Report on Nuclear Decommissioning

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For

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Prepared by

Nicholas Capik

ABZ
Engineering & Management Consulting

Geoffrey Griffiths

tlg SERVICES

Bruce Lacy

LacyConsultingGroupLLC
NUCLEAR + BUSINESS + STRATEGY

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Report on Nuclear Decommissioning

EXECUTIVE SUMMARY

The California Public Utilities Commission ("CPUC" or "Commission") established an independent panel of decommissioning experts to examine certain decommissioning cost issues as part of Decision 10-07-047. This Panel was formed in late 2010 to perform six specific tasks in an effort to assist the Commission in future proceedings.

The first task performed by the Panel was to evaluate the 2008 decommissioning cost estimates for Southern California Edison's (SCE's) and San Diego Gas & Electric's (SDG&E's) San Onofre Nuclear Generating Station, Units 2 and 3 (SONGS 2&3), and Pacific Gas and Electric's (PG&E's) Diablo Canyon Power Plant, Units 1 and 2 (DCPP), in order to identify the significant differences between these estimates. The 2008 estimated cost to decommission the SONGS site was $3,659 million as compared to $1,828 million, also estimated in 2008, to decommission the DCPP site. The Panel identified 8 items that account for 99.4 percent of the cost difference between the SONGS 2&3 and DCPP estimates.

The primary difference between the SONGS 2&3 and DCPP estimates identified by the Panel was the assumed site condition at the end of decommissioning. Specifically, the SONGS 2&3 decommissioning estimate assumed that all material added to the site by SCE would have to be removed from the site during decommissioning in compliance with SCE's site lease terms. Conversely, the DCPP decommissioning estimate assumed that only material above three feet below grade would be removed, and that some demolition waste could remain on site if permitted by Nuclear Regulatory Commission (NRC) requirements. The added cost in the SONGS 2&3 decommissioning estimate to remove the material not included in the DCPP estimate was calculated based on the 2008 decommissioning studies to be approximately 73 percent of the difference, or $1,335 million (2008 dollars). This calculated cost includes direct activity cost, waste disposal cost, and indirect costs.

Other significant differences between the 2008 SONGS 2&3 and DCPP estimates identified by the Panel include:

- 10 percent of the difference, or $178 million (2008 dollars), for severance payments required by the California Nuclear Facility Decommissioning Act of 1985 included in the SONGS estimate, but not included in the DCPP estimate;
- 8 percent of the difference, or $147 million (2008 dollars), for additional security costs likely as a result of the physical layout of the SONGS site; and
- 8 percent of the difference, or $144 million (2008 dollars), for large component removal costs.

Also, as part of the first task, the Panel reviewed SCE's $384 million (2007 dollars), 118 percent adjustment to the Palo Verde Nuclear Generation Station, Units 1, 2, and 3 (PV) decommissioning cost estimate. The Panel concluded that the waste burial adjustment of approximately $330 million in 2007 dollars made by SCE was incorrect, and should be revised if used in future proceedings. The remaining three adjustments totaling approximately $98 million in 2007 dollars should be reasonably defended each time they are used in the future as the circumstances and experience that justify such adjustments may change over time.

In its second task, the Panel compared the SONGS 2&3 and DCPP estimates to those for five other non-California sites, including Indian Point Unit 2 (New York), PV (Arizona), St. Lucie (Florida), South Texas Project (Texas), and Vogtle (Georgia). The Panel concluded that the California stations faced several unique challenges, including demolition of a more robustly constructed facility (due to seismic design requirements), and generally higher labor costs. In addition, the California estimates also included larger contingencies than other non-California estimates. Finally, while not significant to being located in California, the California estimates used more realistic assumptions about required fuel storage activities following final shutdown.

In its third task, the Panel considered whether common cost and financial assumptions could be utilized for the SONGS 2&3 and DCPP estimates. The Panel identified several areas where common assumptions could be used in future estimates. The areas where the Panel recommends that common assumptions be used include: DOE performance to remove spent fuel from the sites; waste management approaches and costs; state requirements for site restoration; severance costs; and the use of actual industry decommissioning-related performance and cost data.

The fourth task performed by the Panel was to evaluate whether any actions could be taken by SCE and PG&E to reduce future decommissioning costs or to reduce the uncertainty associated with the estimated costs. The Panel concluded that there were limited opportunities that would reliably reduce future costs, but that current funding requirements might be reduced by revisiting assumptions regarding license renewal, and the likely use of alternate decommissioning methodologies to offset Low-Level Radioactive Waste (LLRW) disposal escalation rates. There were also more opportunities that could be performed now to reduce the uncertainty in estimating the scope of future activities and costs. These opportunities include better utilization of site experts to evaluate decommissioning security needs, and use of data obtained from plant modifications and maintenance concerning volumetric concrete contamination and metal activation to confirm or adjust decommissioning assumptions.

The fifth task performed by the Panel was to evaluate whether any emerging radiological issues existed that could increase future decommissioning costs. The Panel identified several issues that could cause estimates to increase, including the developing industry concerns with tritium and carbon 14 isotopes, and the current lack of a disposal site open to California generators for class B and class C LLRW.

The sixth task performed by the Panel was to evaluate whether future decommissioning cost estimates could be revised to simplify the review process. The Panel is providing recommendations for the organization and scope of future estimate assumptions and the scope of estimate calculations, including waste quantities, labor costs, and other data, to facilitate comparison of different estimates

In addition to these six tasks, the Panel also evaluated the risks associated with decommissioning funding, the use of contingency in the SONGS 2&3 and DCPP estimates, and how the contingency in these estimates related to the risks.

Report on Nuclear Decommissioning

1. INTRODUCTION

The California Public Utility Commission (CPUC or Commission) periodically conducts its Nuclear Decommissioning Cost Triennial Proceeding (NDCTP) to review and set collection amounts for PG&E, SCE and San Diego Gas & Electric Company (SDG&E), collectively the Owners, for the decommissioning of nuclear power plants that provide service to California customers. These nuclear power plants are DCPP, SONGS 2&3, and a 15.8 percent interest in PV.

NDCTP Settlement

In the course of the most recent proceeding in 2009, the Owners and The Utility Reform Network (TURN) agreed on a settlement agreement (Settlement) for concluding the NDCTP. Elements of the Settlement were approved by the CPUC in Decision 10-07-047 (Decision) on July 29, 2010 including the appointment of an Independent Panel (Panel) to examine six issues regarding nuclear power plant decommissioning as follows:

- Identifying, comparing, and explaining the key cost and financial assumptions driving differences in the cost estimates, including SCE adjustments for PV, for the three units.
- Identifying, comparing, and explaining similarities and differences in decommissioning costs, challenges, and approaches for California nuclear units and plants of similar design and configuration in other states.
- Identifying and explaining cost and financial assumptions that could be applied on a common basis to the estimates for the DCPP, SONGS 2&3, and PV sites. The report may include recommendations on proposed common cost and financial assumptions. Depending on economic, technical, and regulatory developments during the triennial period, these assumptions may include an updated start date reflecting the best-available information from the U. S. Department of Energy (DOE) for spent fuel removal, updated LLRW burial rates, etc.
- Identifying and suggesting steps that could be taken to minimize decommissioning costs in the future.
- Evaluating whether emerging radiological contamination issues could increase decommissioning costs and, if so, recommending steps that can be taken to minimize such contamination in the future.
- Suggesting a common format for the preparation of decommissioning cost estimates that would permit greater transparency and comparability.

At an initial hearing required by the Decision on August 27, 2010, a seventh item was added to the list:

- Examining the role of contingency in nuclear power plant decommissioning cost estimating

The Panel

Panel members agreed to by the Owners and TURN and approved by the CPUC in the Decision were Nicholas Capik of ABZ, Inc., Geoffrey Griffiths of TLG Services, Inc., and Bruce Lacy of Lacy Consulting Group, LLC.

Upon notification of their appointment, the Panel began its work in the last week of August by presenting its plans for addressing the issues noted above at a hearing conducted in the CPUC's offices on August 27, 2010.

Conduct of the Panel's Work

Panel members have accomplished their work and preparation of this Report by extensive use of published material, notably the decommissioning cost estimates for the plants noted above, requests for information to the Owners, visits to the plant sites and interviews with site personnel, and interviews with other industry experts with relevant decommissioning experience.

Guiding Principles

Any conclusions about future nuclear decommissioning costs involve a significant amount of informed speculation about events that will only be fully understood in the future, at the time of decommissioning, and which may resemble historical events to a greater or lesser degree as circumstances change. Additional background on selected issues is included in Appendix A. With this background and understanding in mind, several principles guided the Panel members in their work. These principles included:

- Emphasis on establishing a common year for discussing costs – 2008 was selected and numbers from other years were adjusted assuming 3 percent annual inflation.
- Emphasis on critically examining the comparability of numbers – some numbers look alike but have different bases, or are not actually similar.
- Providing a fully public report – this ensures maximum accessibility of the information to anyone who wishes to access it. This sometimes involved greater effort to identify a publicly available source of information, but it avoided needing to obtain permissions from holders of proprietary information, and further avoided the complexities of a public and proprietary version of the Report.
- Unanimous agreement by Panel members on Report content and recommendations – this was a worthwhile principle as it motivated detailed discussion, reliance on facts, and understanding of complex issues, which make a better and more robust Report.

2. CONTEXT OF A DECOMMISSIONING ESTIMATE

In preparing and reviewing a cost estimate it is important to consider the context in which a decommissioning cost estimate is typically prepared. Important aspects to consider include:

- The estimate is for work not expected to be performed until decades into the future;
- Circumstances at the time of decommissioning will likely be different than today;
- The plan used to decommission the station will likely be different from the plan used to develop the estimate; and
- The plan and estimate are expected to be updated periodically to capture changes in economics, regulatory expectations, expected DOE performance, waste disposal options, and many other variables;

The Panel understands that there is a strong desire to have the basis for the estimate be consistent with future decommissioning performance, but historically the variety in approaches used for recently decommissioned similar Pressurized Water Reactors (PWRs) reactors has demonstrated that even decommissioning projects taking place in the same time frame were completed using a wide-range of implementation techniques. Currently the most recent large PWR to begin decommissioning (Zion Station) is expected to use a process substantially different than the previous techniques.

The Panel does believe that the estimate should consider, estimate, and document important cost drivers, which will impact the cost of decommissioning. These cost drivers include:

- Decommissioning strategy
- Timing of plant shutdown
- Desired “end-state” (projected federal, state, local and owner requirements)
- Quantities of waste generated
- Schedule of performance
- Cost of waste disposition (packaging, transportation, and disposal)
- Expected spent fuel management requirements
- Cost of labor
- Program management
- Security
- Indirect costs such as taxes and insurance
- Contingency
- Regulatory agency fees

3. U.S. DECOMMISSIONING EXPERIENCE

Within the past two decades six domestic, commercial PWRs[1] have completed most of the work necessary to "decommission" the units. This decommissioning work included removal and disposal (or storage) of radioactive materials necessary to satisfy both federal and state radiological release criteria, management of spent nuclear fuel, demolition of most structures, and removal of potentially hazardous (but non-radioactive) materials as part of the "site restoration". Five of the units were stand-alone units, with each being the only nuclear asset in the owners generating portfolio. The sixth unit[2] was co-located on a station with two additional operating reactors. It is expected within the next decade or so an additional two PWRs[3] (co-located at a single station) will also have been decommissioned. There are other domestic PWRs (generally older reactors) currently being decommissioned. Most are being safely stored until one or more co-located units cease operation, at which time they will be decommissioned together. In addition, there is also one Boiling Water Reactor[4] (BWR) located in northern California in the process of being decommissioned.

The experiences and reported results from these decommissioning projects are valuable in understanding and developing future decommissioning plans and estimates. In considering these experiences, it is important to consider the circumstances and context of each decommissioning project, and its applicability to estimating future costs. The reader is reminded that this section is not intended to be a comprehensive compilation of U.S. decommissioning experience, but a summary to provide some perspective of past results.

Differences in Estimated and Reported Costs

A summary of experience information related to the six reactor decommissioning projects is provided in Table 3.1. In reviewing the information provided in this table the reader is reminded that the "Reported Cost" represents both costs incurred and projected costs going forward, and that each reactor owner has likely reported costs to satisfy their regulators, not to a single standard.[5] The "reported cost" was extracted from a variety of sources, including license termination plans (submitted to the NRC) and information provided to ratemaking authorities. As such, it is very unlikely that the reported costs for each of the reactors include all of the same work items. To further understand this source of information, extracts of the reported costs are provided in Appendix B.

In order to compare the pre-decommissioning estimated costs against "reported costs", the Panel recognized that the "time the pre-decommissioning estimate was developed" and availability of that estimate information was important. To eliminate any bias, the Panel elected to use the values

[1] These six units are Connecticut Yankee (Connecticut), Maine Yankee (Maine), Rancho Seco (California), Trojan (Oregon), Yankee Rowe (Massachusetts), and San Onofre Nuclear Generating Station, Unit 1 (California).
[2] San Onofre Nuclear Generating Station, Unit 1 was collocated with SONGS 2&3.
[3] Zion Station, Units 1&2 (Illinois).
[4] Humboldt Bay Power Plant, Unit 3 (California).
[5] Projected costs, by necessity, include some assumption about DOE performance. Care should be exercised when comparing these future costs because many of the assumptions about DOE performance are most likely incorrect.

identified by the NRC in their "Frequently Asked Decommissioning Questions" publication (relevant information also included in Appendix B). For the one reactor not listed in the NRC publication, the estimate prepared just prior to starting dismantling was used.

