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Molly C. Dwyer
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October 21, 2019

No.: 19-72670
Short Title: Public Watchdogs v. USNRC

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NO. _____

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

In re PUBLIC WATCHDOGS

PUBLIC WATCHDOGS,

Petitioners,

v.

UNITED STATES NUCLEAR REGULATORY COMMISSION,

Respondent.

On Petition for Writ of Mandamus to the United States Nuclear Regulatory Commission

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EMERGENCY PETITION FOR WRIT OF MANDAMUS

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CORPORATE DISCLOSURE STATEMENT

Pursuant to Federal Rules of Appellate Procedure and 26.1 and Circuit Rule 21-3, Public Watchdogs states that it is a nonprofit organization under 26 U.S.C. § 501(c)(3). It does not have any parent corporations and there are no public corporations that own 10% or more of its stock.

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INTRODUCTORY STATEMENT OF RELIEF SOUGHT

"Although filibustering may be a venerable tradition in the United States Senate, it is frowned upon in administrative agencies tasked with protecting human health." *In re Pesticide Action Network North America, Natural Resources Defense Council, Inc.*, 798 F.3d 809, 811 (9th Cir. 2015). Here, Public Watchdogs seeks a writ pursuant to 28 U.S.C. § 1651 compelling a recalcitrant Nuclear Regulatory Commission ("NRC") to immediately suspend decommissioning operations at San Onofre Nuclear Generating Station ("SONGS") Units 2 and 3 until it has issued a reasoned decision on Public Watchdog's petition now pending under 10 C.F.R. § 2.206 ("2.206 Petition").[1]

As part of the ongoing decommissioning of SONGS Units 2 and 3, Licensees Southern California Edison Company ("Edison") and San Diego Gas & Electric Company (collectively, "Licensees") are in the process of burying hundreds of tons of deadly spent nuclear fuel a mere 108 feet from one of California's most populated public beaches, within a tsunami inundation zone, surrounded by active fault lines, in canisters

[1] The 2.206 Petition and accompanying exhibits are included at Addendum ("Add.")1 – 1553.

that are damaged, defective, and not properly designed to serve their intended purposes. What's more, the NRC's various actions permitting the implementation of Licensees' decommissioning plan at SONGS are based on unreasonable and fundamentally flawed assumptions that: (1) the United States Department of Energy ("DOE") will begin accepting and removing the spent nuclear fuel from SONGS in 2024 or 2028; (2) all of the spent nuclear fuel currently being buried at SONGS will be permanently removed from the site by 2049; and (3) the SONGS site will be restored to a condition that is acceptable for unrestricted use by 2051. In fact, no central repository for permanent storage of spent nuclear fuel exists in the United States, there is no viable plan to open such a permanent repository, and the DOE undoubtedly will not begin accepting spent nuclear fuel for permanent storage from SONGS or any other nuclear generating station in 2024, 2028, or any other time in the foreseeable future. As the United States Court of Appeals for the District of Columbia observed years ago: "At this time, there is not even a prospective site for a repository, let alone progress toward the actual construction of one." *New York v. Nuclear Regulatory Com'n.*, 681 F.3d 471, 747 (D.C. Cir. 2012).

By ignoring the manifold safety hazards posed by Licensees' decommissioning operations and permitting Licensees to implement their decommissioning plan based on the arbitrary and unreasonable assumption that spent nuclear fuel will be stored at SONGS only temporarily, the NRC has abdicated its paramount responsibility to protect public health and safety. Every eight days, Licensees are able to transfer more spent fuel into a new canister and bury it at SONGS. Absent relief from this Court, Licensees will continue their aggressive burial schedule during the NRC's consideration of the 2.206 Petition, demolish the only wet storage at SONGS, and create a substantial risk that buried canisters—which will remain in the ground indefinitely—will fail and release deadly radioactivity into a highly populated region. All this before the NRC ever reaches the merits of the 2.206 Petition. Southern California should not be allowed to burn while the NRC fiddles. Immediate mandamus relief is warranted.

ISSUE PRESENTED

Public Watchdogs has filed a 2.206 Petition with the NRC seeking an immediate halt to the movement and burial of spent nuclear fuel at SONGS. Unless the NRC temporarily suspends decommissioning, all of

this highly radioactive material will be buried before the NRC or this Court considers the merits of the 2.206 Petition. Should this Court issue a writ of mandamus to the NRC, thereby protecting its jurisdiction over the dispute?

JURISDICTION AND VENUE

The Court has jurisdiction to issue the requested writ pursuant to the All Writs Act, 28 U.S.C. § 1651, the Hobbs Act, 28 U.S.C. § 2342, and the Administrative Procedures Act, 5 U.S.C. §§ 555 and 706.

The All Writs Act authorizes federal courts to "issue all writs necessary or appropriate in aid of their respective jurisdictions . . . ." 28 U.S.C. § 1651(a). This broad grant of authority extends to situations, such as here, in which "future review may be jeopardized." *Potomac Elec. Power Co. v. ICC*, 702 F.2d 1026, 1032 (D.C. Cir. 1983), *supplemented by* 705 F.2d 1343 (D.C. Cir. 1983) (ordering agency to issue decision by date certain). While the All Writs Act is not an independent grant of jurisdiction, it nonetheless permits action "incidental to the courts' jurisdiction to review final agency action." *F.T.C. v. Dean Foods Co.*, 384 U.S. 597, 603 (1966). The paradigmatic *Dean Foods* situation is one in which an agency slow-plays a petitioner and renders its requested relief

moot through inaction. This tactic will not do, as this Court has noted: "Because the statutory obligation of a Court of Appeals to review on the merits may be defeated by an agency that fails to resolve disputes, a Circuit Court may resolve claims of unreasonable delay in order to protect its future jurisdiction." *Confederated Tribes of Umatilla Indian Reservation v. Bonneville Power Admin.*, 342 F.3d 924, 930 (9th Cir. 2003) (quoting *Telecomm. Research & Action Ctr. v. FCC*, 750 F.2d 70, 76 (D.C. Cir. 1984)). Just such a situation is present here.

Under the Hobbs Act, 28 U.S.C. § 2342(4), the Courts of Appeals have original jurisdiction to review certain licensing decisions of the NRC. *See Fla. Power & Light Co. v. Lorion*, 470 U.S. 729, 737 (1985) ("Congress intended to provide for initial court of appeals review of all final orders in licensing proceedings whether or not a hearing before the [NRC] occurred or could have occurred."). Because the NRC's ultimate decision on the 2.206 Petition is such a decision, this Court has jurisdiction to issue the requested writ in aid of its original jurisdiction.

The Administrative Procedures Act ("APA") directs agencies to conclude matters presented to them "within a reasonable time" and provides that a "reviewing court shall . . . compel agency action

unlawfully withheld or unreasonably delayed." 5 U.S.C. §§ 555(b), 706(1). And although these APA sections may not constitute an independent jurisdictional grant, "section 706(1) coupled with section 555(b) does indicate a congressional view that agencies should act within reasonable time frames and that court[s] designated by statute to review agency actions may play an important role in compelling agency action that has been improperly withheld or unreasonably delayed." *Telecomm. Research & Action Ctr.*, 750 F.2d at 77.

Venue is proper in this Court under 28 U.S.C. § 2343, as Petitioner has its principal office in California. And "[a]ny court that would have jurisdiction to review a final rule has jurisdiction to determine if an agency's delay is unreasonable." *In re A Community Voice*, 878 F.3d 779, 783 (9th Cir. 2017).

