoing assumptions, TURN estimated no contributions would be required by PG&E for any units.

4. Scott Fielder

Fielder identified three basic issues: the contingency factor, LLRW disposal rates, and the proposed modification of the Commission's reasonableness review process. Fielder offered the following recommendations to the Commission:

- Apply a 35% contingency factor to all utility decommissioning cost estimates
- Apply the $509/cubic foot composite figure for LLRW disposal costs adopted by the Commission in 1999 GRC decision
- Direct that re-calculation of DC cost estimates should be done using a computerized cost analysis system such as the one used by ABZ, Inc.[3]
- Reject any change to the standard or process of reviewing expenses incurred for decommissioning activities to determine if the expenses were reasonable and prudent

5. Merced and Modesto Irrigation Districts

The Merced Irrigation District and Modesto Irrigation District (collectively "Districts") are customers of PG&E and filed a response to the PG&E application. The Districts expressed concern about PG&E's proposed doubling of its revenue requirement for decommissioning over the next three years and the fact that these costs will likely continue to grow into the foreseeable future. They did not protest the application, nor offer any substantive analysis for the Commission. Instead, the Districts asked the Commission to "carefully review PG&E's

[3] ABZ, Inc. (ABZ) is one of two national decommissioning consultants most often used by owners of nuclear generation units to make periodic estimates of the cost to decommission the units. ABZ uses a proprietary software called "Decommissioning Cost Analysis System (DECAS)."

rationale, data, and justification for the proposed increases" to assure the proposed revenue requirements are warranted.

(END OF APPENDIX C)

APPENDIX D
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(END OF APPENDIX D)

ATTACHMENT 2C

SOUTHERN CALIFORNIA EDISON TIER III REQUEST LETTER

CALIFORNIA PUBLIC UTILITIES COMMISSION

FEBRUARY 13, 2014

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Megan Scott-Kakures
Vice President, Regulatory Operations

November 18, 2013

ADVICE 2968-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Request for (1) Authorization of Disbursements from the Master Trusts for San Onofre Nuclear Generating Station; (2) Approval of Tier 2 Advice Letter Process for Future Disbursements; (3) Designation of Trust Amounts Set Aside for NRC License Termination; and (4) Approval of Balancing Account

I. PURPOSE AND INTRODUCTION

Pursuant to General Order 96-B, Southern California Edison Company (SCE) respectfully submits this Tier 3 advice letter requesting a resolution from the California Public Utilities Commission (Commission or CPUC) that:

1. Authorizes SCE to obtain interim disbursements of up to $214 million (SCE Share) from the Master Trusts[1] for San Onofre Nuclear Generating Station Unit Nos. 2&3 (SONGS 2&3)[2] for SONGS 2&3 decommissioning expenses incurred in 2013;

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1 The decommissioning trusts are governed by the Southern California Edison Company Nuclear Facilities Qualified and Non-qualified CPUC Decommissioning Master Trust Agreements for San Onofre and Palo Verde Nuclear Generating Stations (Master Trusts). The Master Trusts provide that the advice letter process can be utilized for obtaining disbursements. Specifically, section 2.01 of the Master Trust Agreements states: "The Trustee shall make payments of the Decommissioning Costs in accordance with the following procedures:...(4)(d) a CPUC Order authorizing either Interim Disbursements or Final Disbursements." Section 1.01 (9) of the Master Trust Agreements provide that "CPUC Order shall mean an order or resolution issued by the CPUC after the Company, the Committee, the CPUC Staff, the Trustee, and other interested parties have been given notice and an opportunity to be heard. The order may be issued with or without hearing or *by the CPUC Advice Letter procedure* or comparable procedure." (emphasis added)

2 SCE is not proposing to be reimbursed by the trust funds designated for SONGS 1 and Palo Verde Nuclear Generating Station Units 1, 2, and 3 to pay expenses incurred in the decommissioning of SONGS 2&3.

2. Approves a Tier 2 advice letter procedure, consistent with the process established in Decision (D.) 11-07-003, for (1) SCE to seek disbursements for decommissioning costs incurred in 2014 and future periods until adoption of a final SONGS 2&3 decommissioning activities plan and cost estimate by the Commission, and (2) the Commission to review SONGS 2&3 decommissioning activities and recorded costs;

3. Designates which portions of the trust funds for SONGS 2&3 should be set aside for NRC License Termination;

4. Authorizes SCE to establish a SONGS Operations and Maintenance (O&M) Balancing Account (SOMBA) to record the difference between actual SONGS 2&3 O&M expenses, trust fund disbursements, and the authorized SONGS 2&3 O&M expenses included in customer rates.

SCE anticipates filing an application in 2014 that will seek Commission approval of a SONGS 2&3 site-specific, detailed radiological and non-radiological decommissioning and fuel management plan and cost estimate. The approval sought by this Tier 3 AL and subsequent Tier 2 ALs will authorize disbursements from the Master Trusts until such time (estimated to be late-2015) as the Commission has issued a decision that approves SCE's site-specific SONGS 2&3 decommissioning actitivies plan and detailed cost estimate,[3] and that grants authority to obtain disbursements from the Master Trusts for SONGS 2&3 decommissioning costs. In addition, SCE does not seek, by this advice letter, any rate increase or additional funding for the Master Trusts. The trusts have accumulated funds for more than 25 years, funded by the SCE customers pursuant to the Nuclear Facilities Decommissioning Act of 1985 ("Decommissioning Act").[4] Accordingly, SCE seeks to defray SONGS 2&3 decommissiong costs by utilizing the Master Trusts for their intended purposes.

SCE would not seek recovery of expenses disallowed in Investigation (I.) 12-10-013 (OII). SCE would exclude from its Decommissioning Trust request any recorded expenses found unreasonable in the OII.

II. <u>BACKGROUND</u>

On June 7, 2013, SCE announced plans to permanently retire SONGS 2&3. On June 12, 2013, SCE submitted a Certification of Permanent Cessation of Power Operations to the Nuclear Regulatory Commission (NRC), certifying that SCE has permanently

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[3] The ABZ study submitted in the NDCTP is used for determining the approximate level of funding required, and does not provide the detailed schedule, plans, and cost-estimates that will be provided to the NRC or that will provide the basis for the decommissioning cost estimate in SCE's application at the Commission.

[4] California Public Utilities Code, Section 8321, et seq.

ceased power operations of SONGS 2&3, surrendering SCE's authority to operate the units. SCE submitted to the NRC a Certification of Permanent Removal of Fuel for Unit 3 on June 28, 2013, and for Unit 2 on July 23, 2013. As a result of these submittals, SCE now holds an NRC license that does not permit power operations but does authorize the possession of the SONGS facilities and licensed material. SCE no longer has authority under its operating licenses to load fuel into the reactors at SONGS 2&3.

The permanent retirement of SONGS 2&3, approximately nine years before the expiration of the NRC operating licenses for the units in 2022, represents a change of circumstance not contemplated in the decommissioning cost estimates previously submitted and approved by the CPUC in prior Nuclear Decommissioning Cost Triennial Proceedings (NDCTPs). Under the sequence of events that was previously contemplated, SCE would have submitted a site-specific decommissioning activities plan and detailed cost estimate for review by NRC and approval by this Commission at least five years prior to the expiration of the operating licenses. NRC regulations at 10 CFR 50.75(f)(3) and (4), for example, would have required SCE to submit preliminary decommissioning plans and cost estimates for the NRC's review beginning about 5 years prior to the projected expiration of the operating licenses. Section 2.01(7) of the Qualified and Non-Qualified Master Trust Agreements further state:

> One year prior to the time decommissioning of a Plant or Plants is estimated to begin, the Company shall apply for CPUC approval of the estimated cost and schedule for decommissioning each Plant or Plants. Upon approval of the cost and schedule for decommissioning each Plant or Plants, the CPUC shall authorize Interim Disbursements from the applicable Fund to pay Decommissioning Costs.[5]

The timing contemplated by the Master Trust Agreements would have permitted SCE to seek approval of a site-specific decommissioning plan and detailed cost estimate, and obtain disbursements from the Master Trusts for decommissioning-related expenses, as the units approached the expiration of the operating licenses. Given the change of circumstances resulting from the early retirement of SONGS, SCE submits this advice letter requesting Commission approval for interim disbursements from the Master Trusts and other relief, in connection with SONGS 2&3 decommissioning activities and costs.

III. DISCUSSION

SCE further explains below the basis for the relief sought. SCE submits the following additional information in support of this Tier 3 AL:

> Attachment 1 – Summary of decommissioning costs for the first 18 months of decommissioning through December 31, 2014 (recorded from June, 2013 to September, 2013 and forecast from October, 2013 to December, 2014);

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[5] Section 2.01(7) of Qualified Master Trust Agreement, and Section 2.01(7) of Non-qualified Master Trust Agreement.

Attachment 2 – Correlation of estimated costs to the most recent ABZ estimate submitted in the NDCTP; and

Attachment 3 – Overview of decommissioning process, and SCE's initial decommissioning planning activities, near-term work, and SONGS staffing plans;

A. Interim Disbursements

SCE estimates the expenditure of up to $282 million (100 percent share) of SONGS 2&3 decommissioning costs through December 31, 2013. SCE requests the Commission to authorize disbursements of up to $214 million (SCE Share)[6] from the Master Trusts for SCE's share of these costs.