From a review of the information provided in Table 3.1 it is clear that the costs estimated for decommissioning prior to the start of dismantlement were substantially less than the actual costs incurred for dismantlement. The Panel concludes that the early decommissioning estimates did not fully account for the actual circumstances encountered during decommissioning. Differences between the estimated and reported costs were a result of:

- The estimates were not consistent with the timing of the reactor shutdown. Each of the six units permanently ceased operations prior to the end of their operating license (all units shut down prematurely). This impacted the funds available in the decommissioning trusts at the time of decommissioning, and forced the transition from operations to decommissioning to occur without detailed initial plans.
- The estimates did not account for the all costs associated with spent fuel management, particularly the costs likely incurred due to the delay in the U.S. Department of Energy's (DOE's) performance (costs of transferring spent fuel from "wet" to "dry" storage and maintaining fuel in dry storage). Although there was limited dry storage experience at other reactor sites, none of the shutdown reactors had dry fuel storage facilities available at the time of shutdown.
- The estimates were based on a wide-range of assumptions regarding the availability and cost of LLRW disposal. Some estimates assumed that waste would be disposed of in to-be-developed facilities within a low level waste compact. During decommissioning, the expected availability of waste disposal facilities changed as Barnwell threatened to cease accepting waste, resulting in some owners expediting the removal, packaging, and transport of waste to meet perceived deadlines. Offsetting these uncertainties and difficulties with Barnwell, Envirocare of Utah (now Energy*Solutions*) became available for much of the LLRW produced during decommissioning. Barnwell did eventually close to most generators.[6]
- The estimates did not accurately consider the extent of radioactive contamination, both inside and outside the confines of plant buildings. This contamination was principally due to leaks from systems that ultimately resulted in contaminated concrete and soil in below-grade areas. This contamination resulted in a need to remove and dispose of a substantially greater volume of material than was estimated to be needed prior to reactor shutdown. A summary of reported radioactive waste quantities is provided in Table 3.
- Some of the estimates developed prior to shutdown were based on a NRC license termination process and criteria that were substantially changed in the mid-1990s. Some of these changes were most likely the direct result of the earliest decommissioning

[6] Barnwell (South Carolina) first closed in 1994, but reopened a year later. It subsequently closed to out-of-compact generators in 2008.

experiences at plants shut down in the early 1990s. The NRC license termination process changes resulted in more flexibility in developing decommissioning plans and performing dismantling and decontamination work, but also required the use of statistics and improved radiation detection equipment to prove that the release criteria had been satisfied.

- Many of the estimates did not consider that state authorities would impose their own standards as part of the decommissioning process. States were particularly engaged in determining what materials (both radioactive and non-radioactive) could remain on site at the end of the decommissioning process. The states, in general, required lower levels of residual radioactivity than permitted by the NRC, and had a substantial influence on the ultimate "site restoration" criteria.
- The estimates were developed prior to the terrorist attack on September 11, 2001, and did not consider the substantial post-9/11 security changes required of reactor licensees.
- The estimates were not consistent with the contracting approaches utilized by each of the owners. Owners of two of the plants, Maine Yankee and Connecticut Yankee, attempted a near turnkey contracting approach to decommissioning by use of a Decommissioning Operations Contractor (DOC). In both cases, the DOC was similar to a general contractor. The DOC provided all necessary labor and skills to complete the job for a fixed price, and accepted some risk. Both of these owners encountered difficulties with this approach and reverted to owner-managed projects.

Ongoing Decommissioning Experience

Currently in the U.S. there is one power reactor undergoing decommissioning, Humboldt Bay Unit 3 (Humboldt Bay), and two power reactors, Zion Units 1 and 2 (Zion), scheduled for decommissioning. All three reactors have been in safe-storage configurations for more than a decade. Humboldt Bay is being decommissioned using the tested technique of an owner-managed decommissioning project. The Zion reactors are expected to be decommissioned by an independent contractor, without any substantive owner management or intervention (i.e., the license has been transferred to the contractor). The Zion decommissioning strategy appears to be based on transferring all spent fuel to an on-site Independent Spent Fuel Storage Installation (ISFSI) prior to dismantling, and the availability of very low-cost waste transportation and disposal facilities.[7] These low-cost facilities will permit "wholesale" removal of plant equipment and structures, with minimal concern for cost of waste disposal. This strategy may be very cost-effective, and provide some indication of a bounding "low-cost" decommissioning project, but may be a difficult strategy to rely on for estimating the cost for future decommissioning projects since low-cost waste disposal may not be available. Nevertheless, both projects will offer additional experience that should be considered in future decommissioning estimates.

[7] In this case, the decommissioning contractor owns a low-level radioactive waste burial site, and thus has more flexibility in accounting for disposal costs.

Lessons Learned

Experiences have been reasonably well documented in publications that can be retrieved and referenced in the future. Two excellent sources of experience information include Electric Power Research Institute (EPRI)-sponsored lessons learned documents, and the information recorded in the NRC ADAMS system (well-organized source of docketed information that can be electronically retrieved). Many of the documents used in preparing this decommissioning experience section have been obtained from these sources. It should be noted that there are and will be limitations in the disclosure of experiences and costs, particularly where private companies have developed proprietary technologies or practices.

There continues to be a need to incorporate current and future relevant lessons learned into future estimates and decommissioning projects. For instance, reactor licensees continue to make modifications or replace components to support plant operations. These experiences are relevant, particularly in relationship to waste packaging, transportation, and disposal. There may also be relevant "foreign" lessons learned, particularly where their waste management practices have evolved to deal with relatively restrictive and costly LLRW disposal.

Table 3.1 – U.S. Industry PWR Decommissioning Experience Summary

Station	Reported Cost (millions of 2008 dollars) [3, 4]	Estimated Cost (millions of 2008 dollars) [7, 8, 9]	Rating (MWth)	Operating License Issued	Permanent Cessation of Operations	Start of Decommissioning[5]	Decommissioning Completed [6]	Notes
Connecticut Yankee (Connecticut)	1,140	626	1,825	1974	1996	1998	2007	Station also referred to "Haddam Neck"
Maine Yankee [1] (Maine)	743	538	2,700	1973	1997	Immediate	2005	
Rancho Seco [10] (California)	593	668	2,772	1974	1989	1997	2009	
San Onofre Unit 1 [2] (California)	843	636	1,347	1967	1992	1999	n/a	LTP to be submitted concurrent with operating units decommissioning
Trojan (Oregon)	610	586	3,411	1975	1992	Immediate	2005	Major structures demolition has taken place after 2005
Yankee Rowe (Massachusetts)	751	464	600	1963	1991	Immediate	2007	

Notes

1. Plant shutdown in December 1996 - declared permanent cessation of operations in August 1997.
2. San Onofre Unit 1 cost based on $659 million recorded costs through 2008 (costs considered reasonable by CPUC) and $184 million going forward costs (approved in most recent NDCTP).
3. Converted to 2008 dollars by escalating reported costs using CPI Services index. Costs extracted from License Termination Plan unless otherwise noted
4. Cost may not include all decommissioning costs "license termination", spent fuel management, site restoration. These may not include all post-shutdown costs. Some costs could have been considered operations and maintenance expenditures.
5. "Immediate" means promptly after permanent cessation of operations
6. Spent fuel remains stored on site, some radioactive waste is in storage at each of the sites, with the exception of Trojan.
7. Costs extracted from NRC's "Frequently Asked Questions About Reactor Decommissioning" with the exception of San Onofre 1. Converted to 2008 dollars by CPI Services Index.
8. San Onofre 1 costs extracted from 1998 cost study. Converted to 2008 dollars by CPI Services Index.
9. Other Estimated Costs exist, and may have been used in other regulatory proceedings.
10. The reported cost includes all license termination costs (spent-to-date and projected), but includes only spent fuel costs through 2008. Site restoration costs not included (buildings still standing).

Table 3.2 – U.S. Industry Decommissioning Experience Radioactive Waste Volume / Cost

The following table provides a summary of waste costs and volumes reported by PWRs decommissioned in the United States

Plant	Waste Disposal Cost (mixture of year dollars, generally seems to be between 1997 and 2003)	Waste Disposal Mass (lbs.) (ft3) (includes all low-level mass reported by station in the reference document)	Average Cost Per Unit Quantity (no specific interpretation of year dollars)
Maine Yankee [1]	< $200 M (number not directly reported – Panel member interpretation)	246,000,000 lbs.	<$1 / lbs.
Connecticut Yankee[2]	< $230 M (number not directly reported – Panel members interpretation)	265,410,664 lbs.	<$1 / lbs.
Rancho Seco[3]	Panel did not find a published encompassing waste disposal cost value. There was a going forward value ($28M) that excluded much of the timeframe when work was done	612,155 ft3	Not calculated
SONGS 1 [4]	Panel did not find a published total waste disposal cost value	170,000,000 lbs.	Not calculated
Trojan[5]	$51M	436,961 ft3	Approximately $100 / ft3
Yankee Rowe [6]	Panel did not find a published encompassing waste disposal cost value. There was a going forward value ($20M) that excluded much of the timeframe when work was done	480,512 ft3	Not calculated

Notes:

1. Maine Yankee Decommissioning - Experience Report, Detailed Experiences 1997-2004, EPRI Report 1011734, Final Report, May 2005, Table E-1, Summary of Maine Yankee Waste Shipped 1998 – 2005
2. Connecticut Yankee Decommissioning – Experience Report, Detailed Experiences 1996-2006, EPRI Report 1013511, Final Report, November 2006, Table A-1, Projected Waste Quantities
3. Rancho Seco Nuclear Generating Station Decommissioning - Experience Report, Detailed Experiences 1989-2007, EPRI Report 1015121, Final Report, December 2007, A.1 Ranch Seco Lifetime Waste Quantities
4. Testimony on SONGS 1 Decommissioning Work, Completed and Remaining Work Scope, April 3, 2009 (133 million lbs. “to-date”, 37 million lbs. projected).

5. Waste Cost Obtained from Rev. 16 to License Termination Plan, Waste volume extracted from Paper presented at WM'06 Conference, February 26-March 2, 2006, Tucson AZ, TWO APPROACHES TO REACTOR DECOMMISSIONING: 10 CFR PART 50, LICENSE TERMINATION AND LICENSE AMENDMENT, LESSONS LEARNED FROM THE REGULATORY PERSPECTVIVE, Bruce A. Watson, John T. Buckley, and Claudia M. Craig, U.S. Nuclear Regulatory Commission, Office of Nuclear Materials Safety and Safeguards, Decommissioning Directorate (T7E18) Washington, D.C. 20555
6. Extracted from Yankee Nuclear Plant Station License Termination Plan, Rev. 1, November 2004

4. COMPARISON OF THE 2008 SONGS 2&3 AND DCPP DECOMMISSIONING COST ESTIMATES AND EVALUATION OF SCE ADJUSTMENTS TO THE PV DECOMMISSIONING COST ESTIMATE

Nuclear power plants are typically licensed for a 40-year operating period, with the option of applying to the NRC for an additional 20 years of operation for a total of 60 years.[8] When a nuclear power plant is shut down for the last time, the plant is dismantled (decommissioned), and any radiological or other hazards removed from the site or remediated to permit restricted or unrestricted access to the site.[9]

The NRC requires that the owner of a nuclear power plant provide assurance that the bulk of the funds needed to decommission the nuclear power plant are available when the power plant ceases operation.[10] Most owners perform a site-specific estimate of decommissioning costs for each nuclear power plant, and collect funds for decommissioning over the life of the power plant.[11]

California has two operating nuclear stations, SONGS 2&3, consisting of two PWRs, operated by SCE, and DCPP, consisting of two PWRs, owned and operated by PG&E.[12]

Both SCE and PG&E performed site-specific decommissioning cost estimates in 2008.[13] The SCE estimate for the SONGS two unit station was $3,659 million in 2008 dollars. The PG&E estimate for the DCPP two-unit station was $1,828 million in 2008 dollars.

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[8] Not all operating reactors have had their licenses renewed. Some operating reactors have yet to submit applications to the Nuclear Regulatory Commission for license renewal. In addition, a few other reactors permanently ceased operation prior to obtaining license renewal. There is no "guarantee" that an operating license renewal will be approved by the NRC. To date, for those operating reactors that have been granted a license renewal, it has generally taken between two and two and one-half years from the date that the application is received to the date the NRC has issued the renewed license. In addition, three reactors required a longer three to four year review and approval period. This time frame is generally consistent with the NRC's 30-month licensing milestone schedule. There are four reactors, currently in the license renewal process, that have submitted their applications approximately 4 to 5-1/2 years ago (Indian Point 2&3, Vermont Yankee, and Pilgrim). The Vermont state senate and governor are actively pursuing the permanent cessation of Vermont Yankee reactor operations at the end of the current operating license expiration date.

[9] The owner of the site decides whether to release the site for unrestricted use, or to apply for restricted use of the site. The term "decommission" is defined in 10 CFR 50.2, and includes only those actions required to terminate the NRC operating license. When used in this report, the term "decommission" will be used with its broader meaning including all post-shutdown activities and costs.

[10] 10 CFR 50.75.

[11] Through the late 1990s, all nuclear power plants were rate-regulated by state or federal agencies such that there was reasonable assurance of operating revenue. For such rate-regulated plants, the NRC allowed collection of decommissioning funds over the operating life of the plant. When nuclear power plants were sold to non-rate-regulated entities starting in the late 1990s, to transfer the operating license for the power plant, the NRC required that decommissioning funds be guaranteed at the time of sale, rather than allowing collection over the operating life.

[12] SONGS 2&3 is co-owned by SCE, SDG&E and the City of Riverside, with ownership shares respectively of 78.21 percent, 20.00 percent and 1.79 percent. Both SCE and PG&E owned and operated other nuclear power plants; SCE operated a third nuclear power plant on the SONGS site, SONGS Unit 1, and PG&E operated Humboldt Bay. SONGS Unit 1 was shut down in the early 1990s, and is largely decommissioned. Humboldt Bay is currently being decommissioned.

[13] The SCE estimate for SONGS 2&3 was performed by ABZ, Inc. The PG&E estimate for DCPP was performed by

The first task assigned to the Panel was, in part, to review both the SONGS 2&3 and DCPP cost estimates to identify, compare, and explain the key cost and financial assumptions that led to differences in these estimates.

To perform this task, the Panel reviewed the SONGS 2&3 and DCPP studies, and requested additional documents from SCE and PG&E. The Owners provided additional, and supplemented that information with answers to specific questions posed by the Panel. In addition, the Panel visited each of the sites, including the PV site operated by Arizona Public Service.[14]

At each site, the Owners presented subject matter experts requested by the Panel to respond to detailed questions about decommissioning, as well as the design, operation, and maintenance of the power plants.