STANDING

Petitioner Public Watchdogs is a 501(c)(3) non-profit corporation that advocates for public safety by ensuring that government agencies and special interests (particularly in the public-utilities industry) comply with all applicable laws, including public-safety and environmental-protection laws. Petitioner has at least one member who lives within the

zone of exposure to a release of radioactive material from SONGS. Accordingly, Petitioner satisfies the standards for "organizational" standing. *Hunt v. Washington State Apple Advertising Comm'n*, 432 U.S. 333, 343 (1977), *superseded by statute on other grounds by* 102 Stat. 890, 29 U.S.C. § 2101, *et seq.* And given the facts recounted below, Petitioner is "imminently threatened with a concrete and particularized 'injury in fact' that is fairly traceable to the challenged action of the defendant and likely to be redressed by a favorable judicial decision." *Lexmark Intern., Inc. v. Static Control Components, Inc.*, 572 U.S. 118, 125 (2014).

FACTUAL BACKGROUND

I. Licensees' negligent operation of SONGS

In August 1963, Congress authorized the construction, operation, maintenance, and use of a nuclear power plant on approximately 90 acres of land located aboard Marine Corp Base Camp Pendleton. In May 1964, the United States of America granted Licensees an easement for the sole purpose of "construction, operation, maintenance and use of a nuclear electric generating station" at the Camp Pendleton site. Over the next fifty years, Licensees operated one or more of three nuclear electric generating units at SONGS. Licensees operated Unit 1 from

approximately 1968 until 1992, when they began its decommissioning process. Licensees operated Units 2 and 3 from approximately 1983 and 1984 (respectively) until June 12, 2013, when they submitted written certification to the NRC that they were permanently ceasing operation of those units.

Throughout its time as an operational nuclear power plant, SONGS was marred by numerous instances of poor safety and regulatory noncompliance, which ultimately contributed to the cessation of operations at the site. Licensees' compliance debacles included the backward installation of a 420-ton nuclear reactor vessel, and the unlicensed replacement of steam generators with defective substitutes. These failures were not mere technical violations—the unlicensed steam generators later malfunctioned and leaked deadly radioactive steam into the environment. These and other operational errors ultimately led Licensees to shutter SONGS and commence its decommissioning.

II. Licensees' fundamentally flawed decommissioning plan

On September 23, 2014, Licensees submitted their decommissioning plan to the NRC, including a Post-Shutdown Decommissioning Activities Report ("PSDAR"), an Irradiated Fuel

Management Plan ("IFMP"), and a Site Specific Decommissioning Cost Estimate ("DCE"). *See* Add. 26-146.

Licensees' PSDAR provided a general overview of the timetable for the decommissioning, decontamination, restoration, and license termination activities at the SONGS site. The PSDAR specified that Licensees would begin transferring spent nuclear fuel from wet pools to dry storage in the SONGS Independent Fuel Storage Installation ("ISFSI") in 2014, and complete the transfer by June 2019. *See* Add. 37. Thereafter, Licensees proposed to store the spent nuclear fuel in the ISFSI during decommissioning from June 2019 to December 2031. *Id.* Finally, Licensees proposed to store the spent nuclear fuel in the ISFSI during a post-decommissioning period from December 2031 to December 2049. *Id.* This timeline was based on the assumptions that the DOE will begin accepting spent nuclear fuel from the industry in 2024, that all spent nuclear fuel will be permanently removed from the ISFSI and transferred to an off-site permanent repository by 2049, and that the SONGS site will be restored to a condition acceptable for unrestricted use and returned to the U.S. Navy by 2051. *Id.* Licensees expressly based this assumption on some unspecified "previously documented positions of

the DOE, which indicates that shipments from the industry could begin as early as 2024 and SONGS place in the current queue." *Id.* Notably, however, Licensees acknowledged that both the date on which the DOE would begin accepting spent nuclear fuel from the industry and SONGS' place in the queue "are subject to change." *Id.*

Licensees' IFMP provides additional details regarding their strategy for storing, monitoring, and managing spent nuclear fuel at the SONGS ISFSI during and after the decommissioning period. *See* Add. 63-77. Like the PSDAR, Licensees' IFMP is expressly based on the assumptions that the DOE would begin accepting spent nuclear fuel from the industry in 2024 and that all spent nuclear fuel would be permanently removed from the SONGS ISFSI by 2049. Add. 68. Again, however, Licensees provided no objective evidentiary support for these critical assumptions.

Finally, Licensees' DCE provided a detailed estimate of the anticipated costs of the decommissioning and spent fuel management activities at SONGS. *See* Add. 79-171. Licensees projected that the total cost of decommissioning and restoring the SONGS site would exceed $4 billion, of which approximately $1.3 billion was allocated for spent fuel

management at the SONGS site through 2049. Add. 87. Once again, Licensees' based their DCE on the assumptions that the DOE will begin accepting spent nuclear fuel from the industry in 2024 and that all spent nuclear fuel will be removed from SONGS by 2049. Add. 92. Significantly, Licensees' DCE expressly acknowledged that "DOE has not committed to accept [their] canistered spent fuel." Add. 106. Despite this acknowledgment, the DCE also confusingly stated: "But for purposes of this estimate, it is assumed that an [Edison-funded] dry storage facility will not be necessary." *Id.*

At the time Licensees submitted their PSDAR, IFMP, and DCE, there was, in fact, no viable plan or intention for the DOE to begin accepting spent nuclear fuel in 2024, or any other time. Indeed, Licensees submitted their PSDAR, IFMP, and DCE approximately 4 years after the DOE withdrew its application for a license to construct a permanent repository for spent nuclear fuel at Yucca Mountain in Nevada, and approximately 3 years after the NRC suspended its adjudicatory proceeding regarding the withdrawal of the DOE's license application. *See* Add. 173-187. In other words, the NRC is permitting Licensees' to bury hundreds of tons of one of the most toxic substances

known to human kind pursuant to a decommissioning plan that was, and remains today, completely untethered to objective reality.

III. Licensees' selection of a defective storage system and thin-wall canisters

At the time Licensees submitted their decommissioning plan to the NRC, they had not yet identification a location for expanding the SONGS ISFSI, nor had they selected storage equipment or vendors for the build out of the ISFSI. *See* Add. 64. In December 2014, Licensees selected a location for the expanded SONGS ISFSI and selected Holtec International's ("Holtec") HI-STORM UMAX storage system for the "temporary" storage of spent nuclear fuel. *See* Add. 188-191. The location selected for the ISFSI is a mere 108 feet from the Pacific Ocean, within a tsunami zone surrounded by active fault lines, and little more than a foot above the mean high tide level, making it especially susceptible to flooding as sea levels rise. *See* Add. 193-94. Although Licensees' decommissioning plan claimed that spent nuclear fuel would

be stored at the SONGS ISFSI for approximately 30 years,[2] Holtec only warranted its storage system for 10 years. *See* Add. 206.