As shown in Attachment 1, the decommissioning costs incurred in 2013 include (1) Base O&M necessary to ensure the radiological safety and security of SONGS, and to commence decommissioning activities;[7] (2) capital expenditures related to the Independent Spent Fuel Storage Installation (ISFSI) and site-security projects; and (3) other costs such as workers compensation, insurance, and severance (if allowed as decommissioning costs under tax rules). More specifically, as explained in further detail below, the Base O&M decommissioning costs in 2013 are necessary for: (1) commencing a site-specific SONGS 2&3 decommissioning activities plan and detailed cost estimate, and preparing decommissioning-related submittals to the Nuclear Regulatory Commission (NRC);[8] (2) managing used fuel stored at SONGS; and (3) paying for other near-term non-radiological decommissioning costs, including the option to pay for employee-related decommissioning costs allowable under the Nuclear Facilities Decommissioning Act of 1985 (Decommissioning Act),[9] if certain federal tax issues are resolved favorably.[10] SCE expressly requests the authority to propose a different means to recover the severance expenses incurred in decommissioning, if payment from the decommissioning trust would compromise the beneficial tax status of the trusts or if another cost-recovery alternative is appropriate. As shown in Attachment 2, the estimated costs for Base O&M, capital expenditures, and other costs submitted in this Tier 3 AL are consistent with those estimated in the ABZ study submitted in July 2013 in the NDCTP.

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6 The SONGS participants' respective shares of the decommissioning costs for SONGS 2&3 are governed by Section 22 of the Second Amended Operating Agreement for SONGS. SCE's and the City of Anaheim's shares of these decommissioning costs are also governed by the Settlement Agreement Relating to SONGS by and between SCE and the City of Anaheim, dated December 20, 2005. Based on these agreements, SCE's share is approximately 76 percent of the costs.

7 *See* Attachment 3, Declaration of Thomas J. Palmisano for further details regarding decommissioning activities, NRC submittals, and SONGS staffing.

8 *Id.*

9 Public Utilities Code Section 8321 et seq.

10 SCE will seek to recover the severance expenses incurred in decommissioning by other means, if payment from the decommissioning trust would compromise the beneficial tax status of the trusts.

1. Detailed Planning Costs.

The NRC permits the use of up to 3 percent of the estimated decommissioning costs pursuant to 10 CFR 50.75 to fund the initial detailed planning for the radiological decommissioning (or NRC License Termination) at nuclear plant sites. The Master Trusts similarly anticipate the use of 3 percent amount set by Section 50.75 for detailed planning purposes.

As explained in Attachment 3, which provides an overview of the decommissioning process, SCE will need to complete this detailed planning by developing a site-specific decommissioning activities plan that will be described in various submittals to the NRC within the first 24 months following the decision to permanently cease operation. The plans will provide, among other things, a schedule for the completion of decommissioning activities; estimate of the expected costs; environmental assessment; and other related decommissioning topics. The regulatory submittals include:

NEAR TERM REGULATORY SUBMITTALS

- Post-Shutdown Decommissioning Activities Report (PSDAR): *Expected Completion 2Q 2014*
- Irradiated Fuel Management Plan (IFMP): *Expected Completion Prior to the submission of the PSDAR*
- Decommissioning Cost Estimate (DCE): *Expected Completion Prior to the submission of the PSDAR*

SCE expects to complete these initial detailed planning activities within the next year in order to support the filing of an application in 2014 that seeks the Commission's approval of a SONGS 2&3 decommissioning activities plan and cost estimate, and approval of disbursements from the Master Trusts for SONGS decommissioning consistent with that plan and estimate.

2. Used-Fuel Management

There will be a number of near-term used-fuel management activities that require funding from the Master Trusts. Although SONGS is permanently retired, SCE must continue to meet applicable NRC requirements during the decommissioning process prior to license termination. In particular, SCE must continue to maintain the safety and security of used fuel for the radiological health and safety of the public and SCE's employees. The activities will include storing the used fuel in the SONGS 2&3 spent fuel pools, transferring used fuel from the spent fuel pools to casks in the SONGS ISFSI, and continued storage of used fuel in the ISFSI.

SCE will assess the feasibility of accelerating the transfer of used fuel from the spent fuel pools to the ISFSI, and also assess isolating the spent fuel pool cooling systems so that ocean cooling will no longer be required. These activities may decrease overall decommissioning costs. The costs of these activities are not included in this advice letter, and will be identified as fuel storage costs in subsequent advice letters seeking approval of disbursements for future periods, if SCE determines after further study that it is safe and cost-effective to implement these activities.

3. Near-Term Non-Radiological Decommissioning Costs

SCE will also incur non-radiological decommissioning costs related to certain support functions for SONGS decommissioning, such as procurement, finance, human resources (HR), and information technology (IT) activities. The non-radiological decommissioning costs also include costs for insurance, workers compensation, and taxes.

In addition, the largest near-term expense incurred by SCE directly associated with the retirement of SONGS 2&3 are employee-related costs, including labor expenses associated with payments to departing SCE employees at the SONGS site or whose work primarily relates to SONGS 2&3 and assistance with their job searches. SCE has applied to the Internal Revenue Service for a private letter ruling to confirm that disbursements from the decommissioning trust to fund severance would not compromise the trusts' beneficial tax status. As noted above, SCE seeks authority to propose a different means to recover the severance expenses incurred in decommissioning, if payment from the decommissioning trust would compromise the beneficial tax status of the trusts or if another cost-recovery alternative is appropriate.

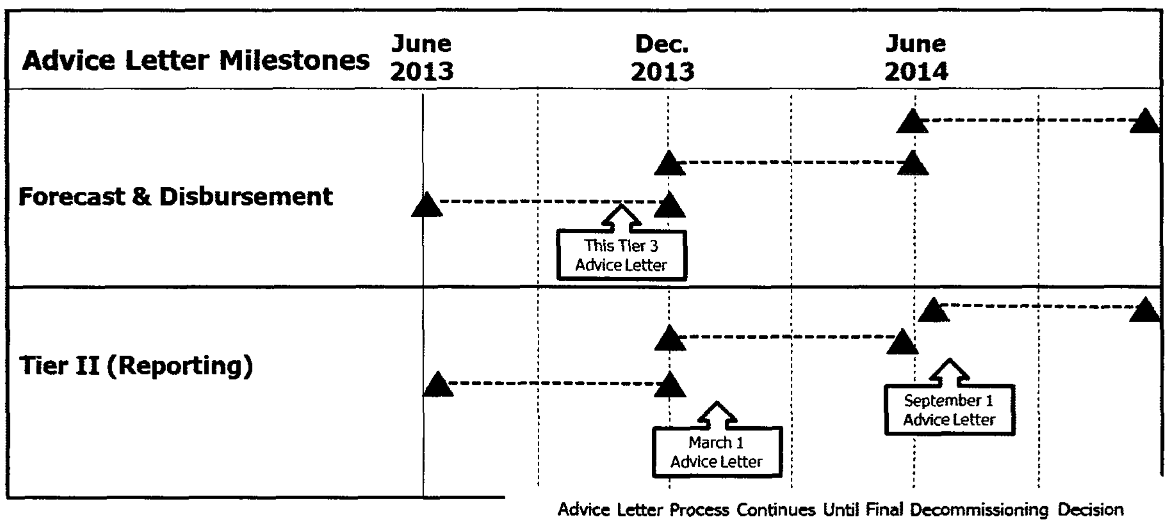
B. Proposed Tier 2 Advice Letter Process

The disbursement approval that SCE seeks in this advice letter will defray SONGS 2&3 decommissioning costs through December 31, 2013. To allow SCE to defray decommissioning costs for subsequent periods, SCE requests that the Commission approve a procedure for SCE to seek disbursements from the Master Trusts for these costs, and for the Commission to review SONGS 2&3 decommissioning activities and costs by means of a Tier 2 advice letter filing.

SCE's proposal is consistent with the Tier 2 advice letter procedure approved by the Commission in D.11-07-003, which established the process for Pacific Gas & Electric's obtaining disbursements from the decommissioning trusts for the Humboldt Bay Power Plant Unit 3 (HBPP). SCE specifically proposes that the Commission approve a process allowing SCE to submit a Tier 2 advice letter in six-month intervals beginning in 2014. The Tier 2 advice letter will provide information regarding the SONGS 2&3 decommissioning activities and costs sufficient for the Commission to (1) identify decommissioning costs incurred in the preceding six-months (i.e. comparing actual recorded costs to SCE's decommissioning budget for the corresponding six-month period), (2) identify the decommissioning budget for the decommissioning costs that will be incurred in the subsequent six-months; and (3) approve disbursements from the Master Trusts for those costs. The figure below depicts the proposed sequence of Tier 2 advice letter submissions for the Commission's review and approval of the SONGS

2&3 decommissioning costs and disbursements from the Master Trusts.[11] SCE will submit testimony on a regular basis to describe the reasonableness of recorded costs in the NDCTP or other proceeding which may be designated by the Commission.

SONGS DECOMMISSIONING



As noted above, SCE proposes this process (i.e., this Tier 3 advice letter and subsequent Tier 2 advice letters) until such time as the Commission has approved SCE's application for approval of SCE's site-specific SONGS 2&3 decommissioning activities plan and detailed cost estimate, and for authority to obtain disbursements from the Master Trusts for SONGS decommissioning costs. SCE anticipates filing this application in 2014 and that it will likely be consolidated in the NDCTP. In the application, SCE will propose to continue the Tier 2 advice letter process for reporting SONGS 2&3 decommissioning activities and costs, similar to the procedure that is being used for HBPP.

C. Designation of Amounts for NRC-Jurisidictional License Termination

The portions of the trust funds for SONGS 2&3 set aside for NRC License Termination should be designated as such based upon an allocation derived from the most recent cost estimate submitted by SCE to the CPUC. As explained below, this will ensure that SCE is able to access the Master Trusts for all intended decommissioning purposes.