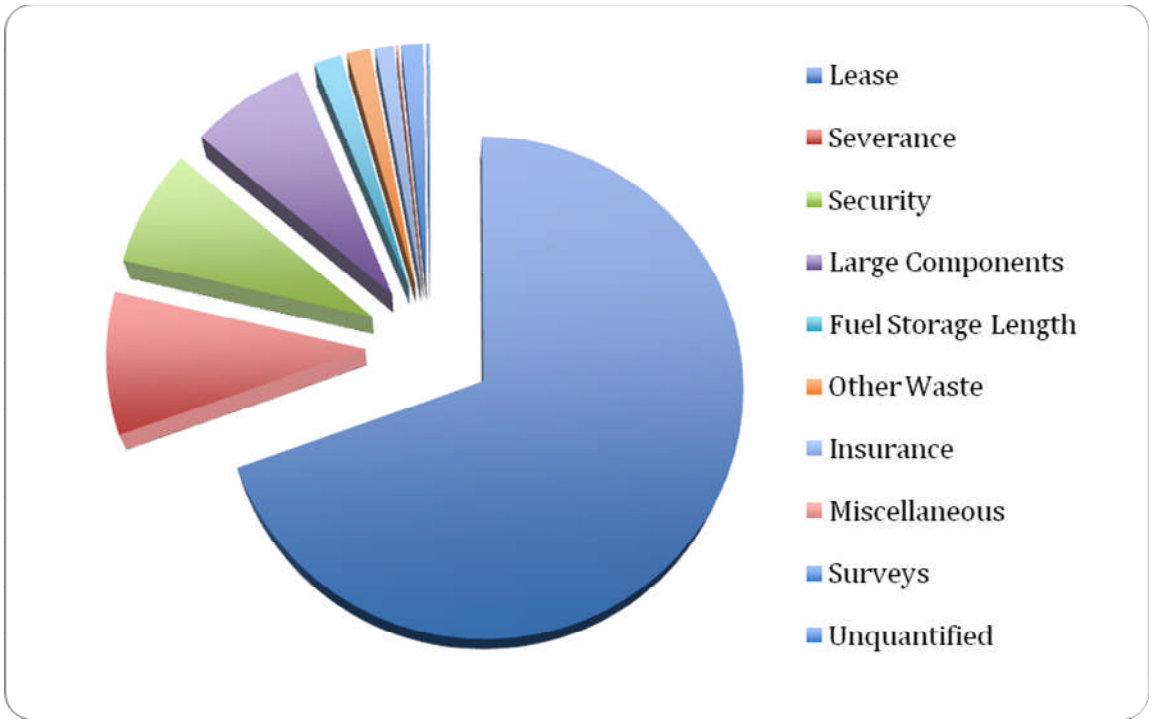
After review and evaluation of the documents provided by the Owners, and consideration of the information obtain on the site visits and provided by the subject matter experts, the Panel has identified eight items that account for 99.4 percent of the cost difference between the SONGS 2&3 and DCPP estimates. These items are shown in figure 4.1:[15]

TLG Services, Inc.

[14] SCE owns 15.80 percent of PV and collects decommissioning funds for its share of decommissioning costs for that facility. SCE made adjustments to the owner-provided decommissioning cost estimate for PV for the purposes of determining its decommissioning fund collection. SCE's adjustments to that study are also addressed in this report.

[15] Detailed calculations used to generate this chart are included in Appendix C.

Figure 4.1 - SONGS 2&3 and DCPP Estimate Differences



The primary difference between the SONGS 2&3 and DCPP estimates identified by the Panel is the assumed site condition at the end of decommissioning. The SONGS station is located on land leased from the United States Navy (Navy Lease).[16] The Navy Lease provides requirements related to the restoration of the site prior to termination of this lease. Generally, the Navy Lease requires that any and all improvements installed or constructed be removed, and the site restored to a satisfactory condition, including decontamination of the site and surrounding area resulting from operation of the station.[17] In addition, SCE has a separate lease from the California State Lands Commission (State Lands Lease) for its offshore water circulating conduits.[18] The State Lands Lease requires that the conduits be excavated and removed in their entirety.

The DCPP site is located on land owned by PG&E, and does not have leases from the United States Navy. While PG&E does have a lease with the California State Lands Commission, that lease has not been identified by PG&E as having the same kind of impact on DCPP decommissioning as the State Lands Lease does at SONGS 2&3. Thus, the scope of work in the two estimates is different.

[16] The lease, between the United States of America, Southern California Edison Company, and San Diego Gas & Electric Company, was signed on May 12, 1964. It has been subsequently amended to address changes such as the creation of the Nuclear Regulatory Commission (which superseded the Atomic Energy Commission).
[17] The lease provides that any natural material cut or filled in the necessary excavation and grading of the site need not be restored.
[18] Easement lease agreement between the California State Lands Commission, SCE, and SDG&E, November 11, 1974, for SONGS Units 2&3.

The two estimated costs reflect this difference. The SONGS 2&3 estimate assumes that all material added to the site by SCE is removed during decommissioning. The DCPP estimate assumes that most radioactive material is removed, and that all structures above three feet below grade are removed.[19] As a result of these differing scopes, the SONGS 2&3 estimate calculates that approximately 2.8 billion pounds of material will be removed from the site during decommissioning, and the DCPP estimate approximately 1.0 billion pounds of material.

The 2008 SONGS 2&3 decommissioning cost estimate did not contain sufficient information to readily determine the exact cost associated with the removal of material above that included in the DCPP estimate. For the purposes of this task, the Panel has estimated this cost by estimating three components:

1. The direct activity cost associated with removal of the added material;
2. The disposition cost associated with the added material (clean or contaminated burial, as appropriate, and transportation and packaging costs); and
3. The indirect costs associated with this added work scope.

The indirect costs are the most difficult to estimate using the 2008 estimate. For the purposes of this report, the Panel assumed that indirect costs are directly proportional to direct costs. To confirm the applicability of this assumption, the Panel calculated and reviewed additional performance metrics.[20] All of these metrics support the Panel assumption that assuming indirect costs are linear with scope is a reasonable assumption for this purpose.

The Panel calculated that the direct activity cost associated with the added material was approximately $300 million, the disposition cost approximately $194 million, and the indirect cost approximately $840 million (all 2008 dollars, including 25 percent contingency). The Panel recommends that a more accurate value be determined for future NDCTP by developing a decommissioning cost estimate specifically for the desired scope.[21]

[19] The NRC has two criteria for reducing residual radioactivity sufficiently to terminate a nuclear power plant license: As Low As Reasonably Achievable (ALARA), and 25 millirem (mrem) per year total estimated dose equivalent (TEDE) to an average member of the critical group. All radioactivity resulting from operation of a nuclear power plant need not be removed from the site so long as both of these criteria are satisfied. The EPA has potentially more restrictive limits. The NRC, however, views that complying with ALARA usually results in an owner meeting the EPA limits. NUREG 1628, June 2000.
The 2008 DC estimate assumes compliance with NRC requirements. Namely, sufficient radioactive contamination is removed to demonstrate compliance with the 25 mrem per year NRC standard (implicitly assuming that this also satisfies ALARA), and that remaining clean material, as well as concrete contaminated with solely tritium and carbon 14, remain on the site, and are used as fill material.

[20] The term “metrics” is intended to capture measures of achievement per unit, such as material removed per year, or material removed per labor hour.

[21] The SONGS 2&3 estimate also includes approximately $50 million (2008 dollars) for removal of offshore cooling water conduits required by the State Lands Lease.

The second largest difference between the SONGS 2&3 and DCPP estimate is the inclusion of severance costs in the SONGS estimate. These costs were included by SCE to comply with the California Nuclear Facility Decommissioning Act of 1985. The cost included by SCE in the SONGS 2&3 estimate is approximately $178 million (2008 dollars, including 25 percent contingency). The Panel understands that, during the proceeding, PG&E proposed an addition of $135 million to the DCPP decommissioning cost estimate for employee termination costs. The Panel also understands that this amount was calculated using a similar methodology, with the smaller total reflecting, in part, the smaller staff size at DCPP, and that this amount was approved by the Commission in the Decision.[22]

The third largest difference between the SONGS 2&3 and DCPP decommissioning estimates relates to security costs during decommissioning. This difference is estimated to be $147 million (2008 dollars, including 25 percent contingency).

The Owners are required by the NRC to provide physical security for each nuclear power plant station as described in 10 CFR 73. Estimated costs to comply with these security requirements include management staff, training, supervisors, guards, and licensing compliance. NRC security requirements vary based on the site layout, building design, and other factors. The security challenges are quite different between SONGS 2&3 and DCPP. The SONGS site is located adjacent to a public beach and to an interstate highway, whereas the DCPP site is located approximately centrally on a large parcel of PG&E land. The proximity to public areas at SONGS results in different security needs than exist at sites where public access is more distant.

The Panel reviewed the estimated security costs in both the SONGS 2&3 and DCPP estimates, and discussed the security needs and planning with the specialists at each site. The Panel concludes that security needs will vary by site, and that the security department at each site should be involved in the next decommissioning estimates to ensure that the estimated costs reflect the projected security needs during decommissioning.

The fourth largest difference between the SONGS 2&3 and DCPP decommissioning estimates relates to the estimated cost to remove and disposition the reactor vessel and its internals, and other large components including steam generators, the pressurizer, and reactor coolant pumps. This difference is estimated to be $144 million (2008 dollars, including 25 percent contingency). While these activities will be required for most decommissioning projects, there is currently limited experience with removing reactor vessel internals, and even less experience in segmenting a large reactor vessel. ABZ and TLG approach estimating this cost from different directions, and with different assumptions. Specifically, ABZ assumes that the scope and cost of this activity in the future can be determined using the experience to-date. TLG, however, assumes that additional experience will be gained in these activities prior to performance, and that the future performance of these activities will be routine and will not incur the same costs and effort as did the early projects. At present, neither approach can be judged to be more

[22] Settlement Agreement, Appendix B to 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, Decision 10-07-047, dated July 29, 2010.

accurate or reliable than the other method. The difference in methods relates more to a measure of conservatism than to a specific estimating approach.[23]

The fifth through eighth differences collectively represent only three percent of the total difference, and include disposition of other radiological and non-radiological waste on site at final shutdown, insurance costs, costs associated with the length of dry fuel storage, and survey costs.[24]

[23] ABZ and TLG assign different line item contingencies to these activities, reflecting the judgment as to the conservatism of estimated costs. In the 2008 studies, the ABZ estimate assigns 27 percent contingency to these line items while the TLG estimate assigns 66 percent contingency.

[24] For each of the costs except survey costs, the SONGS 2&3 estimate is greater than the DC estimate. For survey costs, given the nature of the SONGS 2&3 Navy Lease, the scope of surveys following dismantlement is significantly smaller, and thus the DC estimate is larger.

SCE Adjustments to the PV Estimate

SCE, as part the most recent NDCTP, made four adjustments to their $324.4 million, 15.8 percent share of the PV estimate performed by TLG on behalf of the plant operator, Arizona Public Service, as follows (all costs in 2007 dollars):

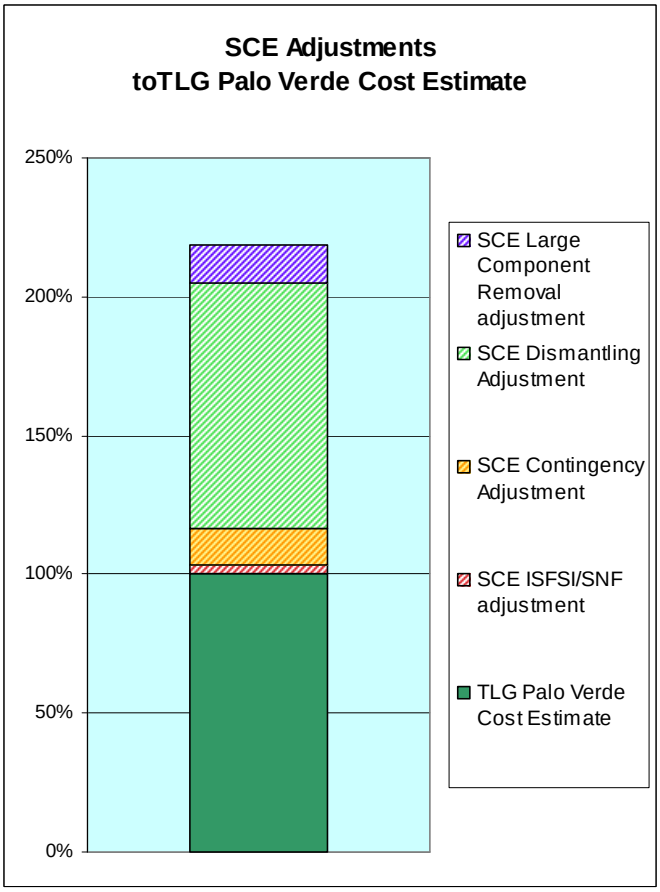
- Large component removal adjustment, $43.7 million
- Net dismantling and disposal adjustment (waste burial), $330.1 million
- Contingency adjustment, $43.3 million
- Net Spent Fuel Dry Storage Adjustment, $10.9 million

The impact of these adjustments on the PV cost estimate on a percentage bases is shown in Chart 4.1.

The Panel is not opposed in principle to adjustments to decommissioning cost estimates, and understands that different owner interests and regulatory policies may make such adjustments appropriate.

The Panel examined each of these adjustments and the supporting basis with the following results:

Chart 4.1



The net dismantling and disposal adjustment is the largest adjustment and is based on the premise that the LLRW Class A direct burial waste volumes reported in the 2007 PV study represent the total volume of Class A waste to be disposed of. This direct burial waste volume in the 2007 study is less than the total expected by SCE based on the 1998 PV decommissioning cost estimate study and they adjusted the 2007 study cost to reflect a direct burial waste volume corresponding to the 1998 study. This adjustment by SCE is incorrect, however, in that it does not include the significant volume of Class A waste to be disposed of through waste processing and conditioning which is included in the 2007 PV report. The result of SCE not including the volume of processed waste is that the SCE adjustment should be substantially reduced. Any future use of an adjustment related to waste burial volume needs to include consideration of the waste volumes to be disposed of through processing and conditioning. The basis for this misunderstanding appears to originate in 2001 when the separation of Class A waste

disposal into two components, direct burial and waste processing, was introduced into the PV study. The use of waste processing was implied in the text of the study, but was not separately itemized in the waste volume summary. This cost impact of this adjustment in 2001 was clouded by use of a new waste burial rate ordered by the CPUC that was higher than that used in the 2001 study. In 2004, SCE again made the burial volume adjustment based on comparison with the 1998 study; however, at this point the 2004 study explicitly itemized the waste processing volume. This key information was missed by SCE. The higher CPUC burial rate was again used and combined with the erroneous burial adjustment resulted in a record high adjustment. In 2007, notwithstanding that the waste processing volume was explicitly listed, SCE again made the burial volume adjustment which was further adjusted upward by their experience with decommissioning SONGS 1. However, the higher burial rate used in the 2001 and 2004 adjustments was not used in the 2007 adjustment with the net result that the 2007 adjustment was slightly less than that used in 2004. The rate impact of this series of adjustments requires a separate study to determine the impact of waste volume adjustments by SCE and burial rates ordered by the CPUC over the three previous nuclear decommissioning rate proceedings.

The large component removal adjustment is based on SCE's experience with large component removal as part of the SONGS 1 decommissioning. The value for large component removal in the PV study is based on the estimator's use of other industry experience up to the time the study was completed. Future development of this adjustment should be documented and explained based on industry experience including disposal by SCE of the original SONGS 2&3 steam generators.