Regardless of how many decades nuclear waste is interred in the beach at San Onofre, there is substantial evidence demonstrating that the actual canisters used to store this radioactive fuel—canisters also designed and manufactured by Holtec—were defectively manufactured and designed. The fitness of these defective canisters has been further compromised by their negligent handling, transportation, and burial, resulting in contact deformities and broken parts in many (if not all) of the canisters already buried in the ISFSI. Given that each of the defective canisters contain more deadly radioactive Cesium-137 than was released

[2] This estimate has been shown to be wildly unrealistic. For example, the United States Nuclear Waste Technical Review Board has concluded that spent nuclear fuel repackaged into smaller canisters would be too hot to move until approximately 2070, and that larger canisters "would not be cool enough to meet the transportation requirements until approximately 2100." *See* U.S. Nuclear Waste Technical Review Board, *Preparing for Nuclear Waste Transportation: Technical Issues that Need to Be Addressed in Preparing for a Nationwide Effort to Transport Spent Nuclear Fuel and High-Level Radioactive Waste* (Sept. 2019), at 77 (available at https://www.nwtrb.gov/docs/default-source/reports/nwtrb_nuclearwastetransport_508.pdf?sfvrsn=6).

during the entire Chernobyl disaster, the failure of even one will have calamitous consequences for the residents of Southern California.

Some of these dangerous conditions flow directly from Holtec's failure to meet minimum safety thresholds for the design and manufacture of nuclear waste storage containers. The Holtec canisters are so-called thin-walled canisters, with only a 5/8-inch thick stainless-steel wall surrounding an aluminum egg-crate structure that Holtec says can hold up to 37 spent fuel assemblies. Holtec is obligated to design, manufacture, and supply the canisters under strict guidelines promulgated by the NRC and applicable certificates of compliance ("CoCs"). *See* Add. 210-214. But each CoC is conditioned on the holder strictly hewing to specific technical specifications and approved design features. Here, after CoCs for the thin-wall canisters were issued, Holtec surreptitiously modified the design of the canisters, apparently to reduce manufacturing costs or correct a perceived flaw in the original design. By concealing this change from the NRC, Holtec avoided a costly and time-consuming design review and risk analysis. And as outlined in detail below, this design change introduced a critical flaw into casks that are now holding tons of radioactive nuclear waste.

Apart from the canisters' inherently defective design, Holtec also designed and built a flawed system for inserting loaded canisters into ISFSI. Because Holtec designed the downloading system with narrow tolerances of less than one inch, every canister has been damaged during the process. Over time, these contact deformities can grow into cracks, rendering the canisters susceptible to leaking and preventing their safe removal. What's more, Licensees have no way to visually inspect all of the surfaces of the canisters once they are in the ground, and no way to fix damage that is detected. In other words, even if Licensees perform burial operations exactly according to plan, they will bury dangerous nuclear waste in damaged canisters that cannot be thoroughly inspected or safely retrieved.

Unfortunately, this danger is not hypothetical. As outlined more fully below, the NRC has already acknowledged that in addition to the contact deformities referred to above, the base of at least one buried canister has already been damaged as a result of what Licensees euphemistically label a "near miss" incident. Despite the burial of a damaged canister full of highly radioactive nuclear waste next to the beach, the NRC has recently allowed burial activities to resume without

an independent, objective assessment of the risks inherent with using the Holtec system.

Finally, spent fuel from Generating Units 2 & 3 has been safely stored in wet storage at SONGS for years. Neither the NRC nor Licensees has ever suggested that the wet storage created a risk to the public or environmental. However in connection with moving spent fuel from wet to dry storage, Licensees have now obtained permission to demolish the wet storage facilities at SONGS as soon as all the fuel is transferred. The net result will be that once demolished, there will be no wet storage facility at SONGS should a canister fail and fuel has to be removed from its silo. Without a wet storage facility at SONGS, and no facility in the United States to remove dry storage spent fuel, the danger will have to be addressed—if at all—above ground at SONGS.

IV. NRC repeatedly granted unsupported license amendments and exemptions for SONGS

NRC originally granted a limited license for SONGS—one that only permitted Licensees to operate the power generation plant and temporarily store spent nuclear fuel and waste in wet pools. When even Licensees could not purport to be safely operating the plant, they had to secure a license amendment from the NRC to begin decommissioning

operations. Rather than seeking to remove the nuclear waste they had created at the site, Licensees decided to use SONGS for an entirely different purpose—that is, the long-term storage of spent nuclear fuel. Thus, the grant or denial of the Licensees' request for a license amendment was a matter of significant public concern, requiring an opportunity for meaningful public participation.

Yet, without meaningful public participation or an independent assessment, on July 17, 2015, the NRC granted Licensees' request for a license amendment that permitted them to begin decommissioning the SONGS facility. *See* Add. 215-358. Specifically, the NRC authorized Licensees to "Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition." Add. 221. In so doing, the NRC "found" that there was "reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations." Add. 218. Both assurances have proven to be unfounded.

Despite the suggestion that the NRC made an independent finding on these points, in fact, the agency did not use objectively verifiable criteria or an independent analysis concerning the dangers and risks associated with Licensees' plan. Rather, the NRC allowed Licensees to present their internal, untested, and unchecked conclusions as if they were scientific fact. The analysis underlying these conclusions remain concealed from the public under the guise of containing proprietary information. Needless to say, such a review did not comply with the NRC's statutory mandate to independently protect the health and safety of the public and the environment. Nor did it provide the public with the material information necessary to assess the validity of Licensees' proposal.

V. Holtec's surreptitious redesign of dry storage canisters

Licensees have claimed that the thin-walled canisters manufactured by Holtec are "state of the art" receptacles, specifically designed to hold extremely hot radioactive material in an air-cooled chamber. Among the design features touted by Holtec were "stand-off shims" in the canisters, which purportedly enhanced convection cooling of the hot fuel assemblies by creating additional space to allow helium

gas to flow throughout the canister. Holtec claimed that its revolutionary design prevented overheating of radioactive fuel, and would be as safe (or safer) than the wet storage pools already used throughout the country. In actual fact, many of the canisters already buried at the site were altered from the original design, a fact that Holtec concealed from the NRC and the public until new and troubling defects were inadvertently discovered. Despite this deception and incompetence by Holtec, Licensees continue to use Holtec canisters to bury spent nuclear fuel at SONGS.

In February 2018, while preparing to load one of the Holtec canisters with spent nuclear fuel, Licensees discovered a loose bolt inside. When confronted with this embarrassing fact, Holtec grudgingly revealed that it had redesigned its canisters to include a different "stand-off shim" that included bolts—a part not included in the original design. As Licensees and Holtec discovered, however, these bolts were susceptible to breaking loose inside the canister. With tons of nuclear fuel no longer being supported by shims, airflow within the canister was necessarily restricted, potentially causing a failure of the canister's "improved"

cooling mechanism. Obviously, if left uncooled, spent nuclear fuel can heat to the point of a critical—and deadly—nuclear reaction.

Such a dangerous failure should never have been possible. Under NRC regulations, any design change that would result in more than a minimal increase in the frequency or likelihood of an accident, malfunction, or the consequences of such accident or malfunction, must be brought to the attention of the NRC. Given the importance of the cooling mechanism to canister safety, Holtec was required to obtain a CoC amendment *prior to* implementing any proposed design change. Despite the serious risks posed by its design changes, Holtec decided not to even notify the NRC, much less obtain a CoC amendment.

Unfortunately for the public, because Holtec's defective design change was made surreptitiously, defective canisters *have already been used* to bury tons of nuclear fuel. On March 22, 2018, Licensees' admitted during a Community Engagement Panel Meeting that four canisters with the defective shim design had been filled with spent nuclear fuel and buried at SONGS. Licensees also acknowledged during this meeting that no method exists for safely opening the defectively designed canisters to inspect the stand-off shims. Add. 589-90. Thus, because Licensees have

hewn to artificial deadlines for burying radioactive fuel, there is now no way to inspect the fuel assemblies and cooling mechanisms to determine if they have been compromised.