11 SCE will provide an 18 month decommissioning cost forecast in a Tier 2 AL until the Commission reviews and approves a site-specific decommissioning plan and detailed cost estimate. Thereafter, SCE will use the Commission-approved cost estimate in the Tier 2 AL to allow the comparison of actual recorded costs to estimated costs.

The NRC has adopted rules in 10 CFR 50.82 that establish restrictions on the use of trust funds designated for NRC License Termination. Specifically, as noted above, NRC's rules initially limit the use of funds to up to 3 percent of NRC generic "formula amount" for decommissioning planning purposes.[12] After submittal of the certifications of permanent cessation of operations and permanent removal of fuel from the reactor vessel, and 90 days after submittal of the PSDAR, a licensee may use an additional 20 percent of the generic decommissioning funding amount.[13] The remaining License Termination funds cannot be used until the site-specific decommissioning cost estimate is submitted to the NRC.

In addition, the NRC has taken the position that, pursuant to 10 CFR 50.82(a)(8)(i)(A), the use of trust funds set aside for License Termination is restricted to "legitimate decommissioning expenses" that fall within the definition of radiological decommissioning in 10 CFR 50.2. In the NRC staff's view, this definition does not include used fuel management or non-radiological site restoration costs.

Nevertheless, NRC has long acknowledged that licensees could accumulate funds for these other purposes in their trust funds commingled with the funds for 10 CFR 50.75 (radiological decommissioning) purposes. For example, in its 1996 rulemaking, the NRC responded to comments on this issue as follows:

> The final rule does not prohibit licensees from having separate subaccounts for other activities in the decommissioning trust fund if minimum amounts specified in the rule are maintained for radiological decommissioning.[14]

The NRC reiterated these principles in the 2002 rulemaking, which bolstered the restrictions on the use of funds in 10 CFR 50.75 trusts, but nevertheless recognized the potential commingling of funds earmarked for non-10 CFR 50.75 purposes. With respect to these funds, the NRC responded to comments as follows:

> As to the statement made by commenters that restrictions should not apply to funds held in trust for purposes other than radiological decommissioning, the Commission's position is that withdrawals for nonradioactive decommissioning expenses that do not affect the amount of funds remaining for radiation decommissioning costs are not covered by this rule. However, the Commission is not proposing that licensees institute separate trusts to account for the different types of activity. The Commission appreciates the benefits that some licensees may derive from their use of a single trust fund for all of their decommissioning costs, both

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[12] 10 CFR 50.82(a)(8)(ii).

[13] *Id.*

[14] Final Rule, Decommissioning of Nuclear Power Reactors, 61 Fed. Reg. 39,278, 39,285 (July 29, 1996).

> radiological and not; but, as stated above, a licensee must be able to identify the individual amounts contained within its single trust.[15]

In more recent years, the NRC in Regulatory Issue Summary (RIS) 2001-07, Rev.1, "10 CFR 50.75 Reporting and Recordkeeping for Decommissioning Planning," dated January 8, 2009 recognized that funds for all decommissioning purposes could be maintained in a single decommissioning trust account, and therefore clarified to licensees that they need to be able to "identify and account for the NRC radiological decommissioning funds" in the account:

> The NRC has not precluded the commingling in a single account of funds accumulated to comply with NRC radiological decommissioning requirements and funds accumulated to address State site restoration costs (State costs) and spent fuel management costs, as long as the licensee is able to identify and account for the NRC radiological decommissioning funds that are contained within its single account.

Duke Energy Florida, Inc. (DEF) recently addressed a similar situation in which it had commingled trust funds for License Termination, Spent Fuel Management, and Site Restoration, but had not designated specific amounts within the trusts for these purposes. In response to a Petition for Declaratory Relief filed by DEF, the Florida Public Service Commission recently issued an Order agreeing that the amounts for each category should be designated based upon the most recent site specific decommissioning cost estimate.[16]

In order to clearly identify the portions of the trust funds for SONGS 2&3 set aside for NRC License Termination consistent with the NRC's guidance discussed above, SCE requests that the Commission designate the amounts set aside for this purpose based upon an allocation derived from the most recent ABZ cost estimate submitted by SCE to the Commission, as follows:

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[15] Final Rule, Decommissioning Trust Provisions, 67 Fed. Reg. 78,332, 78,340 (Dec. 24, 2002) (emphasis added).

[16] "Order Granting, In Part, and Denying, In Part, Petition for Declaratory Relief," Dkt. No. 130207-EI, Order No. PSC-13-0452-FOF-EI, Slip Op. at 8 (October 9, 2013) ("The funds accumulated in the DEF Nuclear Decommissioning Trust Fund shall be allocated among NRC License Termination, Spent Fuel Management, and Site Restoration pursuant to, and in accordance with the percentage assigned to each category in the most current Nuclear Decommissioning Study, or update thereto, filed with and approved by us pursuant to Rule 25-6.04365, F.A.C."). Notably, the Florida Public Service Commission declined to rule that the funds designated for spent fuel management or site restoration could not be used for license termination purposes, if needed.

Table 1
Designation of Decommissioning Costs by ABZ Category
(SCE Share)[17]
$ in Millions, 2013$

		Latest NDCTP Estimate 100% Level	SCE Share*	Calculated Value	Breakdown of Trust Fund** Using Calculated Value
SONGS 2			75.7363%		
	License Termination	849,547	643,415	43%	567,132
	Site Restoration	436,725	330,759	22%	291,544
	Fuel Storage	686,292	519,772	35%	458,148
	Total	1,972,564	1,493,947	100%	1,316,824
SONGS 3			75.7475%		
	License Termination	829,091	628,016	38%	569,761
	Site Restoration	606,393	459,328	28%	416,720
	Fuel Storage	724,291	548,632	34%	497,741
	Total	2,159,775	1,635,976	100%	1,484,221
Grand Total		4,132,339	3,129,923		2,801,045

* Share as of shutdown
** 7/31/2013 Trust Balances

Based upon this allocation, SCE requests that the Commission designate $567.132 million for SONGS 2 and $569.761 million for SONGS 3 as the NRC License Termination amount as of July 31, 2013 for the respective units. The remaining amounts in Master Trusts would not be subject to the NRC restrictions applicable to the NRC License Termination amounts, and would, therefore allow SCE to use the remaining amounts for their intended purposes (including site restoration and used fuel management) without restriction by the NRC.

D. Balancing Account and Proposed Tariff Change

This advice filing does not increase any rate or charge, cause the withdrawal of service, or conflict with any other schedule or rule. However, SCE requests authority to establish Preliminary Statement, Part GG, SONGS Operations and Maintenance Balancing Account (SOMBA), a two-way balancing account, which will be used to track SONGS O&M expense that cannot be funded from the decommissioning trusts. At the end of each month or as soon as possible thereafter, SCE will examine its recorded

[17] As identified in this Tier 3 advice letter for costs through December 31, 2014, the costs for detailed planning and preparing NRC submittals is a component of License Termination costs; the costs for used-fuel management activities is a component of Fuel Storage costs; and the costs for non-radiological decommissioning activities is a component of Site-Restoration costs.

expenses and first determine if the recorded expenses can be defrayed by disbursements from the decommissioning trusts. After first making such a determination, SCE would then record any remaining SONGS O&M expenses in the balancing account. At the end of each year, the difference between authorized SONGS O&M expense and the recorded amount (over-collection) would be transferred from SOMBA and credited to SCE's Energy Resource Recovery Account (ERRA) balancing account to help mitigate fuel and purchased power (i.e., ERRA) under-collections. If the recorded O&M amount exceeds the authorized amount, SCE would transfer the under-collection from SOMBA and debit SCE's Base Revenue Requirement Balancing Account (BRRBA) for recovery in rates. As such, Preliminary Statements Part YY, BRRBA and Part ZZ, ERRA are revised accordingly herein. At this time, SCE proposes to only recover the recorded SONGS O&M expenses from current SCE customers to the extent that such expenses are not eligible to be recovered from the decommissioning trusts. The SOMBA will be an interest-bearing balancing account.

IV. REQUEST FOR RELIEF

For the reasons explained above, SCE requests that the Commission issue a resolution that:

1. Authorizes SCE to obtain interim disbursements of up to $214 million (SCE Share) from the Master Trusts SONGS 2&3 for SONGS 2&3 decommissioning expenses incurred in 2013;

2. Approves a Tier 2 advice letter procedure, consistent with the process established in Decision (D.) 11-07-003, for (1) SCE to seek disbursements for decommissioning costs incurred in 2014 and future periods until adoption of a final SONGS 2&3 decommissioning activities plan and cost estimate by the Commission, and (2) the Commission to review SONGS 2&3 decommissioning activities and recorded costs;

3. Designates which portions of the trust funds for SONGS 2&3 that should be set aside for NRC License Termination. The amounts the Commission should designate as allocated to NRC License Termination are $567.132 million for SONGS 2 and $569.761 million for SONGS 3;

4. Authorizes SCE to establish a SOMBA to record the difference between actual SONGS 2&3 O&M expenses, trust fund disbursements, and the authorized SONGS 2&3 O&M expenses included in customer rates.

V. OTHER INFORMATION

TIER DESIGNATION

Pursuant to General Order (GO) 96-B, Energy Industry Rule 5.3, this advice letter is submitted with a Tier 3 designation.

EFFECTIVE DATE

This advice filing will become effective upon Commission approval.