The contingency adjustment is based on use of different contingency values in different regulatory jurisdictions. The value used by Arizona Public Service, the operator and owner of the largest share of PV, is smaller than that used in the NDCTP, and SCE has adjusted the cost estimate accordingly. The amount of this adjustment in the future will depend on the contingency values used in future studies and accepted in future NDCTP's.

The spent fuel dry storage adjustment is based on the assumption in the PV estimate that at a fixed point in the future, the site will no longer be responsible for the cost of dry storage, in that the DOE will become fully responsible based on the DOE's delay in fulfilling the terms of the Standard Contract. As indicated in the possible cost reduction options discussed in Section 7, this is one possible approach to dealing with the cost impact of DOE delay. However, also as discussed in Section 7, such an approach represents some complicating issues. SCE has adjusted the PV cost estimate to comport with the current practice in the NDCTP to fully fund the dry storage costs until DOE final acceptant of fuel is assumed complete without regard to possible recovery of damages from the Federal government due to DOE delay.

5. U.S. DECOMMISSIONING COST COMPARISONS

Comparison of the DCPP, SONGS 2&3, and PV units with other units across the United States provides useful insight into the variations and commonalities that exist in decommissioning cost estimates. Comparison puts the range and relative size of estimates into perspective and leads to better questions and answers when examining and comparing cost estimates and ultimately the potential to better understand historical and future decommissioning cost issues.

Comparison of decommissioning cost estimates requires care to not oversimplify (and compare costs at too high of a level), or to get lost in the details, of which there are many. Useful comparison requires confidence that the data being compared is even comparable data. Several of these important comparison issues are discussed, including the challenges of using cost estimates created in different year dollars, and the incorporation of varying amounts of contingency into cost estimate details.

Selecting plants for comparison

The comparison process began by selection of comparable plants. The Panel looked for plants of similar reactor type, reactor vendor, and construction period on the assumption that this would reduce (but not eliminate) major variations in regulatory requirements and construction practices that can exist over long periods. The Panel also looked for plants of similar size, assuming that similar size would result in similarity in size of components and amount of material to be handled as part of decommissioning. A final objective was geographical diversity.

An equally important and challenging objective was to obtain decommissioning cost estimates that are reasonably current, and can be shared publicly. Public availability was a limiting factor in the number of studies available, and required directly contacting utilities and state regulatory commissions to obtain copies.

The first step, based on the reactor type and vendors for the California plants of interest, was to list the U.S. PWRs designed by Westinghouse (W) and Combustion Engineering (CE). This list was then winnowed down based on comparability of size and availability of a current study. The result was the selection of cost studies for Indian Point, Unit 2 (IP-2), St. Lucie Units 1 and 2 (St. Lucie), South Texas Project, Units 1 and 2 (STP), and Vogtle Units 1 and 2 (Vogtle). Each of these plants brings unique characteristics for use as a comparison. The plants and additional information about each plant are listed in Table 5.1. Summary information for these plants and their cost studies is listed in Table 5.1 along with the same information for DCPP, SONGS 2&3, and PV.

IP 2, similar in design and size to DCPP, brings the perspective of a plant with east coast labor costs and ground contamination issues.

St. Lucie, similar in design to SONGS 2&3 but smaller in size, has two steam generators per unit like SONGS 2&3 instead of the four associated with the Westinghouse design. Similar to SONGS 2&3, it is a coastal site. Of the plants being compared, it is the smallest plant as measured by Mega-Watts electric (MWe) and has the oldest decommissioning cost estimate, dating from 2004.

STP, similar in design and size to DCPP, brings a plant near the Gulf of Mexico that uses a large cooling lake.

Vogtle, similar in design and size to DCPP, represents a river-sited plant in the southeast. Vogtle also had the most current cost estimate, completed in 2009.

Table 5.1 - Plants for Comparison

Unit	State	Reactor Vendor	Net MWe	Year Current Operating License Expires	Cost Estimate Year/Vendor
DCPP 1	CA	W	1,138	2024 License Renewal (LR) pending	2008/TLG
DCPP 2	CA	W	1,151	2025 LR pending	2008/TLG
IP 2	NY	W	1,035	2013 LR pending	2007/TLG
PV 1	AZ	CE	1,333	2024 LR pending	2007/TLG
PV 2	AZ	CE	1,336	2025 LR pending	2007/TLG
PV 3	AZ	CE	1,334	2027 LR pending	2007/TLG
St. Lucie 1	FL	CE	856	2036 w/LR	2004/TLG
St. Lucie 2	FL	CE	856	2043 w/LR	2004/TLG
SONGS 2	CA	CE	1,070	2022	2008/ABZ
SONGS 3	CA	CE	1,080	2022	2008/ABZ
STP 1	TX	W	1,251	2027 LR pending	2007/TLG
STP 2	TX	W	1,251	2028 LR pending	2007/TLG
Vogtle 1	GA	W	1,169	2047 w/LR	2009/TLG
Vogtle 2	GA	W	1,169	2049 w/LR	2009/TLG

Selecting and developing data for comparison

All of the decommissioning cost estimates contain significant amounts of data. Differences in definition, format, and data organization require the exercise of great care in extracting and comparing data between studies done by different cost estimate providers. The general approach was to begin with comparisons between cost estimates done by TLG and then seek comparable data from the ABZ study for SONGS 2 and 3. All cost data was converted into common 2008 dollars assuming an annual rate of inflation of 3 percent. As comparison activities at greater levels of detail developed, the question of whether contingency is included or not included in various numbers and summations becomes an important detail.

How cost estimates are developed

A digression on how cost estimates are developed is useful here. Cost estimates by TLG and ABZ are developed “from the ground up” in many hundreds of individual lines items, each representing some particular task, e.g. *removing the reactor vessel*, or *property taxes*, that are grouped together into “activity” or “period” costs for the various phases of decommissioning. Each line item represents the estimator’s best estimate, based on historical experience or best available information, for the task being estimated, and typically involves multiple interrelated assumptions about the task’s scope,

difficulty, labor requirements, and time and equipment required to complete the task. For each of these line items, after the various direct cost elements (e.g. decontamination cost, removal cost, packing cost, disposal costs) have been developed and summed, the level of contingency to be applied to that individual line item is then determined based on the estimators' judgment, and added to the sum of the direct costs elements to give the total cost, including contingency, for that line item. All of the line items are then summed to give the total cost of decommissioning, including contingency. Each cost estimate provider has an elaborate proprietary computer model that provides a template for organizing this mass of data.

Each cost estimate provider, while producing the same net outcome, a nuclear power plant decommissioning cost estimate, uses different combinations of individual line items, slightly different definitions of detailed cost elements, and organizes the line items into similar but not identical phases of decommissioning activity. This diversity in line items, cost element definitions, and decommissioning phases by the different cost estimate providers poses an immediate challenge to direct comparison of decommissioning cost estimates. The proprietary computer models provide considerable power to summarize data in different ways, but the differences in definitions and practices need to be considered in every case, even within estimates by the same cost estimate provider. The presence or absence of contingency in one summarization vs. another also needs to be tracked rigorously.

Areas selected for comparison

After multiple comparative efforts, four quantitative comparisons are discussed in this report. These are:

- Total cost (including contingency)
- Annual cash flows (including contingency)
- LLRW burial volumes
- Staffing

A fifth area, schedule, was identified for qualitative discussion.

The "two unit site" comparison standard

In the interest of comparability, all the estimates were adjusted to be equivalent to the cost of decommissioning a two-unit site. For most of the sites, the estimates already exist for two units, and so no adjustment other than putting the costs into 2008 dollars was needed. In the case of IP 2, a single plant estimate, and PV, a three-unit site estimate, additional treatment of the cost estimate numbers was needed for "two unit site" comparability. These adjustments were as follows:

- The IP 2 estimate was doubled to be equivalent to a two-unit site estimate. While workable as a basis for comparison, the imperfections of this adjustment need to be understood. There are two other units at the Indian Point site in New York, one shutdown unit, Indian Point Unit 1 (IP 1), and one operating unit, Indian Point Unit 3 (IP 3). However, the IP 1 design is very different from IP 2 and the decommissioning cost study for IP 3 is not publicly available. Depending upon the decommissioning plan assumed for the site in development of the individual unit estimates, there might be some site related decommissioning costs that are not equally shared between the units. The amount of sharing between IP 1, IP 2 and IP 3 and whether it is more or less with

IP 2 is difficult to determine without access to the other studies. For the purpose of this comparison, the amount of any unequal sharing is assumed to be small compared to the overall cost estimate. To indicate this doubling of the single unit estimate, on charts and tables this is labeled as IP 2 (x2).

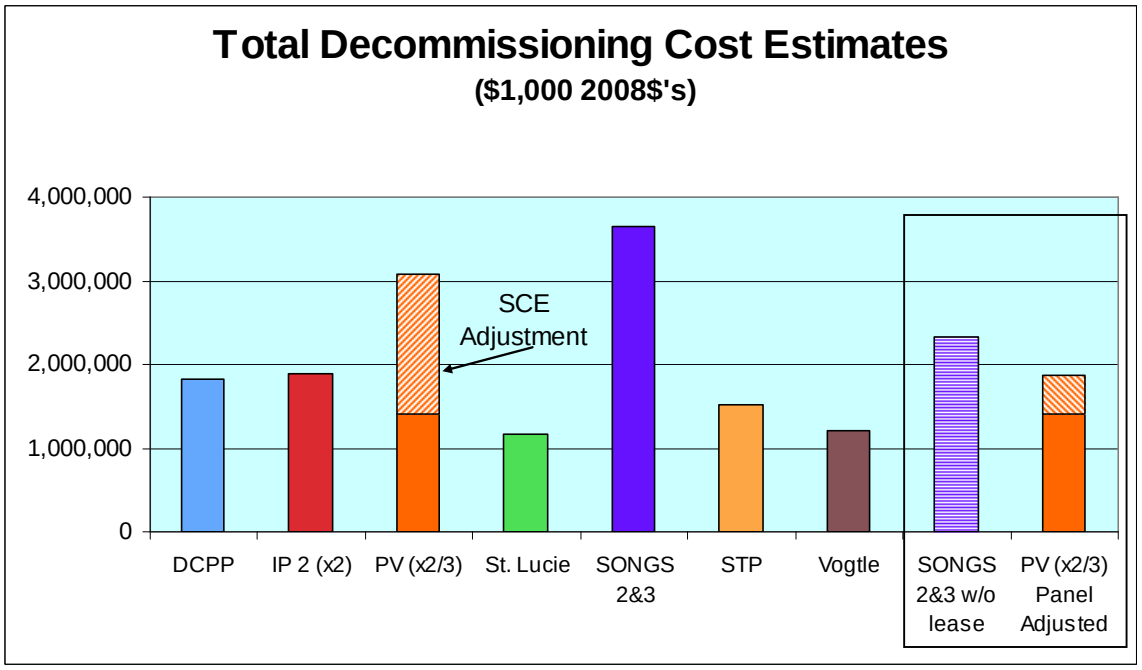
- The PV estimate was adjusted in two steps. The first step was to include in a total site decommissioning cost estimate the decommissioning costs of the water supply and treatment facilities, ISFSI, and other shared facilities. This information was all directly available in the PV decommissioning cost estimate report. After completing the total site estimate, the total was then multiplied times 2/3rds to reduce the total site cost for three units to be equivalent to a two-unit site. This approach of summing all costs for a site estimate then reducing to 2/3rds of the total eliminates any concern about unequal sharing between units and provides a reasonable basis for comparison. To indicate this fractional reduction in the total site cost estimate, on charts and tables this is labeled as PV (x2/3).

- The SCE adjustments to the PV estimate were not included in the PV cash flows used here for comparison.

Total Cost Comparison

Chart 5.1 shows the "two unit site" comparisons of the seven sites. The chart also includes information developed in the California comparison section of this report regarding PV and SONGS. Data for Chart 5.1 is included in Appendix D.

Chart 5.1 - Total Cost Comparison



The chart shows a range of estimates with the lowest being St. Lucie and the highest being SONGS 2&3. Setting aside SONGS 2&3, no estimate is less than $1 billion and no estimate is greater than $2 billion. The SCE adjustments to PV, discussed in section 4, more than double the estimator/operator provided cost estimate, and when included make it the second highest estimate on the chart. Explanations for the variation in the estimates in the $1 to $2 billion range include size (St. Lucie is the smallest), labor costs (DCPP and IP are higher wage rate areas), seismic design issues (DCPP and SONGS 2&3 in the Pacific Rim earthquake zone), contingency (DCPP and SONGS 2&3 use higher contingency than the other plants) and the presence of steam generators or other large components waiting to be disposed of as part of final decommissioning (St. Lucie has shipped its retired steam generators). Other issues include the timing of when estimates were done and site/design factors.

Adjustments to SONGS 2&3 and PV estimates

The two bars in the box on the right hand side of the chart illustrate adjustments to the SONGS and PV estimates. The details of these adjustments are discussed in section 4, but are summarized here.

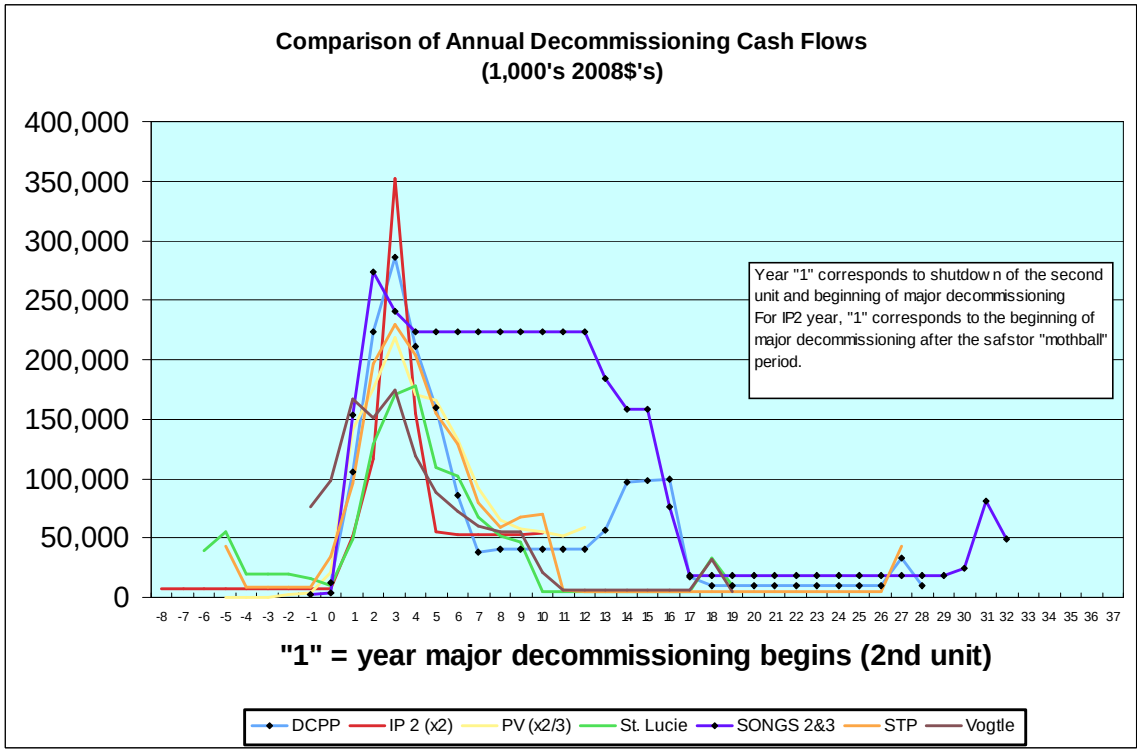
The “SONGS w/o lease” bar in the box represents the SONGS 2&3 cost estimate if the impact of the Navy Lease requirement on site restoration is eliminated. While still significantly higher than the other comparison sites, it does result in the SONGS 2&3 estimate being closer to the high-end estimates for the other sites. As suggested in section 4, SONGS 2&3, with its small site, represents a nearly unique set of challenges for decommissioning. The gap between the SONGS 2&3 estimate and other high-end site estimates is further reduced when the potential for eliminating the State Lands Lease requirement for removal of the off-shore cooling water conduits, a cost saving estimated approximately $50 million, is considered.