The NRC subsequently found that Holtec had failed to establish adequate design control over components important to safety, and failed to perform evaluations before making important design changes. But the NRC–in a further abdication of its mission to protect the public and the environment—declined to impose a fine or any other penalty on Holtec for these violations.[3]

[3] In March 2019, an NRC inspector issued an internal report concluding that the damaged and defective Holtec canisters would require a formal design change, approved by the NRC, if they were to continue in service under the applicable CoCs. *See* Add. 903-906 and Add. 923-930. On May 21, 2019, however, the NRC disregarded the findings of its own inspector, and authorized a resumption of the moving and burial of spent nuclear fuel at SONGS. *See* Add. 766-67.

In short, despite Holtec's history of misconduct and deceit,[4] the NRC has continued to accept the company's representations regarding its defective and dangerous canisters, and has approved multiple amendments to its CoCs and thereby permitted Holtec to continue the use of its canisters at SONGS (and elsewhere).

VI. Licensees' multiple decommissioning disasters

From the outset, Licensees' decommissioning operations with Holtec have been marred by a series of miscues, poor managerial oversight, and attempts to conceal the same from the NRC and the public. Unsurprisingly, this behavior has caused Licensees to repeatedly fall short of the NRC's standards and regulations.

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[4] In October 2010, Holtec was debarred by the Tennessee Valley Authority ("TVA") in connection with improper and undisclosed payments the company made to a federal official in order to secure a contract at the Brown Ferry Nuclear Plant. *See* Add. 774-822. Following that debarment, Holtec sought a $260 million tax break related to a nuclear plant project in Camden, New Jersey. As part of that process, Holtec's CEO submitted certified forms where he answered "no" to the question of whether Holtec had ever been barred from doing business with a state or federal agency. In June 2019, New Jersey regulators froze Holtec's $260 million tax-incentive award pending further investigation. *See* Add. 823-902. Thus, Holtec's representations should be treated with caution and subject to independent verification.

A. Licensees compromised the structural integrity of multiple canisters

As revealed in NRC documents and at public hearings, the Licensees have already gouged and buried at least **29** fully loaded canisters at SONGS. Add. 531. Experts believe this gouging may lead to deeper, through-the-wall cracks, which will make the future safe movement of these canisters impossible. Experts also point out that damage to the canisters will be exacerbated by the presence of salt air, fog, rain, and salt water—the precise conditions to which the canisters are exposed in their current location, just steps from the Pacific Ocean. *See* Add. 191-202.

Additionally, many (if not all) of the Holtec canisters have been negligently scratched during transportation to the ISFSI. For example, according to an NRC inspection report, and as admitted at a Community Engagement Panel Meeting by an NRC spokesperson, every single canister was damaged during the downloading process: "The canister involved in the near-drop event [and] all the other canisters . . . experienced a little bit of scuffing, and a little bit of contact going into the ISFSI." *See* Add. 531. And at least one NRC inspector has concluded that damage inflicted on the canisters during loading rendered them out

of compliance with the applicable CoC. *See* Add. 903-906 and Add. 923-930. Despite this conclusion from its own inspector, the NRC has cleared the way for Licensees to bury more defective canisters at SONGS.

B. Licensees nearly dropped two 49-ton canisters full of deadly radioactive nuclear waste, and then attempted to cover it up

On July 22, 2018, Licensees were attempting to insert a 49-ton canister full of radioactive nuclear fuel into the ISFSI. Add. 474. Because of their negligent design and oversight, they did not notice when the canister became stuck on a ¼-inch thick steel guide ring near the top of the chamber. Although the canister had halted its descent, Licensees continued to unwind the safety cables that were designed to hold the canister secure during movement and burial. *Id.* In so doing, Licensees left the canister caught on a thin piece of metal, unprotected from a possible fall of more than 18 feet to the concrete floor below. The NRC later referred to this incident as an "unsecured load event." More accurately, this debacle risked turning San Onofre State Beach into a uninhabitable nuclear wasteland.

Despite the fact that any incident involving nuclear waste must be reported to the NRC within 24 hours, *see* 10 C.F.R. § 72.75, this incident

was not formally reported on the NRC's Event Notifications Report. Indeed, Licensees have *never* provided a formal report for this event on July 22. As a result, the public was kept in the dark—and remains largely uninformed—about this potentially disastrous incident.

Ten days later, on August 3, 2018, the Licensees once again lost control of a 49-ton canister full of radioactive nuclear waste while lowering it into a storage silo. Add. 459-465. Just as with the July 22 incident, Licensees' employees snagged the canister on a ¼-inch wide steel ring, and did not realize that the safety equipment was no longer holding the canister. *Id.* Instead, the canister was precariously perched on a narrow metal flange, hovering almost 20 feet above the concrete floor of the ISFSI for almost an hour. *Id.*; *see also* Add. 568-571. Again, Licensees did not disclose this extremely dangerous event to the public, and did not provide proper notification to the NRC.

Six days after the second "unreported" incident, during a Community Engagement Panel meeting, Edison's Vice President and Chief Nuclear Officer notified the public that work at the ISFSI had stopped, but falsely claimed that the stoppage was planned in order to perform necessary maintenance, provide employees with time off, and

analyze the overall efficiency and effectiveness of the decommissioning process at that point. During a public comment portion of the event, a whistleblower employed as a contractor at the facility bravely disclosed that Licensees had almost dropped a canister of nuclear waste the week before. This disclosure not only shed light on the Licensees' dangerous practices at the ISFSI, but also directly contradicted their public statement that the work stoppage was a "planned event."

Apart from the loss of public confidence in Licensees' activities, these near disasters also injected additional dangers into the burial process. The entire weight of each canister—all 49 tons—was pressed onto a small portion of the base that had been stuck on the metal flange. Under this extreme weight, "molding" or disfigurement occurred at the base of the canister. Rather than inspecting or repairing the base, however, Licensees eventually lowered the damaged canister into the silo. As no method exists to inspect the damaged base of the canister, the scope and significance of the damage to the loaded canister—as well as the integrity of the base—remains a complete mystery. Indeed, while Licensees and Holtec insist they can remove a canister from its silo to

conduct an inspection, they have made no attempt to remove either canister to check for damage.

In response to the July 22 and August 3 "near-miss" events, the NRC imposed of a wrist-slapping fee of $116,000. *See* Add. 567-572 and Add. 573-585. Although the NRC did not order the Licensees to cease operations, the Licensees "voluntarily agreed" to discontinue the movement of spent nuclear fuel out of wet storage at SONGS. For the next 11 months, Licensees and Holtec halted all fuel transfers at SONGS. At no time during this extended work stoppage did the NRC, Licensees, or Holtec suggest that the continued wet storage of spent fuel at SONGS posed a danger to the community.

VII. The NRC recently permitted licensees to resume moving and burying spent nuclear fuel

In July 2019, following an 11-month hiatus on moving spent fuel from the relative safety of wet storage, Licensees assured the NRC that its operations were safe to resume the transfer of radioactive waste into Holtec canisters. With the NRC's blessing, Licensees resumed their decommissioning operations, including the burial of spent nuclear fuel into the ISFSI. Add. 767. Within a few days, Licensees stopped operations on at least two occasions because of safety incidents—events

caused by safety deficiencies that Licensees had assured the NRC and public were resolved.