NOTICE

Anyone wishing to protest this advice letter may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice letter. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Leslie E. Starck
Senior Vice President, Regulatory Policy & Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

In accordance with Section 4 of GO 96-B, SCE is serving copies of this advice filing to the interested parties shown on the attached GO 96-B, A.12-12-013, and I.12-10-013 service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-2930. For changes to all other service lists, please contact the CPUC's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the CPUC, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Doug Snow at (626) 302-2035 or by electronic mail at Douglas.Snow@sce.com

Southern California Edison Company

/s/ Megan Scott-Kakures
Megan Scott-Kakures

MSK:wam:dm
Enclosures

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:
☑ ELC ☐ GAS
☐ PLC ☐ HEAT ☐ WATER

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: Darrah.Morgan@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas
PLC = Pipeline HEAT = Heat WATER = Water

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: 2968-E Tier Designation: 3

Subject of AL: Request for (1) Authorization of Disbursements from the Master Trusts for San Onofre Nuclear Generating Station; (2) Approval of Tier 2 Advice Letter Process for Future Disbursements; (3) Designation of Trust Amounts Set Aside for NRC License Termination; and (4) Approval of Balancing Account

Keywords (choose from CPUC listing): San Onofre Nuclear Generating Station, Nuclear, Balancing Account

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☐ One-Time ☑ Other See Advice Letter

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL[1]:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution Required? ☑ Yes ☐ No

Requested effective date: Upon Approval No. of tariff sheets: 6

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: Preliminary Statements and Table of Contents

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: Advice 2948-E

[1] Discuss in AL if more space is needed.

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Megan Scott-Kakures
Vice President, Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Facsimile: (626) 302-4829
E-mail: AdviceTariffManager@sce.com

Leslie E. Starck
Senior Vice President, Regulatory Policy & Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

Cal. P.U.C. Sheet No.	Title of Sheet	Cancelling Cal. P.U.C. Sheet No.
Original 53384-E	Preliminary Statement Part GG	
Revised 53385-E	Preliminary Statement Part YY	Revised 53202-E
Revised 53386-E	Preliminary Statement Part ZZ	Revised 51647-E
Revised 53387-E	Table of Contents	Revised 53244-E
Revised 53388-E	Table of Contents	Revised 52937-E
Revised 53389-E	Table of Contents	Revised 53189-E

GG. SONGS Operations and Maintenance Balancing Account (SOMBA)

1. Purpose:

The purpose of the San Onofre Nuclear Generating Station (SONGS) Operations and Maintenance (O&M) Balancing Account (SOMBA) is to track the difference between: (1) actual SONGS Units 2 and 3 (SONGS 2&3) O&M expenses; (2) disbursements from Southern California Edison Company's Nuclear Facilities Qualified and Non-qualified CPUC Decommissioning Master Trusts for SONGS; and, (3) authorized SONGS O&M included in base rates.

2. Definitions:

a. SONGS Authorized O&M

The amounts authorized in SCE's 2012 GRC for O&M expenses associated with "normal" operations. The costs are associated with day-to-day activities including the following organizations at SONGS: engineering, operations and maintenance, radiation chemical control, regulatory, security and training.

b. Interest Rate

The Interest Rate shall be one-twelfth of the Federal Reserve three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15 (expressed as an annual rate). If in any month a non-financial rate is not published, SCE shall use the Federal Reserve three-month Commercial Paper Rate – Financial.

3. Operations of the SOMBA

a. Entries in the SOMBA shall be made on a monthly basis as follows:

1. Debit entry equal to recorded SONGS 2&3 O&M expenses;
2. Less: credit entry equal to amounts that can be reimbursed from the decommissioning trusts;
3. Less: credit entry equal to authorized SONGS 2&3 O&M expenses;
4. Equals: the annual (Over)/Under Collection.

4. Disposition

SCE will transfer the December 31st balance of the SOMBA to either:

a. SCE's ERRA balancing account - if the balance is an annual over-collection to help mitigate fuel and purchased power (i.e. ERRA) under-collections; or

b. SCE's Base Revenue Requirement Balancing Account (BRRBA) Generation Subaccount - if the balance is an annual under-collection.

5. Review Procedures

Reasonableness of recorded operation of the SOMBA shall be reviewed by the Commission in SCE's annual April ERRA Review proceeding.

YY. Base Revenue Requirement Balancing Account (BRRBA) (Continued)

5. Generation Sub-account:

(P)

(12) Entry to annually record the transfer of the December 31st balance in the Post-Employment Benefits Other Than Pensions (PBOP).

(13) Credit entry to annually record the transfer of the December 31st balance in the Results Sharing Memorandum Account.

(14) Entry to annually record the transfer of the December 31st balance in the Medical Programs Balancing Account.

(15) Entry to annually record the transfer of the December 31st balance in the Mohave Balancing Account.

(16) Entry to annually record the transfer of the December 31st balance in the Four Corners Memorandum Account.

(17) Debit or credit entry to record the monthly transfer of the balance in the Fuel Cell Program Memorandum Account. (P) (P)

(18) An entry to record other Generation-related amounts as authorized by the Commission. (P)

(19) Entry to annually record the transfer of the December 31st balance in the SONGS Operations and Maintenance Balancing Account, if undercollected. (N) | (N)

The sum of (1) through (19) equals the activity recorded in the Generation Sub-account of the BRRBA. (T)(P)

Interest Expense shall be calculated monthly by applying the Interest Rate to the average balance of the beginning-of-month and the end-of-month balances in the Generation Sub-account.

6. SONGS 2&3 Refueling and Maintenance Outage Tracking Account

The SONGS 2&3 Refueling and Maintenance Outage Tracking Account (SONGS 2&3 RMOTA) shall track for each calendar year in the GRC cycle the revenue requirement difference between: 1) the actual number of SONGS 2&3 refueling and maintenance outages; and 2) the number of SONGS 2&3 refueling and maintenance outages included in SCE's authorized generation revenue requirement. The account shall not track SONGS 2&3 unplanned outages.

SONGS 2&3 refueling and maintenance outage expenses to be included in SCE's authorized generation revenue requirements (as identified in section 2.b.) shall be determined using the second quarter Global Insight escalation factors.

ZZ. ENERGY RESOURCE RECOVERY ACCOUNT (Continued)

3. Operation of the ERRA (Continued):

Entries to the ERRA shall be made on a monthly basis as follows: (Continued)

p. Debit or credit entries equal to recorded Mountainview-related costs including:
   i. Availability incentives;
   ii. Heat Rate Incentives;
   iii. Amortization of emission credits; and
   iv. Gain or loss on sales of emission credits;

q. A debit entry equal to recorded 20/20 Rebate Program Costs including:
   i. 20/20 Rebate amount included on customers' bills increased for FF&U
   ii. Incremental O&M Costs incurred to implement the Summer 2004 and 2005 20/20 programs.

r. A credit entry equal to the payment made by a CCA to compensate SCE for incremental purchased power costs as the result of the CCA causing a delay in the "CCA cut-over date" pursuant to D.05-12-041.

s. Transfers, up to a maximum of 10 million, to the Energy Assistance Fund Tracking Account Associated with the Energy Assistance Fund Rate Relief Program.

t. A debit entry equal to recorded independent evaluator costs.

u. A debit entry equal to the fees associated with participation in Western Renewable Energy Generation Information System.

v. A credit entry equal to the proceeds received (net of book cost) from the sale of sulfur dioxide (SO_2) credits.

w. A debit entry equal to the cost associated with the purchase of sulfur dioxide (SO_2) allowances.

x. A debit equal to costs related to congestion charges and CRRs.

y. A credit equal to congestion revenue and CRRs.

z. A debit equal to costs associated with CAISO convergence bidding.

aa. A credit equal to CAISO convergence bidding revenues.

bb. A debit entry equal to costs related to Tradable Renewable Energy credits (TRECS).

cc. A credit entry equal to the proceeds of the sale of TRECS.

dd. A debit entry equal to power purchase payments provided to eligible Net Energy Metering customers for energy produced by on-site generation in excess of consumption over a 12-month period. Power purchase payments may include additional compensation for renewable attributes where applicable.

ee. A debit entry equal to costs incurred for the greenhouse gas compliance instrument transactions pursuant to D.12-04-046.

ff. A credit entry equal to one-twelfth of the authorized forecasted direct and indirect GHG costs, deferred for future recovery in rates.

gg. A debit entry equal to the balance in the GHG subaccount included for recovery in rates.

hh. A credit entry annually to record the transfer of the December 31st balance in the SONGS Operations and Maintenance Balancing Account, if overcollected. (N) (N)

The sum of (a) through (hh) equals the activity recorded in the ERRA each month. (T)

Interest shall accrue monthly to the ERRA by applying the Interest Rate to the average of the beginning and ending monthly ERRA balances.

TABLE OF CONTENTS

Sheet 1

Cal. P.U.C.
Sheet No.

PRELIMINARY STATEMENT:

(Continued)

TABLE OF CONTENTS Sheet 2

(Continued)

Cal. P.U.C. Sheet No.

PRELIMINARY STATEMENT: (Continued)

(Continued)

TABLE OF CONTENTS

Sheet 3

(Continued)

Cal. P.U.C. Sheet No.