The “PV (x2) adjusted” bar in the box shows the elimination of one portion of the SCE adjustment as discussed in section 4. The result is then within the 1-2 billion dollar range of the other sites. Further revision of the SCE adjustments to the PV estimate provider cost estimate may take place in the future.

Annual Cash Flows

Chart 5.2 shows the annual cash flows for decommissioning of the seven sites. For best comparison, all cash flows have been converted to 2008 dollars and have been aligned such that year=1 on the chart corresponds to the final shutdown of the second unit at each site. Data for Chart 5.2 is included in Appendix D.

Chart 5.2 - Annual Cash Flows



The motivation for aligning the shutdown year of the second unit it to provide a comparison of the cash flows before, during and after the peak decommissioning effort for each site. To help distinguish the DCPP and SONGS 2&3 cash flows, the lines on the chart for them include a black diamond.

Decommissioning goes through several major phases with each phase offering instructive comparisons.

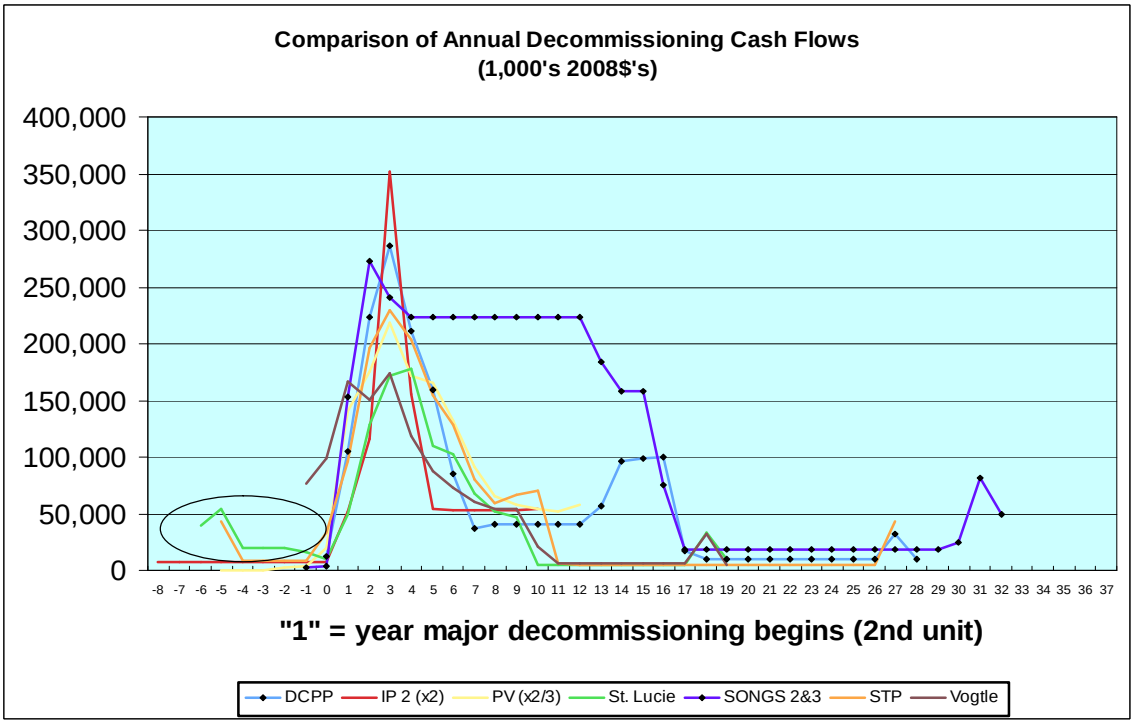
The five major phases considered in the report are:

- Pre decommissioning
- Major decommissioning
- Wet fuel storage
- Dry fuel storage, and
- ISFSI decommissioning

Pre-decommissioning phase

Chart 5.3 illustrates cash flows for the pre-decommissioning phase.

Chart 5.3 – Pre-Decommissioning Phase



Pre-decommissioning cash flows are not significant for DCPP, SONGS 2&3 and PV; however, they are important where:

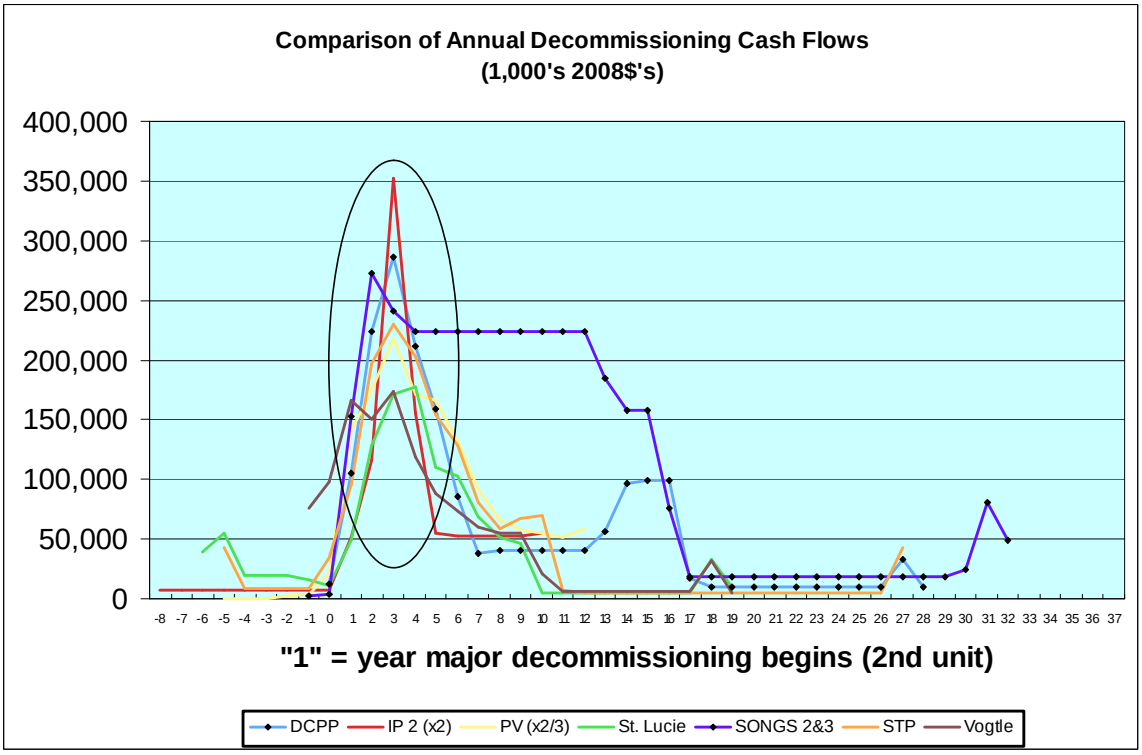
- There is a significant difference in the license for the first and second units at a site and some preliminary decommissioning work is done on the first unit (St. Lucie);
- The strategy is SAFSTOR and significant layup expenses and then a mothball period precede major decommissioning (IP 2); and
- A major project such as construction of an ISFSI is completed prior to major decommissioning, and is included as a decommissioning cost (STP).

DCPP, SONGS and PV units have shutdown dates within a year or less of each other, are not currently considering SAFSTOR, and already have constructed Independent Spent Fuel Storage Installations (ISFSIs).

Major decommissioning phase

Chart 5.4 illustrates the cash flows for the major decommissioning phase. This phase represents the bulk of the decontamination, dismantlement, and removal effort at all the plants and the bulk of the cost.

Chart 5.4 – Major Decommissioning Phase



The cost of this phase is driven by three main factors:

- The amount of material to be handled/disposed of;
- The staffing required; and
- Schedule.

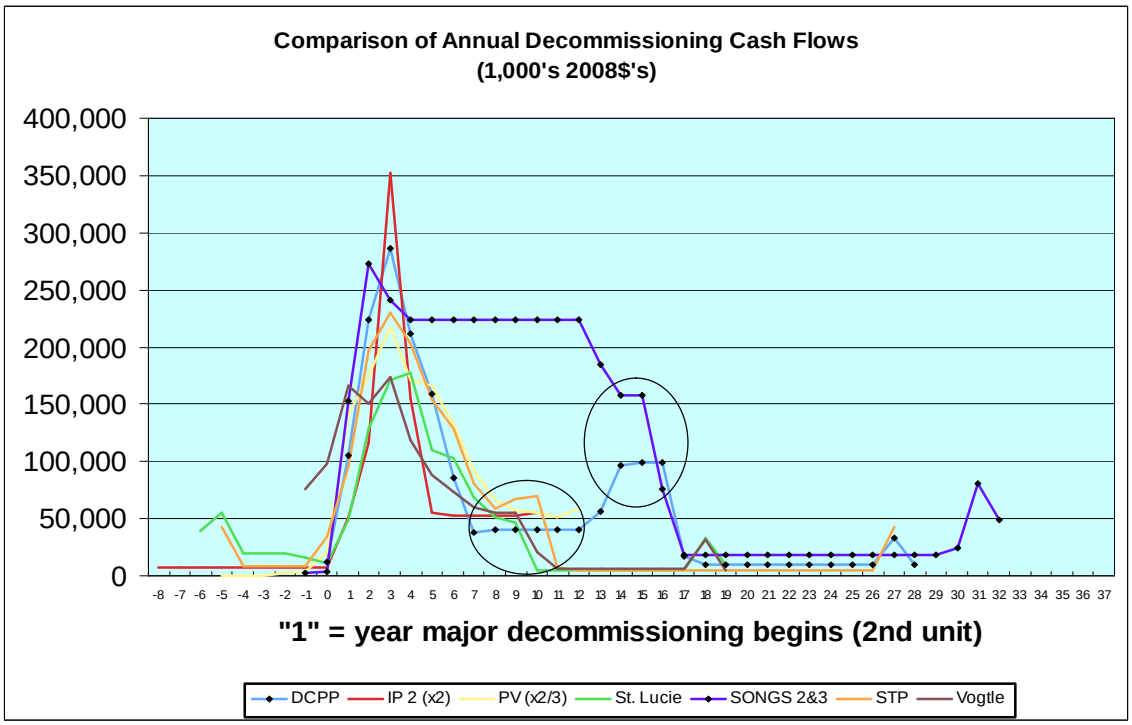
The shape of the expenditure curve is the same for all the sites with the exception of SONGS 2&3. There is a rapid ramp up that peaks around the third year, and then similarly declines. The size and width of the peak is driven by the factors noted above, each of which will be discussed in more detail later in this section of the report.

In the case of SONGS 2&3, the shape of the major decommissioning curve is very different due its unique site restoration requirements, e.g. the Navy Lease. There is a comparable rapid rise on the front edge of the curve, but then it levels off for a steady state period of approximately nine years before declining, leveling off again, and then finally declining again. This represents the majority, but not all, of the difference between SONGS 2&3 and the other site decommissioning cost estimates.

Wet fuel storage phase

Chart 5.5 illustrates differences in cash flows for the wet fuel storage phase that follows major decommissioning for most, but not all, of the sites.

Chart 5.5 – Wet Fuel Storage Phase



The two circled areas on the chart illustrate a major difference between the DCPP and SONGS 2&3 cost estimates and the cost estimates for the other sites (except IP 2 which will be discussed separately) and the differences are significant.

DCPP and SONGS 2&3 assume wet fuel storage periods of 12 years after shutdown. The other sites assume five years. This difference is clearest for DCPP, where, beginning in year seven, the decline in DCPP's cash flow becomes flat until rising again in years 13 and 14, when it levels off at a higher level for three more years then declines significantly.

The period for DCPP from year 7 to 13 represents a quiet phase in decommissioning when fuel is cooling in the wet fuel pool until it can be moved to dry storage. The annual expenses during this phase represent management and staff, including security, on site while the fuel cools. The rise in costs for the years 13 through 16 represent moving fuel out of the wet fuel pool into dry storage and site restoration work enabled by emptying the wet fuel pool.

A similar phase of wet fuel storage for 12 years is going on for SONGS 2&3, but the expense of that wet fuel storage is masked by the other site restoration work being performed due to the unique site restoration requirements. Evidence of the impact of the longer wet fuel storage period is provided by the interruption of the decline in the SONGS cash flow in years 14 and 15. Major site restoration work is tapering off in years 12 through 17, except for that precluded by wet fuel storage. After the wet fuel

pool is emptied, site restoration then proceeds until substantially completed. The major remaining on site activity is then dry storage of fuel until after all fuel is finally removed from the site by the DOE. After removal of the last of the fuel, the ISFSI is decommissioned and final restoration of the site in accordance with the Navy Lease is completed.

For the other sites, wet fuel storage for a minimum period of five years is assumed. For the cost estimate, this allows emptying out of the wet fuel pool and associate site restoration to proceed about seven years earlier than in the DCPP and SONGS estimates. The bulk of this shorter wet fuel storage period is masked by major decommission work, similar to the masking that is taking place at SONGS by the extended site restoration effort. However, as is the case with DCPP and SONGS, the tail end of the wet fuel storage period and site restoration effort can be seen in years 8 through 10 where there is a plateau in cash flow before declining sharply.