Given the dangers associated with the renewed canister burial, as well as pendency of litigation in federal district court seeking to halt this process,[5] Petitioner requested that Licensees briefly halt the burial of additional nuclear waste and resume their previously self-imposed suspension of spent fuel transfer. *See* Add. 768-770. Licensees declined the request, vowing to "continue the transfer operations" and bury spent nuclear fuel at SONGS as quickly as possible. *See* Add. 771-773; *see also* Add. 559-566. To date more than 33 canisters have been buried at SONGS, with a new canister being loaded and buried every eight days.

VIII. NRC has failed to even acknowledge Petitioner's request for administrative relief

On September 24, 2019, Petitioner filed a 2.206 Petition with the NRC, requesting the immediate suspension to the movement and burial

[5] *Public Watchdogs v. Southern California Edison, et al.*, Case No. 19-CV-1635-JLS (MSB) (S.D. Cal.). Petitioner's Amended Motion for Temporary Restraining Order and Preliminary Injunction are fully-briefed and pending before the district court. Concurrently, however, Defendants have moved to dismiss the Amended Complaint by arguing, *inter alia*, that the dispute belongs before the NRC or this Court.

of spent nuclear fuel at SONGS.[6] Petitioner supported its 2.206 Petition with 38 exhibits, spanning more than 1,500 pages.[7] Because Licensees had refused Petitioner's request to suspend burying operations—something Licensees had voluntarily agreed to do just a few months earlier—Petitioner requested expedited review and adjudication.

Pursuant to its own regulations, the NRC is obligated "[w]ithin a reasonable time after a request . . . has been received . . . [to] either institute the requested proceeding . . . [or] advise the person who made the request in writing that no proceeding will be instituted in whole or in part, with respect to the request, and the reasons for the decision." 10 C.F.R. § 2.206(b). The NRC has not acted upon the 2.206 Petition, or even acknowledged it. The NRC has not communicated with Petitioner

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[6] "Any person may file a request to institute a proceeding pursuant to § 2.202 to modify, suspend, or revoke a license, or for any other action as may be proper." 10 C.F.R. § 2.206(a).

[7] To be sure, Petitioners were only required to "specify the action requested and set forth the facts that constitute the basis for the request." 10 C.F.R. § 2.206(a). Nonetheless, because Licensees had refused to continue their voluntary cessation in burial operations, thereby creating artificial time pressures for SONGS and the community, Petitioners decided to thoroughly support their request for extraordinary relief.

regarding the status of the 2.206 Petition, and no rules exist at the agency to set timetables or deadlines for reviewing and deciding petitions. Such a dilatory response by the NRC is unsurprising; to the best of Petitioner's knowledge, the NRC has *never* granted a 2.206 Petition.

This documented inaction by the NRC demonstrates the futility of simply waiting for the administrative process to play out. Even if the NRC took the unprecedented step of acting upon the 2.206 Petition, Licensees have made clear they will use every available moment to move and bury *all* spent nuclear fuel at SONGS. At the rate of one fully loaded canister every eight days, in a matter of weeks all the spent fuel at SONGS will be transferred. Moreover, destruction of the wet storage chambers will commence. Thus, the relief Public Watchdogs seeks—a temporary halt to the movement of nuclear fuel, and performance of an independent risk assessment—cannot be secured in a proceeding before the NRC absent extraordinary relief from this Court.

MANDAMUS RELIEF IS WARRANTED

Because no one expects the NRC to issue a decision on Public Watchdog's 2.206 Petition until *after* all the radioactive fuel at SONGS is moved and buried, this Court should act to protect its jurisdiction over

this dispute by issuing a writ of mandamus. *See In re California Power Exch. Corp.*, 245 F.3d 1110, 1119 (9th Cir. 2001) (mandamus relief authorized when "necessary to protect [the Ninth Circuit's] 'prospective jurisdiction.'"). Given the gravity of the threat facing the residents of Southern California, such extraordinary relief is appropriate.

In considering a mandamus petition against a federal agency, the Ninth Circuit has adopted the "TRAC factors" test, first articulated in *Telecomm. Research & Action Ctr. v. Fed. Communications Comm'n*, 750 F.2d 70 (D.C. Cir. 1984) ("*TRAC*").

> These factors are: (1) the time agencies take to make decisions must be governed by a rule of reason; (2) where Congress has provided a timetable or other indication of the speed with which it expects the agency to proceed in the enabling statute, that statutory scheme may supply content for this rule of reason; (3) delays that might be reasonable in the sphere of economic regulation are less tolerable when human health and welfare are at stake; (4) the court should consider the effect of expediting delayed action on agency activities of a higher or competing priority; (5) the court should also take into account the nature and extent of the interests prejudiced by delay; and (6) the court need not find any impropriety lurking behind agency lassitude in order to hold that agency action is unreasonably delayed.

In re Pesticide Action Network, 798 F.3d at 813 (9th Cir. 2015) (quoting *TRAC*, 750 F.2d at 79-80). Although all these factors must be examined, the most important component of the test is whether the agency's

timetable for taking action comports with the "rule of reason." *In re A Community Voice*, 878 F.3d at 786.

The first two factors clearly weigh in favor of mandamus relief. Just three months ago, Licensees resumed burying nuclear fuel in a place and in a manner that exposes the public and environment to the risk of a deadly radiation release. Throughout the decommissioning process, the NRC has effectively turned a blind eye to repeated safety hazards created by Licensees including, among others, the use of damaged and defective canisters, inadequate safety procedures, incompetent supervision, and the absence of a reliable means to inspect and monitor spent fuel after it has been moved from the relative safety of wet storage. Moreover, the NRC has permitted Licensees' to implement their decommissioning plan despite the indisputable fact that it is predicated upon the fanciful assumption that spent nuclear fuel will remain buried at SONGS only temporarily. By extending such extraordinary deference to Licensees' handling of radioactive waste—in the face of stunning admissions of incompetence and deception—the NRC has demonstrated that it will not act on its own to protect the residents of Southern California.

Petitioners were therefore forced to seek agency action through a 2.206 Petition. "The APA requires agencies to conclude a matter presented to it within a reasonable time. This has been interpreted to mean that an agency has a duty to fully respond to matters that are presented to it under its internal processes." *In re A Community Voice*, 878 F.3d at 784 (citing and quoting 5 U.S.C. § 555(b)). Under its own rules, the NRC was required to respond within "a reasonable time after" the 2.206 Petition was filed. But with its failure to even *acknowledge* the 2.206 Petition—which explicitly requested expedited consideration to address the imminent risk of permanent harm to the public and environment—the NRC has acknowledged there will be no timetable for agency action, and Licensees will have enough time to bury all the spent fuel at SONGS. A delay in agency action that effectively precludes any possibility of relief cannot be said to conform to the "rule of reason." *See In re A Community Voice*, 878 F.3d at 785-86 (rejecting EPA's argument that it only had a duty "begin a proceeding"; rather, agency was required to "fully respond" to petition in a meaningful way); *Pub. Citizen Health Research Grp. v. Auchter*, 702 F.2d 1150, 1154 (D.C. Cir. 1983) (failure to respond to petition while workers were in "grave danger" was grounds

for relief); *Envtl. Def. Fund, Inc. v. Hardin*, 428 F.2d 1093, 1099 (D.C. Cir. 1970) (judicial action justified when "administrative inaction is the equivalent of an order denying relief").