PRELIMINARY STATEMENT: (Continued)

(Continued)

ATTACHMENT 1

Southern California Edison
SONGS Decommissioning
Monthly Summary Of Advice Letter (June 8, 2013 - December 31, 2014)
(Nominal Dollars In Thousands, 100% Share)

	2013							2014												
	RECORDED [1]				FORECAST [2]			FORECAST [3]												
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Base O&M																				
Labor	$ 10,570	$ 14,899	$ 12,274	$ 7,901	$ 5,586	$ 5,586	$ 5,586	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 6,191	$ 4,337	$ 4,337	$ 4,337	$ 4,337	$ 4,337	$ 4,337	$ 125,564
Payroll Adders	2,922	4,120	3,410	2,210	1,728	1,728	1,728	1,789	1,789	1,789	1,789	1,789	1,789	1,289	1,289	1,289	1,289	1,289	1,289	36,314
Non-Labor Variable [4]	2,596	4,435	2,506	2,771	9,242	9,242	9,242	4,502	4,502	4,502	3,919	3,919	3,919	3,586	3,586	3,586	3,586	3,586	3,586	86,815
Non-Labor Fixed	159	2,896	502	(221)	1,649	1,649	1,649	1,437	1,437	1,437	599	599	599	1,107	1,107	1,107	929	929	929	20,501
Decommissioning Planning	160	281	442	237	1,292	1,292	1,292	727	727	727	727	727	727	727	727	727	727	727	727	13,717
Non-SONGS SCE Labor	206	298	310	257	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	5,471
Non-SONGS SCE Non-Labor	169	220	203	1,141	362	362	362	355	355	355	355	355	355	355	355	355	355	355	355	7,072
Subtotal Base O&M	**$ 16,782**	**$ 27,148**	**$ 19,646**	**$ 14,295**	**$ 20,151**	**$ 20,151**	**$ 20,151**	**$ 15,294**	**$ 15,294**	**$ 15,294**	**$ 13,873**	**$ 13,873**	**$ 13,873**	**$ 11,694**	**$ 11,694**	**$ 11,694**	**$ 11,516**	**$ 11,516**	**$ 11,516**	**$ 295,454**
Average Monthly Headcount [5]	1,483	1,472	1,021	571	571	571	571	571	571	571	571	571	571	400	400	400	400	400	400	
Capital Expenditures																				
Non-ISFSI CapEx	$ 711	$ 705	$ 58	$ 213	$ 3,543	$ 3,543	$ 3,543	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 569	$ 19,141
ISFSI CapEx [6]	156	244	306	2,712	662	662	662	676	676	676	676	676	676	676	676	676	676	676	676	13,517
CapEx Allowances	-	-	-	-	1,000	1,000	1,000	188	188	188	188	188	188	188	188	188	188	188	188	5,250
Subtotal CapEx	**$ 867**	**$ 949**	**$ 364**	**$ 2,925**	**$ 5,205**	**$ 5,205**	**$ 5,205**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 1,432**	**$ 37,907**
Other Costs																				
Workmans Comp	$ 60	$ 110	$ 155	$ 69	$ 96	$ 96	$ 96	$ 99	$ 99	$ 99	$ 99	$ 99	$ 99	$ 72	$ 72	$ 72	$ 72	$ 72	$ 72	$ 1,708
P&L Insurance	597	77	851	796	864	864	864	880	880	880	880	880	880	880	880	880	880	880	880	15,476
ITAS	386	471	367	308	266	266	266	266	266	266	266	266	266	266	266	266	266	266	266	5,423
A&G [7]	418	650	3,334	429	659	659	659	394	394	394	357	357	357	855	312	312	307	307	307	11,460
Severance: [8]																				
SONGS Severance	-	-	83,676	-	-	-	-	-	-	-	-	-	-	15,898	-	-	-	-	-	99,574
Non-SONGS Severance	-	-	24,176	-	-	-	-	-	-	-	-	-	-	4,593	-	-	-	-	-	28,769
Subtotal Severance	$ -	$ -	$ 107,852	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,492	$ -	$ -	$ -	$ -	$ -	$ 128,343
Subtotal Other Costs	**$ 1,462**	**$ 1,208**	**$ 112,559**	**$ 1,602**	**$ 1,885**	**$ 1,885**	**$ 1,885**	**$ 1,640**	**$ 1,640**	**$ 1,640**	**$ 1,603**	**$ 1,603**	**$ 1,603**	**$ 22,564**	**$ 1,529**	**$ 1,529**	**$ 1,525**	**$ 1,525**	**$ 1,525**	**$ 162,410**
Total SONGS Costs (100% Share)	**$ 19,110**	**$ 29,305**	**$ 132,569**	**$ 18,823**	**$ 27,241**	**$ 27,241**	**$ 27,241**	**$ 18,366**	**$ 18,366**	**$ 18,366**	**$ 16,908**	**$ 16,908**	**$ 16,908**	**$ 35,690**	**$ 14,656**	**$ 14,656**	**$ 14,473**	**$ 14,473**	**$ 14,473**	**$ 495,772**
Cumulative Total (100% Share)	$ 19,110	$ 48,416	$ 180,985	$ 199,808	$ 227,049	$ 254,289	$ 281,530	$ 299,896	$ 318,263	$ 336,629	$ 353,537	$ 370,444	$ 387,352	$ 423,043	$ 437,698	$ 452,354	$ 466,826	$ 481,299	$ 495,772	
Cumulative Total (SCE Share) [9]	$ 14,524	$ 36,796	$ 137,549	$ 151,854	$ 172,557	$ 193,260	$ 213,963	$ 227,921	$ 241,880	$ 255,838	$ 268,688	$ 281,538	$ 294,388	$ 321,512	$ 332,651	$ 343,789	$ 354,788	$ 365,787	$ 376,787	

Notes:
(1) Incurred costs post shutdown (i.e., June 8, 2013 - September 30, 2013). For purposes of this analysis, 3/4 of the costs incurred in June 2013 were assumed to be incurred post-shutdown
(2) The Base O&M forecast reflects the current estimate to complete for the remainder of 2013. Capital expenditures and other costs have been forecasted separately
(3) The Base O&M forecast reflects the current 2014 SONGS O&M budget request. Capital expenditures and other costs have been forecasted separately. 2014 costs may increase due to accelerating certain activities that may ultimately decrease the total cost of decommissioning, such as accelerating removal of fuel from the spent fuel pool. SCE is currently evaluating whether and to what extent to accelerate these activities, and will update its estimate of 2014 costs as appropriate in subsequent filings seeking approval of disbursements for future periods.
(4) Non-Labor Variable includes approximately $22,550,000 in 2014 associated with the Radioactive Waste Shipment project
(5) Actual headcount will vary slightly from month to month
(6) Beginning in October 2013, ISFSI Capital is based on ABZ's Early Decommissioning Cost Estimate (2015)
(7) A&G is calculated at 2.65% of total costs excluding payroll adders and is not a recorded cost.
(8) The severance costs shown are the estimate of total severance costs related to the headcount reductions in August 2013 and July 2014 and are not based on recorded costs
(9) SCE's share of decommissioning costs is based upon SCE's having an approximately 76% share of the costs. The SONGS participants' respective share of the decommissioning costs is governed by Section 22 of the Second Amended Operating Agreement for SONGS, with the city of Anaheim's share of decommissioning costs also being governed by the Settlement Agreement Relating to SONGS by and between SCE and the City of Anaheim, dated December 20, 2005.

Attachment 1

Southern California Edison
SONGS Decommissioning
Advice Letter - Description Of Cost Categories

Cost Category	Description
Base O&M	
Labor	Labor costs associated with SCE SONGS site personnel.
Payroll Adders	Costs associated with payroll taxes and employee benefits such as health care, dental/vision, pensions, corporate incentive program for SCE SONGS site personnel, and short and long-term disability insurance.
Non-Labor Variable	All other costs that are not classified as fixed costs such as material, contractor support, and expenses.
Non-Labor Fixed	Costs including NRC Fees and other contractually obligated or required regulatory costs (e.g., EPA, Marine & Coastal Fees, water utilities, etc.). Also includes the site leases and easements, and various memberships in industry working groups.
Decommissioning Planning	Non-Labor portion of decommissioning planning activities (e.g., contractor and material costs). SCE Labor portion of decommissioning planning activities are captured in the Labor costs associated with SONGS personnel.
Non-SONGS SCE Labor	Labor costs associated with SCE employees who directly support SONGS (i.e., Transportation, Information Technology and Business & Financial Services), but are not included in the SONGS site headcount and budget.
Non-SONGS SCE Non-Labor	Non-Labor costs associated with services to SONGS associated with other SCE organizational units that are charged to SONGS through Indirect Market Mechanisms.
Capital Expenditures	
Non-ISFSI CapEx	All capital expenditures, excluding ISFSI capital expenditures, necessary for security and regulatory-related projects necessary to fulfill NRC requirements as well as costs associated with closing out projects reduced in scope as a result of the decision to retire SONGS.
ISFSI CapEx	Capital expenditures related to dry fuel storage.
CapEx Allowances	Capital expenditure allowances for potential projects. Includes allowances for Mesa shutdown and changes to the Emergency Response ePlan and Security Plan.
Other Costs	
Workmans Comp	Workman's compensation costs for SONGS employees.
P&L Insurance	Songs related Nuclear and non-Nuclear Property & Liability insurance. Also includes excess Workman's Comp insurance.
ITAS	Portion of corporate level cost assigned to SONGS for Information Technology and Services.
A&G	Administrative and General costs of SCE related to SONGS.
SONGS Severance	Severance related to reduction of SONGS site personnel as a result of SONGS shutdown. It does not include any severance related to the Business Transformation headcount reductions made earlier in 2013.
Non-SONGS Severance	Severance directly related to the shutdown of SONGS for SCE employees not included in the SONGS site headcount. For example, Human Resources, Procurement, and Financial Services all reduced headcount as a result of the SONGS shutdown, but are not included in the SONGS headcount.