While the cash flow advantages of shorter wet fuel storage periods is obvious, the practical reality is the longer period may represent a more accurate picture of what will actually happen. The wet fuel storage period is determined by the cooling period required to meet heat load and radioactive dose limits in the licenses for dry casks. There is a general tradeoff between maximizing the economics of fuel in the reactor and minimizing the cooling period after being removed from the reactor. As you increase the one, you also generally increase the other.

The five year period commonly used in decommissioning cost estimates is based on a condition that fuel that has cooled at least five years is considered ready for the DOE to pick up as part of the Standard Contract.[25] As the DOE delay in performance continues, the role of wet and dry storage becomes increasingly significant for decommissioning, and the five-year period for decommissioning planning may be increasingly revisited. At the same time, there will be growing interest in cask designs for higher burnup fuel and ways to minimize the annual expenses associated with the decommissioning phase where major decommissioning is complete and sites are waiting to be able to move fuel into dry storage.

IP 2 does not directly have this issue in its decommissioning cost study because it assumes the DOE will perform during the SAFSTOR period before major decommissioning. Hence the cost estimate does not have any wet fuel pool storage expense during or after major decommissioning. This situation may change as the assumptions for DOE pick up continue to change.

<u>License termination after wet fuel storage</u>

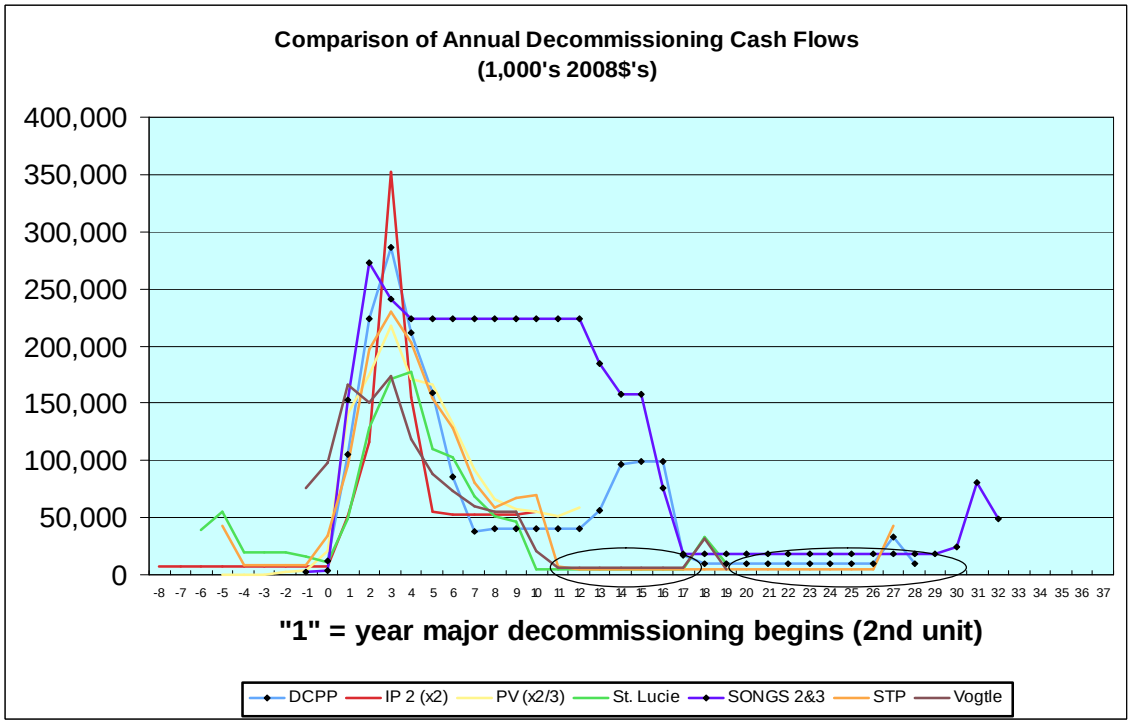
Termination of the Part 50 operating license for the reactor is generally desirable to eliminate the need for compliance with NRC regulations and oversight. However, the ability to terminate the Part 50 license will be determined by several factors, including whether the ISFSI has a separate Part 72 license. Even if the ISFSI has its own Part 72 license, there may be residual issues that could preclude termination of the reactor's Part 50 license.

[25] The Panel is not offering an opinion that fuel would have been accepted by the DOE after a five-year cooling period; only that this is one of the criteria in the Standard Contract.

Dry fuel storage phase

Chart 5.6 illustrates differences in cash flows for the period when fuel is in dry storage in an ISFSI. This period is after major decommissioning, and the bulk of site restoration is complete, and there is no fuel in wet storage.

Chart 5.6 – Dry Fuel Storage Phase



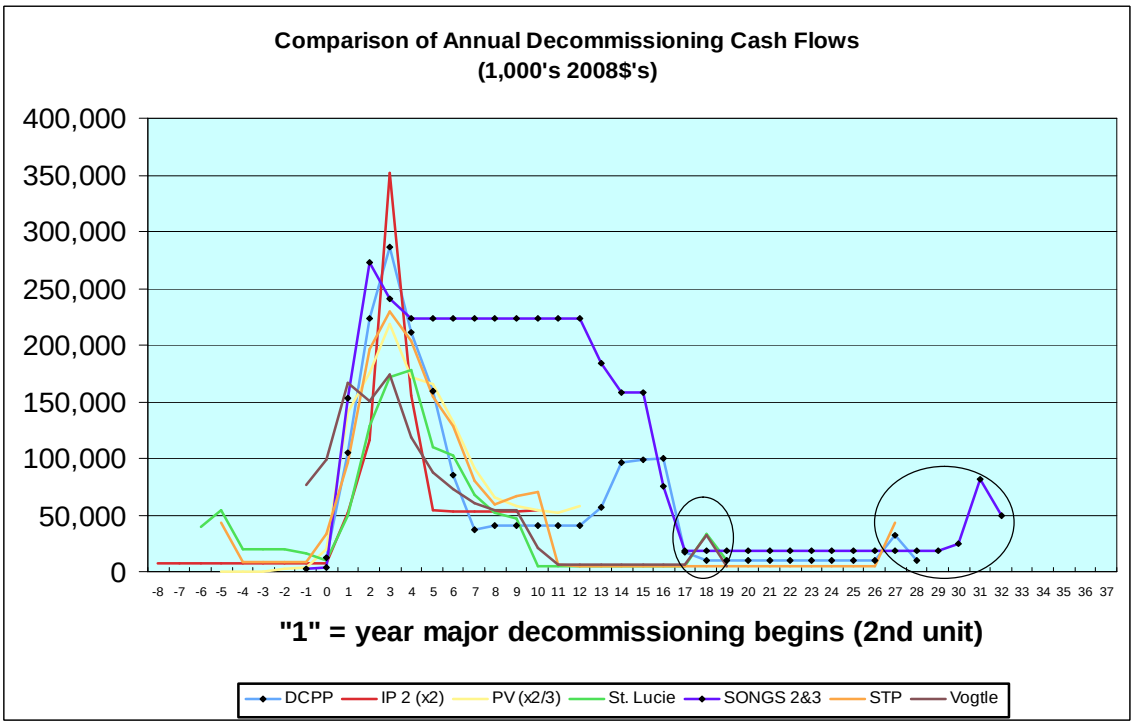
This phase is characterized by a major reduction in site staffing to the level required to provide administration, monitoring and security for the ISFSI. The storage of spent fuel in an ISFSI is a largely passive situation, and the staffing required for this storage method is small compared to the major decommissioning and wet fuel storage phases. The annual costs assumed in the St. Lucie, STP and Vogtle estimates are approximately the same, and are also very similar to the annual costs assumed at IP during its mothballed/SAFSTOR period prior to the commencement of major decommissioning. Annual costs for DCPP and SONGS 2&3 are respectively slightly and significantly higher than the other comparison plants.

The most significant point to be made regarding the dry fuel storage phase is the significant uncertainty in the assumed time. The length of time required for dry fuel storage will be determined largely by DOE performance, specifically when DOE starts to perform and at what rate. The effort by the current administration to cancel the Yucca Mountain project raises hard-to-resolve questions about the future of DOE performance, and suggests an extended period of time well beyond current assumptions for dry fuel storage at decommissioned reactor sites.

ISFSI Decommissioning

Chart 5.7 illustrates the final step in the site decommissioning process; the decommissioning and site restoration of the ISFSI after all spent fuel has been removed from the site.

Chart 5.7 – ISFSI Decommissioning



With the fuel having been securely packaged inside steel canisters during storage, the ISFSI itself should have little or no residual radioactive contamination.[26] ISFSI decommissioning is primarily the effort required for demolition of a very robust set of concrete structures/foundations.

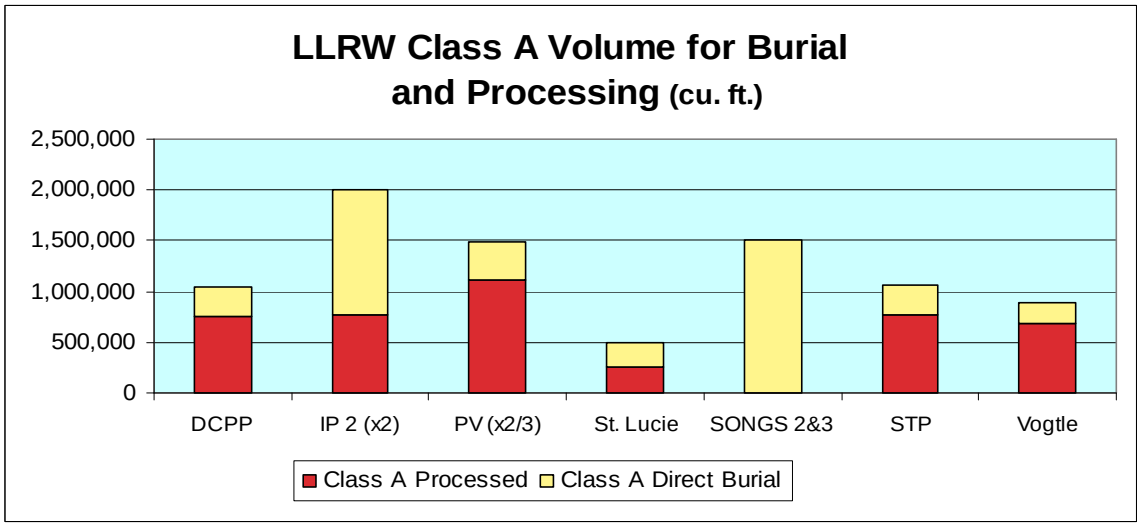
The SONGS 2&3 final site decommissioning costs include removal of offshore intake and outflow cooling water conduits for both units, an effort estimated at $50 million for both units together. This additional scope accounts for a large portion of the difference between the SONGS 2&3 and other site cost estimates.

[26] It is possible that part of the ISFSI concrete structure becomes activated during fuel storage. If so, this activation concrete will likely be disposed of as LLRW.

Waste volume

As indicated earlier, waste volume is an important factor in the decommissioning cost estimate. Chart 5.8 illustrates how the LLRW Class A volumes compare between sites. Data for Chart 5.8 is included in Appendix D.

Chart 5.8 – Waste Volume



The site totals for class A waste volume vary significantly. St. Lucie is lowest with 500,000 cu. ft. of material and IP is highest with four times as much, or 2,000,000 cu. ft. Three sites, DCPP, STP and Vogtle cluster in the 1,000,000 cu. ft. range. Total decommissioning cost (chart 5.1) varies in a similar manner to this chart, but notable exceptions are IP 2 and PV, which have waste volumes equal to or higher than SONGS 2&3.

Processing/conditioning is essentially the result of the cost of labor for sorting, decontaminating and otherwise reducing the volume of waste for burial vs. the cost of direct burial. Higher waste burial costs vs. labor costs motivate more effort for processing/conditioning. Some waste is more amendable to processing/conditioning than others.

IP 2's higher direct burial volume is related to its site soil contamination issues.

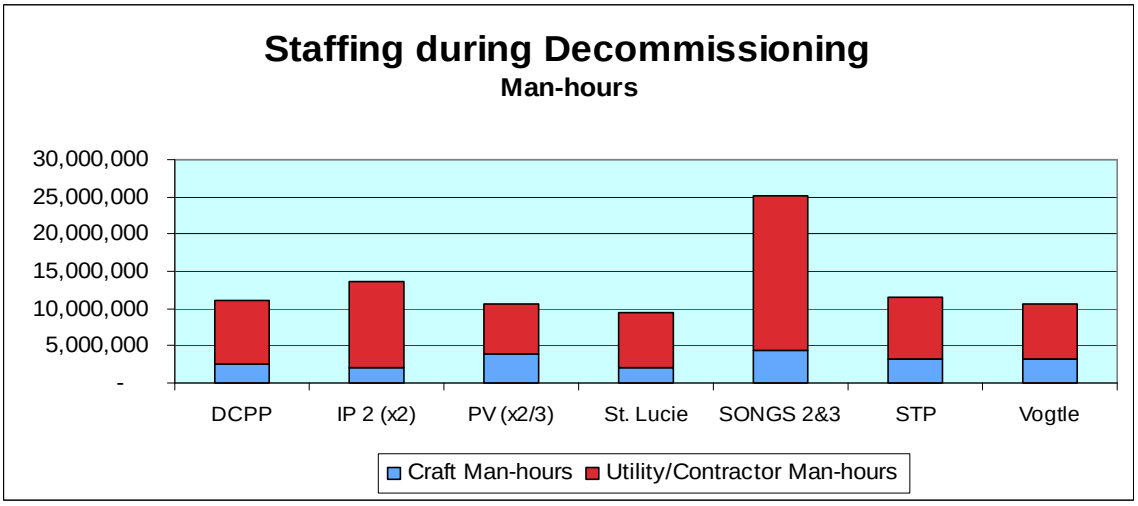
Generally, the processing/conditioning portion of the volume represents a slightly lower unit cost than the direct burial unit cost; hence the large volume of waste at PV, the majority of it addressed as processed/conditioned, does not drive the overall cost estimate higher in proportion to total waste volume. Variations in estimated costs for burial and processing/conditioning can increase or remove the advantage of using processing/conditioning.

As discussed in other parts of this report, higher waster burial costs drive decommissioning to consider more processing/conditioning, and lower waste burial costs drive toward more of a wholesale "rip and ship" approach.

Staffing

Staffing costs are also an important driver of decommissioning cost estimates, and the man-hour estimates in Chart 5.9 suggests a stronger correlation with total costs as seen in Chart 5.1. Data for Chart 5.9 is included in Appendix D.