This conclusion is reinforced when one considers the third and fifth factors of the *TRAC* test—that is, "delays that might be reasonable in the sphere of economic regulation are less tolerable when human health and welfare are at stake," and "the nature and extent of the interests prejudiced by delay." *TRAC*, 750 F.2d at 80. To be sure, most of the cases in which agency inaction has been found to violate the "rule of reason" have involved delays significantly longer than here. *See, e.g., In re A Community Voice*, 878 F.3d at 787 (EPA's delay of eight years, along with its request for another six years to act upon a request, deemed unreasonable); *In Re Pesticide Action Network*, 798 F.3d at 814 (EPA's delay of eight years with no "concrete timetable for resolving the petition" deemed unreasonable). And typically, the "cases in which courts have afforded relief have involved delays of years, not months." *In re California Power Exch. Corp.*, 245 F.3d at 1125 (collecting cases involving FCC, ICC, FERC). But while other federal agencies consider important decisions that impact the health and safety of the public and the

environment, Petitioner is unaware of any case involving a threat as imminent and dire as the one posed from improperly transporting and burying tons of radioactive spent nuclear fuel in defective and damaged canisters, feet from the Pacific Ocean, between active fault lines, in a tsunami zone, and pursuant to a decommissioning plan that falsely assumes this storage is temporary. "When the public health may be at stake, the agency must move expeditiously to consider and resolve the issues before it." *Pub. Citizen Health Research Grp. v. Comm'r, Food & Drug Admin.*, 740 F.2d 21, 34 (D.C. Cir. 1984). And since the NRC has given no indication when it will even begin reading the 2.206 Petition, there is no "concrete timetable" for its decision. *Cf. Cent. Sierra Envtl. Res. Ctr. v. Stanislaus Nat'l Forest*, 304 F. Supp. 3d 916, 952 (E.D. Cal. 2018) (rejecting claim of unreasonable delay in part because Forest Service "has a concrete timeline for completion by 2019").

Given the existential threat posed to the residents of Southern California by the Licensees' action, and the amount of time it will take for the NRC to consider the 2.206 Petition—by which time all the radioactive waste will have been buried, and possibly even leaked out of the ISFSI—the delay here cannot be said to satisfy the "rule of reason."

CONCLUSION

Based on the false assumption that spent nuclear fuel will be stored at SONGS only temporarily, Licensees are moving hundreds of tons of radioactive material from the relative safety of wet storage pools, inserting it into thin-walled canisters, damaging the canisters during loading, and burying them where they cannot be fully monitored, inspected, repaired, or safely removed. Licensees have a proven track record of negligence (if not recklessness) with loading canisters into the ISFSI, having *twice* nearly dropped a 49-ton canister full of spent nuclear fuel almost 20 feet. These burials are taking place in perhaps the most hazardous location possible—merely 108 feet from a rising Pacific Ocean, in a tsunami zone surrounded by active fault lines, in a humid and salty environment that corrodes metal. Rather than confronting these deficiencies in a forthright matter, Licensees have engaged in a sustained campaign of obfuscation and secrecy.

In sum, Licensees have swerved onto a dangerous course without adequately considering the grave risks, or reasonable alternatives. Because their movement and storage of dangerous nuclear waste could irreparably harm Southern California for decades, their current course

of action must be stopped cold, lest they turn SONGS into a proverbial "ticking time bomb." Extraordinary mandamus relief is necessary to avoid this quickly materializing disaster.

Dated: October 21, 2019

Respectfully submitted,
BARNES & THORNBURG LLP

By: /s/ Charles G. La Bella
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Eric J. Beste
Attorneys for Plaintiff
PUBLIC WATCHDOGS

STATEMENT OF RELATED CASES

Pursuant to Circuit Rule 28-2.6, Petitioner states that there are no related cases pending before this Court.

/s/ Charles G. La Bella
Charles La Bella

CERTIFICATE OF COMPLIANCE

Pursuant to Circuit Rule 32(7), counsel for Petitioner certifies that this brief complies with this Court's type-volume limitations and contains 7,265 words.

/s/ Charles G. La Bella
Charles La Bella

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

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Signature: /s/ Stacey L. Evans

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UNITED STATES NUCLEAR REGULATORY COMMISSION

Before the Executive Director for Operations

PUBLIC WATCHDOGS, a California 501(c)(3) corporation, Petitioner, v. SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY, Licensees.	**10 C.F.R. § 2.206 PETITION TO IMMEDIATELY SUSPEND DECOMMISSIONING OPERATIONS AT SAN ONOFRE NUCLEAR GENERATING STATION UNITS 2 AND 3**

Pursuant to 10 C.F.R. § 2.206, Petitioner Public Watchdogs ("Petitioner") hereby submits its Petition to Immediately Suspend Decommissioning Operations at San Onofre Nuclear Generating Station ("SONGS") Units 2 and 3:

PRELIMINARY STATEMENT

1. As part of the ongoing decommissioning of SONGS Units 2 and 3, Licensees Southern California Edison Company ("Edison") and San Diego Gas & Electric Company (collectively, "Licensees") are in the process of burying hundreds of tons of deadly spent nuclear fuel a mere 108 feet from one of California's most populated public beaches, within a tsunami zone surrounded by active fault lines, in canisters that are damaged, defective, and not properly designed to serve their intended purpose. Throughout the decommissioning process, the Nuclear Regulatory Commission ("NRC") has effectively turned a blind eye to multiple alarming safety hazards created by Licensees' burial of spent nuclear fuel at SONGS, including evidence that the canisters being used by Licensees are damaged and defective, and that Licensees do not have adequate safety procedures or competent staff to complete the transfer of the spent nuclear fuel from wet to dry storage.

2. What's more, the NRC's various actions permitting the implementation of Licensees' decommissioning plan and authorizing Licensees' dangerous burial of spent nuclear fuel at SONGS are based on unreasonable and fundamentally flawed assumptions that: (1) the United States Department of Energy ("DOE") will begin accepting spent nuclear fuel from nuclear generating stations like SONGS in 2024 or 2028; (2) all of the spent nuclear fuel currently being buried at SONGS will be permanently removed from the site by 2049; and (3) the SONGS site will be restored to a condition that is acceptable for unrestricted use by 2051. In fact, no central repository for permanent storage of spent nuclear fuel exists in the United States, there is no viable plan to open such a permanent repository, and the DOE undoubtedly will not begin accepting spent nuclear fuel for permanent storage from SONGS or any other nuclear generating station in 2024, 2028, or any other time in the foreseeable future. As the United States Court of Appeals for the District of Columbia Circuit has observed: "At this time, there is not even a prospective

site for a repository, let alone progress toward the actual construction of one." *New York v. Nuclear Regulatory Com'n*, 681 F.3d 471, 474 (D.C. Cir. 2012).

3. By ignoring the manifold safety hazards posed by Licensees' decommissioning operations and permitting Licensees to implement their decommissioning plan based on the unreasonable assumption that spent nuclear fuel will be stored at SONGS only temporarily, the NRC has abdicated its paramount responsibility to protect public health and safety and it has failed to ensure Licensees will have adequate funds to pay for the full cost of decommissioning and restoring the SONGS site through the termination of their license. Accordingly, Petitioners respectfully request that the NRC issue an order immediately suspending all decommissioning operations at SONGS, including the burial of spent nuclear fuel at the SONGS site, and requiring Licensees to submit an amended decommissioning plan that properly accounts for the reality that the spent nuclear fuel being buried at SONGS will remain there indefinitely.

FACTUAL BACKGROUND

I. LICENSEES' NEGLIGENT OPERATION OF SONGS

4. In August 1963, Congress enacted Public Law 88-82 authorizing the "construct[ion], operate[ion], maintain[enance], and use" of a nuclear power plant on approximately 90 acres of land located at the Camp Pendleton military base. In May 1964, the United States of America granted Licensees an easement for the sole purpose of "construction, operation, maintenance and use of a nuclear electric generating station" at the Camp Pendleton site.