ATTACHMENT 2

Southern California Edison
SONGS Decommissioning
Comparison Of Advice Letter And ABZ's Early Decommissioning Cost Estimate (2015)
(Nominal Dollars In Thousands, 100% Share)

	Decommissioning Cash Plan						
	2013		2014				
	3Q 2013 [1]	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014	Total
Base O&M							
Labor	$ 45,643	$ 16,757	$ 18,572	$ 18,572	$ 13,010	$ 13,010	$ 125,564
Payroll Adders	12,662	5,184	5,368	5,368	3,866	3,866	36,314
Non-Labor Variable	12,308	27,726	13,506	11,757	10,759	10,759	86,815
Non-Labor Fixed	3,336	4,947	4,312	1,798	3,322	2,788	20,501
Decommissioning Planning	1,121	3,875	2,180	2,180	2,180	2,180	13,717
Non-SONGS SCE Labor	1,070	880	880	880	880	880	5,471
Non-SONGS SCE Non-Labor	1,733	1,085	1,064	1,064	1,064	1,064	7,072
Subtotal Base O&M	**$ 77,872**	**$ 60,454**	**$ 45,882**	**$ 41,619**	**$ 35,081**	**$ 34,547**	**$ 295,454**
Capital Expenditures							
Non-ISFSI CapEx	$ 1,687	$ 10,629	$ 1,706	$ 1,706	$ 1,706	$ 1,706	$ 19,141
ISFSI CapEx	3,419	1,985	2,028	2,028	2,028	2,028	13,517
CapEx Allowances	-	3,000	563	563	563	563	5,250
Subtotal CapEx	**$ 5,105**	**$ 15,614**	**$ 4,297**	**$ 4,297**	**$ 4,297**	**$ 4,297**	**$ 37,907**
Other Costs							
Workmans Comp	$ 394	$ 288	$ 298	$ 298	$ 215	$ 215	$ 1,708
P&L Insurance	2,321	2,592	2,641	2,641	2,641	2,641	15,476
ITAS	1,432	798	798	798	798	798	5,423
A&G [2]	4,831	1,976	1,183	1,071	1,478	921	11,460
Severance							
SONGS Severance	83,676	-	-	-	15,898	-	99,574
Non-SONGS Severance	24,176	-	-	-	4,593	-	28,769
Subtotal Severance	$ 107,852	$ -	$ -	$ -	$ 20,492	$ -	$ 128,343
Subtotal Other Costs	**$ 116,831**	**$ 5,654**	**$ 4,921**	**$ 4,808**	**$ 25,623**	**$ 4,574**	**$ 162,410**
Total SONGS Costs	**$ 199,808**	**$ 81,722**	**$ 55,099**	**$ 50,723**	**$ 65,002**	**$ 43,418**	**$ 495,772**

	ABZ Estimate						
	2013		2014				
	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014	Total
Base O&M							
Labor	$ 38,786	$ 30,711	$ 34,862	$ 33,215	$ 49,653	$ 49,912	$ 237,138
Payroll Adders	-	-	-	-	-	-	-
Non-Labor Variable	5,267	5,267	9,024	9,759	9,292	10,130	48,738
Non-Labor Fixed	1,450	1,450	1,482	1,482	1,482	1,482	8,828
Decommissioning Planning	-	-	-	-	-	-	-
Non-SONGS SCE Labor	-	-	-	-	-	-	-
Non-SONGS SCE Non-Labor	-	-	-	-	-	-	-
Subtotal Base O&M	**$ 45,503**	**$ 37,428**	**$ 45,367**	**$ 44,455**	**$ 60,427**	**$ 61,523**	**$ 294,704**
Capital Expenditures							
Non-ISFSI CapEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ISFSI CapEx	1,985	1,985	2,028	2,028	2,028	2,028	12,083
CapEx Allowances	-	-	-	-	-	-	-
Subtotal CapEx	**$ 1,985**	**$ 1,985**	**$ 2,028**	**$ 2,028**	**$ 2,028**	**$ 2,028**	**$ 12,083**
Other Costs							
Workmans Comp	$ 369	$ 369	$ 377	$ 377	$ 377	$ 377	$ 2,245
P&L Insurance	190	190	194	194	194	194	1,156
ITAS	-	-	-	-	-	-	-
A&G [2]	-	-	-	-	-	-	-
Severance							
SONGS Severance	115,142	-	-	-	22,220	-	137,361
Non-SONGS Severance	-	-	-	-	-	-	-
Subtotal Severance	$ 115,142	$ -	$ -	$ -	$ 22,220	$ -	$ 137,361
Subtotal Other Costs	**$ 115,700**	**$ 559**	**$ 571**	**$ 571**	**$ 22,790**	**$ 571**	**$ 140,762**
Total SONGS Costs	**$ 163,189**	**$ 39,972**	**$ 47,966**	**$ 47,054**	**$ 85,246**	**$ 64,122**	**$ 447,549**

	Variance						
	2013		2014				
	3Q 2013	4Q 2013	1Q 2014	2Q 2014	3Q 2014	4Q 2014	Total
Base O&M							
Labor	$ 6,857	$ (13,954)	$ (16,290)	$ (14,643)	$ (36,643)	$ (36,902)	$ (111,575)
Payroll Adders	12,662	5,184	5,368	5,368	3,866	3,866	36,314
Non-Labor Variable	7,041	22,460	4,482	1,998	1,467	629	38,076
Non-Labor Fixed	1,886	3,496	2,830	316	1,840	1,306	11,674
Decommissioning Planning	1,121	3,875	2,180	2,180	2,180	2,180	13,717
Non-SONGS SCE Labor	1,070	880	880	880	880	880	5,471
Non-SONGS SCE Non-Labor	1,733	1,085	1,064	1,064	1,064	1,064	7,072
Subtotal Base O&M	**$ 32,369**	**$ 23,026**	**$ 514**	**$ (2,836)**	**$ (25,346)**	**$ (26,976)**	**$ 750**
Capital Expenditures							
Non-ISFSI CapEx	$ 1,687	$ 10,629	$ 1,706	$ 1,706	$ 1,706	$ 1,706	$ 19,141
ISFSI CapEx	1,433	-	-	-	-	-	1,433
CapEx Allowances	-	3,000	563	563	563	563	5,250
Subtotal CapEx	**$ 3,120**	**$ 13,629**	**$ 2,269**	**$ 2,269**	**$ 2,269**	**$ 2,269**	**$ 25,824**
Other Costs							
Workmans Comp	$ 25	$ (81)	$ (78)	$ (78)	$ (161)	$ (161)	$ (533)
P&L Insurance	2,131	2,402	2,447	2,447	2,447	2,447	14,320
ITAS	1,432	798	798	798	798	798	5,423
A&G [2]	4,831	1,976	1,183	1,071	1,478	921	11,460
Severance							
SONGS Severance	(31,465)	-	-	-	(6,321)	-	(37,787)
Non-SONGS Severance	24,176	-	-	-	4,593	-	28,769
Subtotal Severance	$ (7,290)	$ -	$ -	$ -	$ (1,728)	$ -	$ (9,018)
Subtotal Other Costs	**$ 1,131**	**$ 5,095**	**$ 4,350**	**$ 4,237**	**$ 2,834**	**$ 4,004**	**$ 21,652**
Total SONGS Costs	**$ 36,620**	**$ 41,750**	**$ 7,133**	**$ 3,670**	**$ (20,243)**	**$ (20,703)**	**$ 48,226**

Notes:
(1) Third quarter 2013 also includes the costs incurred post-shutdown in June.
(2) ABZ staff rates include a 5% corporate overhead, which is included in ABZ's Labor line item in this schedule.

Attachment 2

ATTACHMENT 3

DECLARATION OF THOMAS J. PALMISANO REGARDING INITIAL DECOMMISSIONING ACTIVITIES

I, Thomas J. Palmisano, declare and state:

1. I am Vice President, Nuclear Engineering for Southern California Edison Company (SCE) at the San Onofre Nuclear Generating Station (SONGS). In that capacity, I am responsible for and involved in SCE's initial decommissioning planning activities for SONGS, including the preparation of a site-specific decommissioning plan and cost estimate. I have personal knowledge of the facts and representations herein and, if called upon to testify, could and would do so, except for those facts expressly stated to be based upon information and belief, and as to those matters, I believe them to be true.

2. The purpose of this declaration is to provide an overview of the decommissioning process and SCE's initial decommissioning planning activities, in support of SCE's Tier 3 advice letter submitted to the California Public Utilities Commission (Commission or CPUC).

I. Methods and Phases of Decommissioning

3. NRC Regulatory Guide 1.184, "Decommissioning of Nuclear Power Reactors," describes methods and procedures acceptable to the NRC for implementing the NRC regulatory requirements of decommissioning. The regulatory guide goes through the regulatory process that a licensee must follow to decommission a nuclear power plant, and provides guidance for completing these regulatory activities. As defined by 10 CRF 50.2, "decommission" means to remove a nuclear facility from service and reduce residual radioactivity to a level that permits (1) release of the property for unrestricted use and termination of the license, or (2) release of the property under restricted conditions and termination of the NRC license. In particular, NRC regulations identify three methods acceptable for decommissioning: (1) DECON; (2) SAFSTOR; and (3) ENTOMB.

4. For DECON, the equipment, structures, and portions of the facility and site that contain radioactive contaminants are removed or decontaminated to a level that permits termination of the license after cessation of operations.

5. SAFSTOR involves placing the facility in a safe stable condition and maintained in that state until it is subsequently decontaminated and dismantled to levels that permit license termination. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the levels of radioactivity in and on the material and potentially the quantity of material that must be disposed of during decontamination and dismantlement (D&D).

6. ENTOMB involves encasing radioactive structures, systems, and components in concrete or similarly long-lasting material. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license. SCE will not use the ENTOMB decommissioning method for SONGS.

7. NRC regulations provide that the three decommissioning methods may be combined. As further discussed in this declaration, SCE will be developing a site-specific plan that may combine DECON and SAFSTOR decommissioning methods.