Chart 5.9 - Staffing



Similar to the waste volume information, labor is broken into two main categories, craft and utility/contractor. Most of the sites use total labor in the range of 10,000,000 man-hours, with some being slightly higher or lower. SONGS 2&3 is distinctive with total labor at 25,000,000 man-hours, more than twice the range shown by the other plants.

The most important point with labor is the significant role played by existing utility/contractor staff in decommissioning cost estimates. In all cases, utility/contractor hours represent the majority, and in some cases (IP 2 and SONGS 2&3) a very large proportion, of the labor hours. A discussion of how these two labor categories are used in decommissioning cost estimates is instructive.

Decommissioning cost estimates divide tasks into two main categories; “activity” costs which are driven primarily by the scope of a task, e.g. remove reactor vessel, and “period” costs which are generally proportional to the duration of an activity, e.g. security during dry storage or project management during major decommissioning.

Craft man-hours are used primarily in support of activity costs. Utility/contractor man-hours are used for some activity costs, but dominate the period costs.[27] This allocation of labor suggests the dominant role that utility/contractor and period costs play in decommissioning cost estimates and the importance of schedule, the last topic in this section.

[27] Utility man-hours can include activity-related costs such as health physics support, security, and other common services used to support activities.

Schedule

Schedule is an important factor in both estimated and actual decommissioning costs.

All of the site cash flows, with the exception of SONGS 2 and 3, show similar schedules for major decommissioning. The explanation for SONGS 2 and 3 again is the Navy lease and State Lands requirement for full site restoration.

Given the significant role of “period” costs, preventing the extension of schedules is important in managing costs. An extension to schedule, even where there is no increase in “activity” costs, can materially increase the cost of a project. The relative “period” cost increase resulting from a schedule delay is also driven by the differences in “period” costs for different phases. A delay in the major decommissioning phase has a greater impact than a delay in the wet fuel storage phase, which is greater than the impact of a delay in dry fuel storage.

6. EMERGING RADIOLOGICAL ISSUES

Each historical decommissioning project faced unexpected radiological issues. At the Connecticut Yankee plant, for example, fuel from an early fuel failure had contaminated portions of the plant systems, making removal more difficult. At the Yankee Rowe plant, tritium and carbon 14 contamination of concrete prohibited plans to treat and reuse the concrete on site; instead the concrete was disposed of as LLRW. During the SONGS steam generator replacement, metal rebar used in the concrete containment walls was found to be radiologically activated due to the neutron flux from reactor operations.[28]

The Panel was asked to evaluate whether emerging radiological contamination issues could increase decommissioning cost, and if so, whether any steps could be taken to minimize such contamination in the future.

In addition to reviewing documents produced by the Owners, and other public documents, the Panel interviewed Gregory Maret, the Vice President for Decommissioning at the Yankee Rowe plant. During this interview, the Panel questioned the types of radioactive contamination present at Yankee Rowe, the methods utilized to mitigate that contamination, and the affect of contamination on decommissioning activities and costs.

Two radiological contamination issues merit discussion by this Panel. The first issue is tritium contamination. Tritium is a radioactive isotope of hydrogen that is created naturally in the atmosphere by cosmic rays from the sun. Tritium is also created as a byproduct of nuclear power. Tritium readily combines with oxygen to form tritiated water, and cannot be chemically separated from non-tritiated water. Similar to regular water, tritiated water readily diffuses into concrete.

Tritium is normally present in reactor coolant and spent fuel pool water. Tritium contamination must be considered by a licensee to terminate an NRC operating license, but such contamination can generally be left on site since tritium contamination does not typically form a large contributor to on site dose rates, and is not typically a substantial contributor to the dose analysis.[29] The EPA, however, not only has a lower dose limit than the NRC for tritium, but it also has concentration limits for ground and groundwater tritium contamination.

As a result of the small contribution of tritium to on-site doses, there is typically little risk from leaving tritium contamination on site (as long as the concentration is less than the EPA and NRC limits).

[28] Until SCE removed this rebar and tested the material, it was assumed for decommissioning purposes that neutron activation would be limited to the reactor vessel and internals, and structures directly surrounding the vessel.

[29] Tritium decays by emitting a low energy beta particle, which is simply an electron. Tritium is one of the least dangerous radionuclides because it leaves the body relatively quickly. See the EPA discussion on tritium at http://www.epa.gov/radiation/radionuclides/tritium.html, last updated on February 9, 2009.

The second emerging issue is carbon 14. Similar to tritium, carbon 14 is naturally occurring, but is also produced inside the reactor. Carbon 14 releases are a mix of organic carbon as well as a component of carbon dioxide. Carbon 14 is now one of the principal radionuclides in gaseous effluents from PWRs.[30]

At the Yankee Atomic plant, carbon 14 contamination of concrete derailed plans to treat and reuse contaminated concrete as on-site fill material. Instead, the contaminated material was shipped to a burial facility at increased cost.

Both tritium and carbon 14, while monitored, are not of primary concern during operation. After shutdown, however, they can become a factor in whether material is released as clean material or must be disposed of at a licensed LLRW facility. The effect of tritium and carbon 14 contamination is seen mostly in contaminated concrete and soil. Tritium, as a constituent of water, readily diffuses through concrete and soil. Utilities generally use special coatings on susceptible concrete surfaces to limit penetration of contamination into the concrete.[31] Once in the concrete, the tritium typically diffuses through the concrete until it reaches levels that approach equilibrium.

During operation, limited data is collected addressing the distribution of tritium and carbon 14 through concrete and soil generated from operation. Consequently, any additional data that can be collected regarding the distribution of these radionuclides will facilitate a more accurate estimate of decommissioning costs. The Panel advocates collection and use of such data where the opportunity is provided through routine maintenance and plant modifications.[32]

[30] NRC Regulatory Guide 1.21, Measuring, Evaluating, and Reporting Radioactive Material in Liquid and Gaseous Effluents and Solid Waste, June 2009, Revision 2, at 15.

[31] The coatings are typically epoxy, and limit the penetration of contaminates into the concrete. In addition, they provide a smooth surface to assist in identification and cleanup of spills. The epoxy coatings have not been designed nor tested to completely eliminate the penetration of contaminates into the concrete. Such a system that would be capable of completely eliminating penetration of contaminates is not currently an economic option.

[32] An example of this opportunistic use of data is the recent steam generator replacement at SONGS. During this project, concrete and metal were removed from the containment structure, and were subsequently tested for the presence of radionuclides. Similar testing could be performed when other concrete or metal structures are disturbed as part of plant operation.

7. MINIMIZING FUTURE COSTS / UNCERTAINTY

The Panel identified actions that the Owners could consider to incorporate into future estimates that would reduce estimated costs, and/or minimize the uncertainty associated with decommissioning. The Panel acknowledges that planning on reduced costs, and executing the project for reduced costs are two distinct activities. As such, the Panel is not recommending that a to-be-developed technology be relied on in estimating future costs.

Minimizing Costs

The following are the items that the Panel determined could have the potential to reduce future decommissioning costs (reduce funding requirements).

- Operate the station to minimize end-of-life contamination levels and uncontained environmental releases (the Panel believes this is a fundamental of present / future plant operations and would require no additional actions beyond those required and monitored by regulatory agencies)

  The NRC has recently promulgated requirements related to this topic. As described by the NRC "The new 10 CFR 20.1406(c) states as follows:[33]

  (c) Licensees shall, to the extent practical, conduct operations to minimize the introduction of residual radioactivity into the site, including the subsurface, in accordance with the existing radiation protection requirements in Subpart B of this part and radiological criteria for license termination in Subpart E of this part.

- Consider potential mitigating actions if LLRW is expected to escalate at a rate substantially greater than labor or general inflation

  The basic premise of the suggestion is to consider if the methods selected for decommissioning are consistent with a relatively large LLRW price escalation rate that extends for many years. Simply stated, if low level waste escalates at a rate approximately twice the rate of labor or general inflation for multiple decades, there would be an increased incentive (benefit) to use additional labor and equipment to minimize the amount of waste produced.

  The Panel believes an example of this was the nuclear industry's response to historical increases in LLRW costs at rates greater than general inflation. The Panel believes that in response to this escalation rate there were greater efforts made by the industry to minimize the production of LLRW to manage the overall LLRW disposal cost. As noted by the NRC in NUREG-1307, Volume 14, Section A.3:

[33] The new regulations will take effect 18 months following publication in the Federal Register. This rule must also be reviewed by the Office of Management and Budget before publication.

"…Waste management costs at nuclear power plants are being reduced through the use of waste vendors and the Clive, Utah disposal facility. Also, closer attention to LLW management by power plant licensees has resulted in dramatic reductions of LLW being disposed of at the commercial LLW burial sites. Since publication of NUREG/CR-0130 and NUREG/CR-0672, the average annual LLW volume disposed of by nuclear power plants has decreased by an order of magnitude. This volume reduction has been achieved through a combination of increased efforts to minimize the volume of LLW generated to begin with and increased use of waste vendors to reduce the volume of disposed LLW. The trend of utilizing waste vendors and the Clive, Utah disposal facility by licensees of operating nuclear power plants is also now being observed at nuclear power plants being decommissioned…"

Similarly the industry (via EPRI), in response to increased costs and / or lack of available disposal facilities, has taken the initiative to consider the means of reducing Class B and C waste, i.e., EPRI Report – "Waste Class B/C Reduction Guide", Report 1015115, November 2007.

- Consider incorporating likely economies of scale in decommissioning a multi-unit station

  The Panel believes that during the course of decommissioning a two-unit nuclear station there are certain activity costs that could likely be shared between the units. Examples of these types of activities include procedure development, waste packaging analysis, design of specialty waste packages, and some program management functions.

- Consider adjusting "actual experience" costs (those which would likely include contingency) to be consistent with the cost estimate contingency model

  The Panel suggests that when incorporating actual experience costs into the decommissioning estimate, the estimator consider whether the actual experience cost likely includes all or some part of contingency. If it does, the estimator should determine if it appropriate to remove some or all of the contingency cost to be consistent with the decommissioning estimates contingency model.

- Consider the potential impact based on a 20-year license renewal

  If the station receives a 20-year license renewal and operates for an additional 20 years, decommissioning could be deferred at least 20 years. This deferment could result in lower or higher funding requirements, depending on the exact assumptions used. In general there are three principal cost estimate drivers impacted by license renewal. These include:

  - Timing of decommissioning (costs are deferred approximately 20 years, assuming that the same decommissioning strategy is selected)
  - Increased activation levels in the reactor and reactor internals (which would be expected to modestly increase reactor disposition cost)
  - Spent fuel storage costs (which could increase or decrease depending on expected DOE performance)

The principal impact on funding is driven by forward-looking economic projections, including inflation rates and earnings on trust fund balances. Assuming that after-tax earnings on trust fund balances measurably exceed inflation rates, it is reasonable to assume that a 20-year license renewal would result in a lower net present value decommissioning cost.

- Consider the potential impact on recovery of spent fuel damages

  Many owners have pursued legal action to collect damages associated with managing spent fuel, based on the DOE's non-performance in accepting spent fuel from the station. Since decommissioning cost estimates include the cost of managing spent fuel after shutdown, with DOE's delay in accepting spent fuel, there is some likelihood that some of the post-shutdown spent fuel costs will be recovered from the DOE. In considering the effect of collecting damages the Panel recognizes that:

  - There is currently no certainty that damages will be collected, nor what part of post-shutdown fuel storage costs will be determined to be caused by the DOE's failure to start accepting spent fuel;
  - There is currently no certainty in the time between when damages are incurred and damages collected;
  - The NRC requires that the owner manage spent fuel, regardless of DOE performance, and, at present, demonstrating funding for this management approximately five years prior to shutdown without reliance on litigation recovery; and
  - Utilities will incur litigation costs or costs associated with auditing claims under settlements.

  If recovery of costs from the DOE is considered, the Panel believes that this recovery should be reflected in the schedule of expenditures and collections analysis, not in the decommissioning estimate.

<u>Minimizing Uncertainty</u>

The following are the items that the Panel determined could have the potential to reduce the uncertainty with future decommissioning costs. Reducing uncertainty may or may not reduce decommissioning funding requirements.

- As opportunity allows, identify the extent of radionuclides that could impact NRC license termination criteria, and the extent of contamination that could be below NRC license termination criteria, but could be impacted by state standards or similar requirements. This activity is somewhat consistent with a recently promulgated requirements related to this topic. As described by the NRC

  "The amended 10 CFR 20.1501(a) and (b) state as follows: [34]

[34] The new regulations will take effect 18 months following publication in the Federal Register. This rule must also be reviewed by the Office of Management and Budget before publication.

(a) Each licensee shall make or cause to be made, surveys of areas, including the subsurface, that

(1) May be necessary for the licensee to comply with the regulations in this part; and

(2) Are reasonable under the circumstances to evaluate --

(i) The magnitude and extent of radiation levels; and

(ii) Concentrations or quantities of residual radioactivity; and

(iii) The potential radiological hazards of the radiation levels and residual radioactivity detected.

(b) Records from surveys describing the location and amount of subsurface residual radioactivity identified at the site must be kept with records important for decommissioning"

- Solicit and Incorporate input from site security in developing a site-specific decommissioning security model

  Site security is expected to have a substantial cost impact on decommissioning, including both the direct costs associated with security department personnel and equipment, and the indirect costs associated with implementing a security program such as, employee / contractor screening and delays caused by hindrances in freely moving equipment and material.

  The Panel understands that certain security related information is protected as "Safeguards" information by NRC regulation and is not allowed to be publicly disclosed. The Panel is not suggesting that Safeguards information be shared with estimators or be disclosed to the public.

- Minimize stored LLRW to be disposed of during decommissioning

  Storing LLRW generated during the course of operations, and planning for its disposal decades later during decommissioning, will increase the uncertainty of estimated future decommissioning costs. Disposing of this waste will minimize the uncertainty of disposing of waste in the future (particularly where LLRW is projected to escalate at an annual rate measurably greater than the rate of general inflation).

  The Panel recognizes that certain waste packages may require substantial efforts to transport, and could be more cost-effectively transported during the course of decommissioning. However, the benefit of lower transport costs needs to be considered in relation to projected cost of waste disposal.

8. CONTINGENCY

Every cost estimate involving future activities must consider risk. Risk, or uncertainty, is manifested in several forms:

1. Performance risk, or that risk associated with completing the defined scope of activities within the allotted schedule and cost;
2. Scope risk, or that risk that the defined scope did not consider all activities required to be performed to complete the project;
3. Regulatory risk, or the risk that the rules governing performance of the work can change; and
4. Financial risk, or the risk that one or more of the financial assumptions used for the funding analysis was incorrect.[35]

All of these types of risk have resulted in added costs in recent decommissioning projects, and must be considered for future projects.