5. Licensees operated three nuclear electric generating units at SONGS. Licensees operated Unit 1 from approximately 1968 until 1992, when they began the decommissioning process for that unit. Licensees operated Units 2 and 3 from approximately 1983 and 1984 (respectively) until June 12, 2013, when they submitted written certification to the NRC that they were permanently ceasing operation of those units.

6. Throughout its time as an operational nuclear power plant, SONGS was marred by numerous instances of poor safety and regulatory compliance, which ultimately contributed to the cessation of operations at the site. These compliance debacles included the backward installation of a 420-ton nuclear reactor vessel and the installation of replacement steam generators, without obtaining the requisite approval from the NRC, which ultimately malfunctioned and leaked deadly radioactive steam at the site.

II. LICENSEES' FUNDAMENTALLY FLAWED DECOMMISSIONING PLAN

7. On September 23, 2014, Licensees submitted their decommissioning plan to the NRC, including a Post-Shutdown Decommissioning Activities Report ("PSDAR"), an Irradiated Fuel Management Plan ("IFMP"), and a Site Specific Decommissioning Cost Estimate ("DCE"). *See* **Exhibits 1, 2, and 3.**

8. Licensees' PSDAR provided a general overview and timetable for the decommissioning, decontamination, restoration, and license termination activities at the SONGS site. The PSDAR specified that Licensees would begin transferring spent nuclear fuel to dry storage in the SONGS Independent Spent Fuel Storage Installation ("ISFSI") in 2014, and complete the transfer by June 2019. *See* **Exhibit 1**. Thereafter, Licensees proposed to store the spent nuclear fuel in the ISFSI during decommissioning from June 2019 to December 2031. *Id*. Finally, Licensees proposed to store spent nuclear fuel in the ISFSI during a post-decommissioning period from December 2031 to December 2049. *Id.* This timeline was based on the assumption that the DOE will begin accepting spent nuclear fuel from the industry in 2024, that all spent nuclear fuel will be permanently removed from the SONGS ISFSI and transferred to an off-site permanent repository by 2049, and that the SONGS site will be restored to a condition acceptable for unrestricted use and returned to the U.S. Navy by 2051. *Id*. Licensees expressly based this assumption on some unspecified "previously documented positions of the DOE, which indicates that shipments from the industry could begin as early as 2024 and SONGS place in the current queue." *Id*. Notably, however, Licensees acknowledged that both the date on which the

DOE would begin accepting spent nuclear fuel from the industry and SONGS place in the queue "are subject to change." *Id*.

9. Licensees' IFMP provides additional details regarding their strategy for storing, monitoring, and managing spent nuclear fuel at the SONGS ISFSI during and after the decommissioning period and through ultimate termination of the SONGS licenses. *See* **Exhibit 2**. Like the PSDAR, Licensees' IFMP is expressly based on the assumptions that the DOE would begin accepting spent nuclear fuel from the industry in 2024 and that all spent nuclear fuel would be permanently removed from the SONGS ISFSI by 2049. *Id.* Again, however, Licensees provided no objective evidentiary support for these critical assumptions.

10. Finally, Licensees' DCE provided a detailed estimate of the anticipated costs of the decommissioning and spent fuel management activities at SONGS. *See* **Exhibit 3**. Licensees projected that the total cost of decommissioning and restoring the SONGS site would exceed $4 billion, of which approximately $1.3 billion was allocated for spent fuel management through 2049. *Id*. Once again, Licensees based their DCE on the assumptions that the DOE will begin accepting spent nuclear fuel from the industry in 2024 and that all spent nuclear fuel will be removed from the SONGS ISFSI by 2049. *Id*. Significantly, however, Licensees' DCE expressly acknowledged that "DOE has not committed to accept [Edison's] canistered spent fuel." *Id*. Despite this acknowledgment, the DCE also confusingly stated: "But for purposes of this estimate, it is assumed that an [Edison-funded] dry storage facility will not be necessary." *Id.*

11. At the time Licensees submitted their PSDAR, IFMP, and DCE, there was, in fact, no viable plan or intention for the DOE to begin accepting spent nuclear fuel in 2024 or any other time. Indeed, Licensees submitted their PSDAR, IFMP, and DCE approximately 4 years after the DOE withdrew its application for a license to construct a permanent repository for spent nuclear fuel at Yucca Mountain in Nevada and approximately 3 years after the NRC suspended its adjudicatory proceeding regarding the withdrawal of the DOE's license application. *See* **Exhibit 4**. In other words, the

fundamental predicate for Licensees' decommissioning plan was, and remains today, a pure fiction that is completely untethered to objective reality.

III. LICENSEES' SELECTION OF HOLTEC'S HI-STORM UMAX STORAGE SYSTEM AND DEFECTIVE THIN-WALL CANISTERS

12. At the time Licensees submitted their decommissioning plan, they had not yet identified a location for the expanded SONGS ISFSI, nor had they selected storage equipment or vendors for the build out of the ISFSI. *See* **Exhibit 2**.

13. In December 2014, Licensees selected a location for the expanded SONGS ISFSI and selected Holtec International's ("Holtec") HI-STORM UMAX storage system for the "temporary" storage of spent nuclear fuel. *See* **Exhibit 5**. The location selected for the ISFSI is a mere 108 feet from the Pacific Ocean, within a tsunami zone surrounded by active fault lines, and little more than a foot above the mean high tide level, making it especially susceptible to flooding as sea levels rise. *See* **Exhibit 6**. Notably, although Licensees' decommissioning plan contemplated, albeit fancifully, that spent nuclear fuel would be stored at the SONGS ISFSI for at least 30 years, Holtec only warranted its storage system for 10 years. *See* **Exhibit 7**.

14. Moreover, the Holtec dry storage canisters in which the spent nuclear fuel is being stored at the SONGS ISFSI are defective and unfit for the indefinite storage of spent nuclear fuel. Each and every one of the 73 individual canisters will contain more deadly radioactive Cesium-137 than was released globally during the Chernobyl disaster, as well as dozens of other radioactive and toxic fission byproducts. The failure of even one of these canisters will have calamitous consequences. Severe problems with Licensees' decommissioning plan make this nightmare scenario a real possibility.

15. First, although the radioisotopes in each canister remain radioactive, toxic, and deadly for hundreds of years (and one, Plutonium-239, remains deadly for over 24,000 years), Holtec warrants the canisters for only 25 years. *See* **Exhibit 7**. Thus, the warranty on the canisters will expire long before 2049, when Licensees unreasonably assume that all spent fuel will be transferred to permanent storage, and there is no objective basis for

determining that the canisters will remain viable beyond 2049, even though they will likely remain in the SONGS ISFSI indefinitely.

16. Second, the design of the Holtec canisters the Licensees are using to store the spent nuclear fuel deviates from the acceptable minimum safety thresholds required for the design and manufacture of nuclear waste storage containers. Indeed, the Holtec canisters are so-called "thin-wall" canisters with only a 5/8-inch thick stainless-steel wall with an aluminum egg-crate structure designed to hold up to 37 spent fuel assemblies. Holtec designs, manufactures, and supplies the canisters under strict guidelines promulgated by the NRC and, more important, under the conditions of applicable certificates of compliance ("CoCs"). *See* **Exhibit 8**. The NRC issues a CoC conditioned on the holder strictly hewing to specific technical specifications and approved contents and design features. But after receiving CoCs for the thin-wall canisters being used at SONGS, Holtec secretly modified the design and manufacture of the canisters, apparently to reduce manufacturing costs and/or to correct a flaw in the original design. By making the change surreptitiously, Holtec avoided a costly and time-consuming NRC design review and attendant risk analysis. In any case, the design change introduced a critical flaw into the casks that is discussed in further detail below.