8. Regulatory Guide 1.184 further describes three broad phases for the decommission process. Phase 1 of decommissioning "includes the initial activities, starting on the effective date of permanent cessation of operations..."; this phase is approximately 2 years in duration. Phase 2 "encompasses activities during the storage period or during major decommissioning activities..."; this phase is variable in length but up to 50 or more years after cessation of operation. Phase 3 "consists of the rest of the activities that the licensee undertakes to terminate the license"; this phase must be complete within 60 years of ceasing operation.

9. SCE's request for CPUC approval of disbursements from the Master Trusts are for decommissioning costs generally incurred in Phase 1.

II. Key Regulatory Submittals

10. SCE is required to submit a number of written certifications, reports, and plans in connection with the decommissioning activities for SONGS. The key regulatory submittals include: (1) Certification of Permanent Cessation of Operation; (2) Certification of Permanent Removal of Fuel; (3) Irradiated Fuel Management Plan; (4) a site-specific Decommissioning Cost Estimate (DCE); (5) Post Shutdown Decommissioning Activities Report (PSDAR); and (6) License Termination Plan (LTP). I will describe these key submittals in further detail below.

11. **Certification of Permanent Cessation of Operation**: Pursuant to 10 CFR 50.82(a)(1)(i), when a licensee has decided to permanently cease operations, the licensee must submit a Certification of Permanent Cessation of Operation to the NRC within 30 days of that decision, consistent with the requirements provided in 10 CFR 50.4(b)(8). SCE submitted this certification on June 12, 2013.

12. **Certification of Permanent Removal of Fuel**: Once a licensee has permanently removed the fuel from the reactor vessel, 10 CFR 50.82(a)(1)(ii) requires the licensee to submit a Certification of Permanent Removal of Fuel to the NRC consistent with the requirements provided in 10 CFR 50.4(b)(9), stating the date the fuel was permanently removed from the reactor vessel and the disposition of the fuel. SCE submitted the certification for Unit 3 on June 28, 2013, and for Unit 2 on July 23, 2013.

13. **Decommissioning Cost Estimate**: Pursuant to 10 CFR 50.82(a)(8)(iii & iv), "within 2 years following permanent cessation of operations, if not already submitted, the licensee shall submit a site specific decommissioning cost estimate... the licensee shall provide a means of adjusting cost estimated and associated funding levels over the storage or surveillance period." Accordingly, SCE must prepare a site-specific DCE for SONGS, to reflect the permanent retirement date of June 7, 2013 and the methods selected for decommissioning, and delineate the methods of adjusting costs through the decommissioning periods. The DCE is prepared and issued in Phase 1 of the decommissioning process.

14. **Irradiated Fuel Management Plan**: Pursuant to 10 CFR 50.54(bb), SCE must submit to the NRC an Irradiated Fuel Management Plan (IFMP), which is an overall plan for the management of used fuel, within 2 years following permanent

cessation of operation of the reactor or 5 years before expiration of the reactor operating license, whichever occurs first. The plan describes the specific periods of storage of spent fuel beginning with the time at which the units are defueled, and ending with the demolition of the ISFSI storage system. Each time period describes: (1) the location of the fuel; (2) methods of cooling; (3) number and type(s) of canisters; (4) a shipping schedule which describes fuel movements (on-site and off-site); and (5) annual cash flow analysis. The IFMP is prepared and issued in Phase 1 of the decommissioning process.

15. **Post-Shutdown Decommissioning Activities Report (PSDAR):** Pursuant to 10 CFR 50.82(a)(4)(i), within 2 years following permanent cessation of operations, the licensee shall submit a PSDAR to the NRC and send a copy to the affected State(s). The PSDAR will include a description of the planned decommissioning activities, a schedule for the completion of these activities, an estimate of the expected costs, and a discussion that provides the reasons for concluding that the environmental impacts associated with the site-specific decommissioning activities will be bounded by appropriate, previously issued environmental impact statements. The standard format for the PSDAR is provided in Regulatory Guide 1.185, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report." The PSDAR will include a description of the method or combination of methods selected for decommissioning and the bases of the DCE. In addition, SCE will be required to prepare and submit in support of the PSDAR a historical site assessment; site characterization survey; and an evaluation of potential environmental impacts in comparison to prior environmental evaluations. The PSDAR is prepared and issued in Phase 1 of the decommissioning process.

16. **License Termination Plan:** Regulatory Guide 1.179, "Standard Format and Content of License Termination Plans for Nuclear Power Reactors," provides the standard format and content of a License Termination Plan (LTP) for Nuclear Power Reactors. As provided in this regulatory guide, "the LTP should discuss the current site radiological condition, remaining remediation activities, and costs for implementing them, final site radiological surveys, and radiological criteria for license termination and

methods for demonstrating compliance." The LTP is prepared and issued in Phase 3 of the decommissioning process.

III. Initial Decommissioning Planning and Near-Term Activities for SONGS

17. Regulatory Guide 1.184 provides overall planning guidance, but concentrates generally on regulatory submittals only, not the planning for decommissioning. Therefore, SCE will utilize the EPRI "Decommissioning Pre-Planning Manual" to develop the initial site-specific decommissioning plan for SONGS. The manual outlines 32 distinct tasks, addressing regulatory, commercial, and personnel-related activities.

18. Complimentary to the EPRI and NRC guidance, SCE also conducted benchmarking trips at three decommissioning nuclear facilities (Kewaunee, Zion, and Crystal River nuclear power plants). The trips will provide SCE with information regarding the decommissioning process that SCE will be able to use as it develops the site-specific decommissioning plan and cost estimate for SONGS.

19. As noted above, the decommissioning process occurs in three phases. SCE is just beginning Phase I and developing the site-specific decommissioning plan and cost estimate.

Phase 1 – Initial Activities

20. **Initial Planning Period:** Initial planning includes appointing team leaders, establishing the organization along with definition of roles and responsibilities, ensuring infrastructure is in place, and developing the necessary accounting systems to capture decommissioning costs. In addition, a key component of the planning is to develop a schedule that identifies the overall plan and provides graphic representation of the decisions made as well as decisions that require confirmation as the project progresses. SCE is in the process of developing this schedule. In addition, the Emergency Plan and Security Plan for SONGS will be reviewed to determine what options can be undertaken for optimization. Separately, the SONGS shutdown safety analyses, updated final safety analysis report (UFSAR) update, and shutdown technical specification will also be prepared.

21. **Pre-SAFSTOR and Regulatory Submittal Activities**: As noted above, during Phase 1, a number of submittals are required in accordance with 10 CFR 50.82 for a plant entering decommissioning.

22. The required certification for cessation of operation and fuel offload are complete.

23. SCE is planning on preparing the PSDAR, IFMP, and DCE in the middle to latter part of the 24 month allotted period. Various options for the length of time for DECON and potential SAFSTOR and the ultimate dismantling of SONGS will be evaluated.

24. Allowing for an appropriate amount of time to prepare and confirm the bases of the three submittals (PSDAR / IFMP / DCE) is paramount. For this reason, SCE plans to take up to a year or more to consider and prepare these three key submittals. Submittal of these documents in the middle to latter part of the 24 month time period also reduces the potential for submittal revisions. The three submittals fulfill NRC decommissioning-reporting requirements and allow full access to the NRC decommissioning funds in the Master Trusts. During this phase, the methods and controls related to system abandonment, procedures update, design change control, and configuration management will be evaluated for change consistent with a non-operating nuclear plant in decommissioning.

25. In addition to preparing these three submittals, SCE will also continue to maintain storage of used fuel in the SONGS 2&3 spent fuel pools, and transfer spent fuel from the spent pools to casks in the SONGS ISFSI in accordance with the NRC license and regulatory requirements for the ISFSI.

26. During Phase 1, NRC regulations limit the use of Master Trusts funds to 3% of the generic "formula amount" provided in 10 CFR 50.75. In subsequent decommissioning phases following the submission of the three submittals described above, NRC's regulations governing the NRC License Termination portion of the decommissioning funds authorize the use of 100% of this portion of the Master Funds for approved NRC License Termination activities. The NRC restrictions on the use of trust funds do not apply to withdrawals from the trust funds for non-radiological costs such as severance, site restoration, and fuel storage.

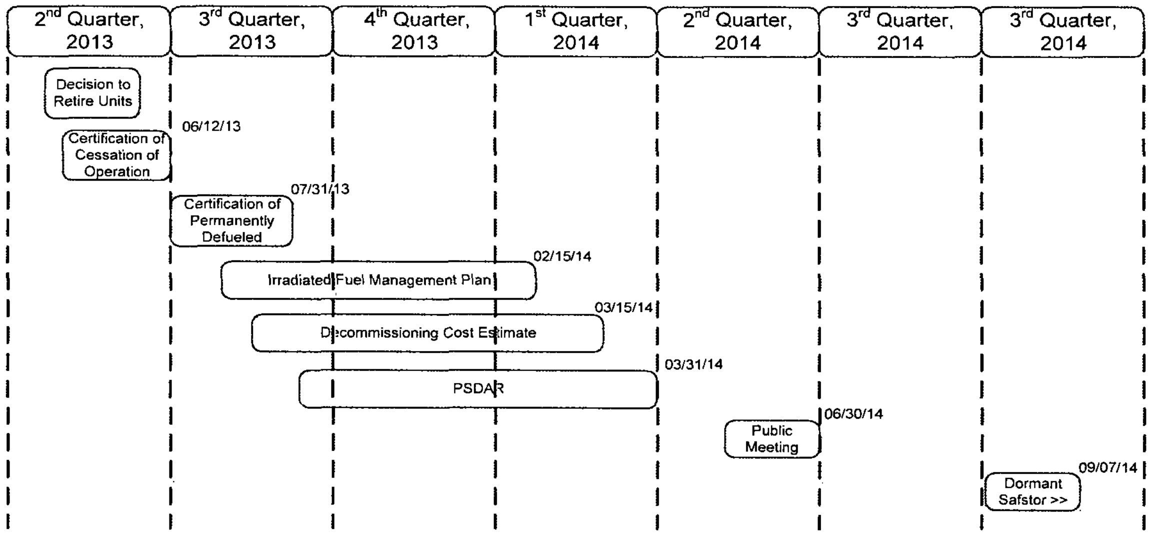
Phase 2 – Storage and Major Decommissioning Activities

27. **SAFSTOR Period**: SCE has not finalized any plans regarding entering SAFSTOR. Contingency plans will be developed for utilizing the ISFSI in the event the DOE does not take possession of the spent fuel. SCE will also evaluate options for the timing and scope of D&D activities, which, among other things, will involve (1) considering the timing of removing spent fuel from the spent fuel pools; (2) evaluating radiological issues; and (3) determining the required end state for the site. For example, although it is possible to begin D&D prior to removing spent fuel from the spent fuel pools, there are fewer radiological safety issues involved with the spent fuel pools empty. SCE will consider these types of issues as it develops these plans.