ABZ and TLG decommissioning estimates typically address only performance risk.[36] Both ABZ and TLG assign contingency on a line-by-line basis, with each specific value calculated based on the uncertainty associated with each specific activity. For example, where an activity is routine, and its costs well understood, the estimator would assign a lower contingency value. Where an activity is not well understood, the estimator would assign a higher contingency value.

Overall, the performance risk contingency typically included in decommissioning estimates by ABZ and TLG range from approximately 17 percent to 22 percent. The SONGS and DCPP 2008 estimates were performed with the overall contingency targeted to be 25 percent. This Panel understands that this contingency value was based, in part, on the contingency value normally used by the NRC, and was intended to capture performance risk.[37]

Contingency for performance risk is expected to be fully expended during the project. Examples of activities for which contingency dollars could be used include:

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[35] Financial assumptions include escalation rates for each category of costs, trust fund return rates (fixed and equity), allocation of trust funds, assumptions concerning tax treatment of trust funds including corporate tax rates, and projected cash flow for decommissioning expenditures.

[36] While generally correct, there are some important caveats. First, the ABZ estimates allow for some minor, yet undefined, increase in scope. Second, both the ABZ and TLG estimates assign greater contingency to an item where the activities required to perform the item are not well understood, such as reactor vessel segmentation. Finally, some estimates include a separate factor to account for non-performance risk, including the types of risk discussed in this report.

[37] U.S. commercial utilities are required to report to the NRC at least every two years the status of funding for decommissioning. This report must include certification that financial assurance of at least the amount provided in 10 CFR 50.75 is being provided. The amount identified in 10 CFR 50.75 is based on the type and size of the reactor, and is provided in 1986 dollars and adjusted based on factors provided in NUREG-1307. This amount for financial assurance includes 25 percent contingency on all costs. Thus, the minimum decommissioning funding assurance required by the NRC by design includes 25 percent contingency.

- Recontamination of a work area
- Weather delays
- Unanticipated work difficulty associated with confined spaces
- Equipment or tool breakage
- Difficulty with waste packaging
- Personnel turnover
- Schedule slippage due to resource conflicts

This same approach is taken with Federal agencies. The DOE Cost Estimating Guide, for example, state that:

> "Cost for contingency is added to estimates in preparation for undefined future events within scope of a project or specific endeavor but not part of the negotiated contract. Because contingency is not put on contract, it is controlled by the Government and cannot be developed through detailed estimate. If it were possible to estimate a cost in detail, it would become part of the project scope and would not be considered a contingency."[38]

The second type of risk, scope risk, results from changes in required decommissioning activities that were not foreseen by the estimator. The estimator develops the estimate based on current plant drawings and understandings, and as a result, the estimate may not reflect the actual configuration of the site, including the distribution of radionuclides on the site. Numerous utilities, including SCE and Yankee Atomic, were faced with increase decommissioning costs when underground items were discovered that were previously unknown. These underground items can include abandoned pipes, cables, or structures that were never added to site drawings. Underground items can also include waste or other debris that was buried during construction or early operation and subsequently forgotten. Removal of these previously unknown items leads to unexpected costs and delays in previously planned work.

Other ground-related issues can also include previously unknown or unidentified contamination, both radiological and hazardous but non-radiological. Several utilities have identified soil contamination as a result of previously unknown plant leakage. For example, after all major structures were demolished and removed from its site, Yankee Atomic discovered that over 100 million pounds of soil more than anticipated had to be treated or removed from its site. This unexpected change in site conditions was estimated to add an additional seven months to the decommissioning schedule.[39] Similarly, when decommissioning the SONGS unit 1 power plant, SCE found water contaminated with tritium under the

[38] "Cost Estimating Guide for Program and Project Management, US Department of Energy, DOE G-430.1-1X, April 2004 at 38.

[39] United States of America, Federal Energy Regulatory Commission, Order Accepting for Filing and Suspending Proposed Revisions to Wholesale Power Contract and Establishing Hearing and Settlement Judge Procedures, Docket No. ER06-249-000, Issues January 21, 2006.

reactor containment structure. Cleanup of this water required removal and disposal of soil. This effort was not included in previous estimates since the existence of this contaminated water was not known.

Estimating the schedule for decommissioning can be just as challenging as the scope. Connecticut Yankee's decommissioning efforts were delayed several years to obtain a construction permit for its dry cask storage facility. The town of Haddam had refused the request for a building permit, which was ultimately decided in Connecticut Yankee's favor by the courts. This delay was not considered in the decommissioning cost estimate.

The third type of risk, regulatory risk, results from the inability to accurately predict the precise regulations that will be applied to decommissioning at some future date. The estimator determines costs based on an evaluation of what activities would be required to perform the necessary work under today's regulations. Costs associated with compliance with some future, unanticipated, and unknown changes in regulations are not considered within the estimate.

The last type of risk, financial risk, results from the inability to accurately forecast financial variables, including escalation, trust fund rate of returns, and taxes.

Utilities mitigate these risk types in several ways, including:

1. Use of performance risk contingency;
2. Conservative assumptions for cost escalation and fund earnings rates;[40] and
3. Periodic reassessment of costs.

The Panel believes that such mitigation is reasonable. The Panel also understands that PG&E argued in the last proceeding that a different contingency is appropriate for DCPP as compared to SONGS due to the lower risk of scope changes at the SONGS site as a result of the SONGS lease requirement to remove all material from the site.[41] The Panel agrees that the risk faced by the two utilities is not identical, and finds it reasonable that difference contingency percentages be used at both sites.

[40] For example, in 10 CFR 50.75, the NRC requires utilities using an external sinking trust or a prepaid fund to limit the assumed real growth rate to two percent per year, unless a higher rate of return has been specifically authorized by a rate making authority.

[41] While removal of more material from the SONGS site reduces the risk that the scope of activities could increase to include more material, it also raises the risk to SCE associated with changes in burial cost or regulations due to the larger quantity of LLRW.

9. COMMON ASSUMPTIONS

The Panel believes that although each of the stations is owned independently, there are assumptions that should be reasonably consistent between stations. Both SONGS and DCPP are located in the State of California, and have similar license expiration dates. The following decommissioning cost drivers should be similar, or differences clearly explained.

DOE Spent Fuel Performance – Significant assumptions regarding DOE performance should be consistent between the stations. This includes the projected starting date for DOE performance, and the annual acceptance rate to be used to determine individual allocations.

Waste management options and costs – Since both stations are located in California, it is reasonable to expect that the stations will likely have access to the same disposal facilities. As such, the estimated unit rates for waste disposal should be consistent in future estimates.

Severance costs – Since both stations are located in California, it is reasonable to expect that the stations will be subject to the same state employment laws. As such, it should be reasonable to assume that if mandatory severance costs are applicable to one station, they will be applicable to the other station. The Panel recognizes that determining projected severance costs may be based on owner-specific assumptions, and therefore, there may still be variation in the calculated severance costs.

Federal and State "End-State" acceptance criteria - The Panel recognizes that there are multiple layers of criteria necessary to complete the decommissioning process, and that for two stations both located in California they would likely be subject to many, but not all, of the same criteria. If the criteria were to be considered to consist of three layers, federal, state, and site-specific, the following would be the basis for common assumptions:

- The NRC's and Environmental Protection Agency's (EPA's) requirements could be considered the first "common" layer. Typically this is interpreted as meeting a release standard of no more than 25 mrem / year TEDE (Total Effective Dose Equivalent) considering ALARA, managing the spent fuel until transfer to the DOE, and complying with the EPA groundwater standard. It is generally recognized that if most (but not all) of the radioactive material produced as a result of plant operation is removed, than the NRC's and the EPA's release requirements can be satisfied.
- The second layer would be the State of California and its agencies' requirements. These could be considered state requirements associated with site restoration. These requirements, specifically an interpretation of specific "acceptance" criteria, are less obvious to the estimator, and may require substantial judgment in defining the criteria decades before decommissioning. It is these criteria that may have substantial commonality between the two California stations. The Panel recognizes that these criteria may be inconsequential if site-specific requirements (SCE lease with the U.S. Navy) exceed the state requirements.

- The third layer (also related to site restoration) would be local and other owner-specified decommissioning requirements / desired actions included within the decommissioning funding basis. These requirements would be expected to be unique to each station. For the circumstance of SCE this could include the activities and costs necessary to terminate the lease.

Share existing "actual" decommissioning-related activity performance and cost data – The Owners should consider sharing their decommissioning-related activity performance and cost data, particularly information which they believe is relevant in estimating future decommissioning costs. Examples of relevant data may include:

- Waste package densities (achieved or achievable);
- Production rates for special dismantling activities (reactor internals);
- Man-hours to package large components; and
- Experience in the use of alternate waste disposal sites.

The Panel recognizes that actual data may be proprietary and is not advocating the public disclosure of confidential and commercially sensitive materials.

10. COMMON FORMAT

The objective of this task was to suggest a common format for the preparation of decommissioning cost estimates that would permit greater transparency and comparability.

Greater transparency and comparability of decommissioning cost studies can be achieved by improving the usage of the existing decommissioning cost study formats in a common summary format.

Two important considerations drove the Panel's approach of improving usage of the existing cost studies for a common summary format.

- The Navy and State Land Leases have unique impacts on the SONGS 2&3 decommissioning cost estimates. In comparison with other U.S. nuclear plant cost estimates examined in this Report, SONGS 2&3 is an outlier in terms of waste volume for disposal, labor required to complete the work, and total cost. Comparison of selected elements is possible and desirable, but the unique aspects of the SONGS 2&3 decommissioning cost estimates require special attention in any comparison.
- Cost estimators use proprietary decommissioning cost models to develop their cost estimates that have differences at all levels of the models. The results are the same, a nuclear power plant decommissioning cost estimate, but absent significant and expensive changes to these models, a common model output format reveals itself as an impractical goal. These differences are not confined to just ABZ and TLG. Other suppliers of nuclear decommissioning cost estimates would have even greater difficulty in accommodating common model output formats.

As indicated above however, lack of a common format is not a fundamental obstacle to greater transparency and comparability, and given the unique aspects of the decommissioning challenge at SONGS 2&3, a common summary presentation format best addresses the objectives of the task and the complicating issues.

Common Summary Format

As suggested in the U.S. comparison section of the report, the decommissioning cost estimates provide tremendous amounts of information. The challenge is to understand and extract the most useful and pertinent information. To this end the Panel recommends development of a Common Summary Format by the Owners that is organized into two parts, the first dealing with estimate assumptions and the second dealing with estimate results.

Specific recommendations are included in section 11 and a sample format is offered in Appendix E.

In the comparison of DCPP and SONGS 2&3, if cost estimate information is developed for SONGS 2 and 3 without the Navy and State Lands Lease requirements, that cost estimate information should be included in the Common Summary Format.

11. RECOMMENDATIONS

The Panel's review of the SONGS 2&3 and DCPP estimates did not identify significant issues that were unreasonable given the estimate assumptions and knowledge in 2008. Having said that, the Panel does have recommendations for the next time these estimates are updated, for SCE's adjustments to the PV estimate and other nuclear decommissioning related issues. These are:

1. Actual data should be used, where appropriate, as a basis for estimated costs. Actual data, however, should be reviewed to remove any embedded contingency and preclude unnecessary contingency.
2. Plant security should be involved with the development or review of the security assumptions and costs used in the decommissioning cost estimate, to ensure that the costs are appropriate for the projected security needs during decommissioning. This should not involve sharing of Safeguards information with estimators or the public.
3. The Owners should avail themselves of every opportunity to obtain volumetric contamination or activation data with which the decommissioning cost estimate contamination assumptions can be verified or modified. These opportunities are expected to include plant modifications and maintenance activities (similar to the recent steam generator replacements). Similarly, data from site monitoring should be used to confirm or adjust decommissioning assumptions. The results of these efforts should be reviewed in the NDCTP's and the effort adjusted depending upon the results. In addition, the Owners should follow industry activities with respect to hard-to-detect nuclides, including tritium and carbon 14, and update the estimates as additional industry knowledge and experience is gained.
4. The Owners should consider sharing decommissioning activity performance and cost data, where practical, and where the sharing does not violate confidentiality or concerns on commercially sensitive data. The data can also be provided in a form that protects those concerns, if practical.
5. The Owners should consider and use common assumptions where appropriate. The Panel suggests that these assumptions include:
    a. DOE performance;
    b. State requirements for severance payments;
    c. State requirements for site restoration; and
    d. Alternatives and pricing for LLRW burial.
6. The Owners should consider and agree on a Common Summary Format (Summary) for use in the next NDCTP that includes decommissioning cost estimate assumptions and results.
7. The Panel recommends that assumptions in the Summary be organized into categories, to include:

a. Common assumptions from recommendation 5;

b. Extent of site and building contamination; and

c. Low-level radioactive and hazardous waste anticipated to be present on site at the start of decommissioning.

8. The Panel recommends that results compared in the Summary include:

    a. Craft and non-craft labor hours, total, and by period;

    b. Security labor hours, total, and by period (non-safeguards);

    c. Average craft, non-craft, and security labor rates;

    d. LLRW handled, and removed from site;

    e. Clean waste handled, and all waste removed from site; and

    f. Major “activity” and “period” costs that are comparable between the estimates.

9. The Panel recommends that the Commission consider requesting that the next SONGS 2 and 3 cost estimate quantify the increased cost associated with the Navy lease above that required for site restoration comparable to that assumed in the DCPP estimate. The Panel understands that this effort may have considerable added cost.

10. The SCE adjustments to the PV estimate for waste volume should be reviewed and corrected, if submitted again.

11. The SCE adjustments to the PV estimate for large component removal, contingency, and spent nuclear fuel should be fully explained each time they are used.

12. The panel has concluded that it is reasonable for PG&E and SCE to use different contingency values to reflect the different risks faced at both sites, and that the values used for both estimates are not unreasonable.

12. ACKNOWLEDGMENTS

The Panel and the report have benefited significantly from the high level of cooperation from representatives from DCPP, SONGS and PV. Information requests and phone calls were treated thoughtfully and expeditiously. Coordination and support for the site visits and related interviews with technical staff was excellent.

References used by the Panel have been included in Appendix F, and comments provided to the Panel and the Panel's responses provided in Appendix G.

Literally dozens of people at each site have contributed to the Panel's efforts and this report. The role of SCE as the contracting representative for the utilities and also as the lead owner for SONGS and the coordinator for PV has been particularly appreciated.

We ask that Robert Bledsoe and Jorge Morales of SCE, Hal Carden and Rob O'Sullivan of PG&E, and Matthew Benac and Steven Peace of APS, please accept our appreciation and share that appreciation with the others in their organizations.