28. Because the SONGS site is on an easement granted by the United States Navy (USN), the original lease stipulates certain end state conditions that may need to be revisited, particularly with regard to the depth of D&D activities below ground surface. Revisiting these commitments will have a significant effect on the plan for D&D, and the overall cost of D&D. Accordingly, during this period, SCE will seek to develop with the USN a final agreement on the end state of D&D for the site.

29. **Decontamination and Dismantling (D&D) of SONGS 1,2,3**: By current regulations, the D&D must be complete and the land returned to a condition allowing release for restricted or unrestricted use and termination of the licenses within sixty years of the announcement to retire the units (i.e., June, 2073). It is currently assumed that the remaining portion of the decommissioning activities for SONGS Unit 1 will be completed at the same time as Unit 2 and 3. As noted above, SCE will develop D&D plans in order to meet the conditions set in a final agreement with the USN regarding the end state of D&D at the site.

30. SCE anticipates the following general decommissioning timeline for the initial decommissioning planning and near-term decommissioning-related submittals to the NRC regarding SONGS, while acknowledging that the site-specific decommissioning activities plan and cost estimate for SONGS remains subject to various state and federal regulatory approvals:



2nd Quarter, 2013
3rd Quarter, 2013
4th Quarter, 2013
1st Quarter, 2014
2nd Quarter, 2014
3rd Quarter, 2014
3rd Quarter, 2014
Decision to Retire Units
06/12/13
Certification of Cessation of Operation
07/31/13
Certification of Permanently Defueled
02/15/14
Irradiated Fuel Management Plan
03/15/14
Decommissioning Cost Estimate
03/31/14
PSDAR
06/30/14
Public Meeting
09/07/14
Dormant Safstor >>

Phase 3 – License Termination

31. Following Phases 1 and 2 above, SCE will need to submit a LTP to the NRC. As noted above, the LTP will discuss the site radiological condition, remaining remediation activities, and costs for implementing them, final site radiological surveys, and radiological criteria for license termination and methods for demonstrating compliance.

IV. Interim Disbursements

32. SCE estimates the expenditure of up to $282 million (100% share) of SONGS 2&3 decommissioning costs through December 31, 2013. SCE requests the Commission to authorize disbursements of up to $214 million (SCE Share) from the Master Trusts for SCE's share of these costs. Attachment 1 to the advice letter provides a summary of decommissioning costs for the first 18 months of the decommissioning through December 31, 2014.

33. The decommissioning costs incurred in 2013 include (1) Base O&M necessary to ensure the radiological safety and security of SONGS, and to commence decommissioning activities; (2) capital expenditures related to the Independent Spent Fuel Storage Installation (ISFSI) and site-security projects; and (3) other costs such as workers compensation, insurance, and severance (if allowed as decommissioning costs under tax rules). More specifically, as explained in further detail below, the Base O&M decommissioning costs in 2013 are necessary for: (1) commencing a site-specific SONGS 2&3 decommissioning plan and detailed cost estimate, and preparing decommissioning-related submittals to the Nuclear Regulatory Commission (NRC); (2) managing used fuel stored at SONGS; and (3) paying for other near-term non-radiological decommissioning costs, including the option to pay for employee-related decommissioning costs allowable under the Nuclear Facilities Decommissioning Act of 1985 (Decommissioning Act), if certain federal tax issues are resolved favorably. In the advice letter, SCE expressly seeks the authority to propose a different means to recover the severance expenses incurred in decommissioning, if payment from the decommissioning trust would compromise the beneficial tax status of the trusts or if another cost-recovery alternative is appropriate.

34. The NRC permits the use of up to 3 percent of the estimated decommissioning costs pursuant to 10 CFR 50.75 to fund the initial detailed planning for the radiological decommissioning (or NRC License Termination) at nuclear plant sites. The Master Trusts similarly anticipate the use of 3 percent of the amount set by Section 50.75 for detailed planning

purposes. SCE will need to complete this detailed planning by developing a site-specific decommissioning activities plan that will be described in various submittals described above.

35. There will be a number of near-term used-fuel management activities that require funding from the Master Trusts. Although SONGS is permanently retired, SCE must continue to meet applicable NRC requirements during the decommissioning process prior to license termination. In particular, SCE must continue to maintain the safety and security of used fuel for the radiological health and safety of the public. The activities will include storing the used fuel in the SONGS 2&3 spent fuel pools, transferring used fuel from the spent fuel pool to casks in the SONGS Independent Spent Fuel Storage Installation (ISFSI), and continued storage of used fuel in the ISFSI.

36. SCE will assess the feasibility of accelerating the transfer of used fuel from the spent fuel pools to the ISFSI, and also assess isolating the spent fuel pools so that ocean cooling will no longer be required. The costs of these activities are not included in the 2013 costs, and will be identified as appropriate in subsequent advice letters seeking approval of disbursements for future periods.

37. SCE will also incur non-radiological decommissioning costs related to certain support functions for SONGS decommissioning, such as procurement, finance, human resources (HR), and information technology (IT) activities. The non-radiological decommissioning costs also include costs for insurance, workers compensation, and taxes. In addition, the largest near-term expense incurred by SCE that is directly associated with the retirement of SONGS 2&3 are employee-related costs, including labor expenses, costs associated with payments to departing SCE employees at the SONGS site or whose work primarily relates to SONGS 2&3, and assistance with their job searches. SCE has applied to the Internal Revenue Service for a private letter ruling to confirm that disbursements from the decommissioning trust to fund severance would not compromise the trusts' beneficial tax status. As noted above, SCE seeks the authority to propose a different means to recover the severance expenses incurred in decommissioning, if payment from the decommissioning trust would compromise the beneficial tax status of the trusts or if another cost-recovery alternative is appropriate.

V. Designation of Trust Funds Allocable to NRC License Termination

38. The NRC's regulations in 10 CFR 50.75(h)(2) and 10 CFR 50.82 impose restrictions on the use of trust funds designated for NRC License Termination purposes. However, these rules do not apply to amounts authorized by the CPUC to be accumulated and commingled in the Master Trusts for other purposes. NRC allows the commingling of such

other funds, provided that the amounts allocable to NRC License Termination are clearly identified. The NRC License Termination portions of the trust funds for SONGS 2&3 can be identified based upon an allocation derived from the most recent cost estimate submitted by SCE to the CPUC, which assumes a 2013 shutdown of SONGS 2&3, as follows:

		Latest NDCTP Estimate 100% Level	SCE Share*	Calculated Value	Breakdown of Trust Fund** Using Calculated Value
SONGS 2			75.7363%		
	License Termination	849,547	643,415	43%	567,132
	Site Restoration	436,725	330,759	22%	291,544
	Fuel Storage	686,292	519,772	35%	458,148
	Total	1,972,564	1,493,947	100%	1,316,824
SONGS 3			75.7475%		
	License Termination	829,091	628,016	38%	569,761
	Site Restoration	606,393	459,328	28%	416,720
	Fuel Storage	724,291	548,632	34%	497,741
	Total	2,159,775	1,635,976	100%	1,484,221
Grand Total		4,132,339	3,129,923		2,801,045

* Share as of shutdown
** 7/31/2013 Trust Balances

39. Based upon this allocation, the NRC License Termination amount as of December 31, 2012 is $567.132 million for SONGS 2 and $569.761 million for SONGS 3. The remaining amounts in the trust funds would be subject to Commission jurisdiction, but would not be subject to the NRC restrictions applicable to the NRC License Termination amounts.

VI. SONGS Decommissioning Staffing Plans

40. Based on SCE's announcement on June 7, 2013, to permanently retire SONGS 2 & 3, SONGS staffing levels were reduced to approximately 575 employees by October, 2013. Departing SONGS employees and employees who primarily support SONGS will receive payments as allowed under Public Utilities Code Sections 8321 et seq.

41. The reduction to 575 employees is possible because many of the functions that were required to support SONGS 2 & 3 operations are no longer required. SCE developed the SONGS permanent retirement staffing level of 575 by analyzing a

combination of (1) staffing plans of other nuclear facilities that are decommissioning, and (2) the work required in a permanent retirement state.

42. SCE plans to further reduce staffing in 2014 to approximately 400 employees.

43. This organization plan is based upon the 10 CFR 50.82 defueled certification and NRC approval of the 10 CFR 50.54(q) Emergency Plan changes.

44. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on November 13, 2013, at San Clemente, California.

<u>/s/ Thomas J. Palmisano</u>

Thomas J. Palmisano