17. Third, due to the design of the canisters, the narrow slots in which they are loaded into the storage system, and the equipment used to load the canisters into the storage system, extensive gouging of the canisters occurs during routine loading into the storage system. Over time, the gouges in the canisters can grow into deeper cracks that make the canisters susceptible to leaking and make it impossible for the canisters to be safely removed from the ISFSI in the future. However, there is no way to adequately monitor or inspect the canisters once they are in the ground, and no way to fix them even if critical damage to them could be identified.

IV. NRC GRANTS A LICENSE AMENDMENT THAT PERMITS DECOMMISSIONING OF SONGS ACCORDING TO LICENSEES' FLAWED DECOMMISSIONING PLAN

18. Because the original license granted to the Licensees was narrow in scope—in that it only permitted them to operate the plant and temporarily store spent nuclear fuel and waste—a license amendment would be necessary to decommission the plant. However, when Licensees decided to permanently cease nuclear operations, they sought to utilize the nuclear power plant for an entirely different purpose—that is, the long-term storage of spent nuclear fuel. Thus, the grant or denial of the Licensees' request for a license amendment was a matter of significant public concern, requiring an opportunity for meaningful public participation.

19. Without meaningful public participation or an independent assessment, on July 17, 2015, the NRC granted Licensees' request for a license amendment that permitted them to begin decommissioning the SONGS facility. *See* **Exhibit 9**. Specifically, the NRC authorized Licensees to "Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition." *Id*. In so doing, the NRC "found" that there was "reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations." *Id*. In fact, the NRC simply relied on Licensees' own flawed analysis instead of objective criteria or independent analysis, enabling Licensees to present their internal, untested, and unchecked conclusions, without even a suggestion of an objective analysis or oversight.

20. In addition, the NRC repeatedly granted Licensees' numerous subsequent license amendments and exemptions, regardless of the scope and magnitude of the proposed changes. *See* **Exhibit 10**. Among these exemptions was a staggering reduction in the amount of onsite liability insurance required to be maintained by Licensees from the $1.06 billion required by NRC regulations to a paltry $50 million. *See* **Exhibit 11**.

V. LICENSEES' MULTIPLE DECOMMISSIONING DISASTERS

21. From the outset, Licensees' decommissioning operations have been marred by a series of miscues, lackadaisical managerial oversight, and attempts to conceal the same. Unsurprisingly, this behavior has caused Licensees to repeatedly fall short of the NRC's identified standards and promulgated regulations. Among the many failures of the Licensees' decommissioning efforts are the following:

A. Licensees compromised the structural integrity of twenty-nine canisters they buried at SONGS.

22. Licensees have consistently used fewer personnel than necessary to ensure that the Holtec canisters are safely and effectively loaded into the ISFSI. For example, Licensees have employed an inadequate number of "spotters" at different vantage points, resulting in limited visibility of the canister as it is being loaded into its enclosure. This negligent deviation from safe fuel-handling procedures has already caused substantial harm to the millions of people around the SONGS facility. *See* **Exhibit 12**.

23. On information and belief, and as revealed in NRC documents and noted at public hearings, the Licensees negligently gouged and then buried twenty-nine (29) fully loaded canisters at SONGS. Experts believe this gouging may lead to deeper, through-the-wall cracks, which will make the future safe movement of these canisters impossible (despite the fact that the safety of the canisters' storage location is only warranted for 10 years). Experts also point out that damage to the canisters will be exacerbated, *inter alia*, by the presence of salt air, fog, rain, and salt water—the precise weather conditions that the canisters will be exposed to at the current location just steps from the Pacific Ocean. *See* **Exhibit 6**.

24. Upon information and belief, many (if not all) of the canisters were negligently scratched during transportation to the ISFSI. According to an NRC inspection report, and as admitted at a Community Engagement Panel Meeting by NRC spokesperson Scott Morris, **every single canister was damaged** during the downloading process: "The canister involved in the near-drop event [and] all the other canisters . . . experienced a little

bit of scuffing, and a little bit of contact going into the ISFSI." *See* **Exhibit 13**. As discussed below, one NRC inspector concluded that the damage to the canisters during loading into the SONGS ISFSI caused them to fall out of compliance with requirements of the applicable CoC. *See* **Exhibits 27 and 29**. The NRC, however, simply ignored this assessment and cleared the way for even more defective and non-compliant canisters to be buried at SONGS.[1]

B. Licensees nearly dropped two 49-ton canisters full of deadly radioactive nuclear waste and attempted to cover it up.

25. On July 22, 2018, Licensees nearly dropped a 49-ton canister full of deadly radioactive nuclear waste more than 18 feet into the ISFSI when it was caught on a quarter inch thick steel guide ring. Licensees referred to this event as an "unsecured load event." In actuality, this event could have turned San Onofre State Beach Park into a permanently uninhabitable nuclear wasteland.

26. Pursuant to 10 C.F.R. § 72.75, any incident involving nuclear waste ***must*** be reported to the NRC within ***twenty-four hours***, yet the July 22 failure was not formally reported on the NRC's Event Notifications Report. The sole purpose of 10 C.F.R. § 72.75 is to insure that potentially hazardous events are promptly reported and investigated and to allow for public disclosure of potential safety risks.

27. Despite the regulation's clear obligation to provide a formal written report for events of this nature, Licensees ***never*** provided a formal report for the July 22 unsecured load event. As a result, the public was kept in the dark about the potentially disastrous incident in July.

28. Ten days later, on August 3, 2018, the Licensees once again lost control of a 49-ton canister full of deadly radioactive nuclear waste while it was being lowered into a

[1] Despite the Licensees' efforts to downplay the significance of the gouging found on Holtec canisters, the potential consequences are staggering. Holtec's CEO admitted as much during a public meeting, acknowledging that even a microscopic crack in a canister is enough to cause a release of "millions of curies of radioactivity." *Dr. Kris Singh, CEO, Holtec International, on Dry Canister Nuclear Waste Storage*, YouTube (Oct. 14, 2014), at 31:04-34:30(at https://www.youtube.com/watch?v=s5LAQgTcvAU). *See* **Exhibit 14**.

below-ground storage silo. While moving the canister, Licensees' employees snagged the 49-ton canister on the same quarter-inch wide steel flange that captured the canister during the July 22 event. Licensees' personnel did not realize that the equipment holding the canister had been caught on the flange.

29. A whistleblower, David Fritch, came forward and publicly reported the event six days later during the August 9 Community Engagement Panel Meeting. Prior to the whistleblower's disclosure, Licensees' representative did not disclose the August 3 "near-miss" disaster when discussing the work stoppage put in place after the event. In fact, Edison's then Vice President and Chief Nuclear Officer, Tom Palmisano, affirmatively misled the public and misrepresented that the work stoppage was a planned stop so that they could perform necessary maintenance, provide employees with time off, and analyze the overall efficiency and effectiveness of the decommissioning process at that point.

30. However, during the public comment portion of the event, Fritch (a Safety Professional employed as a contractor at the SONGS facility) disclosed the misconduct as the actual cause for the work stoppage. Fritch informed the public about the near-miss event of August 3rd, and directly contradicted Licensees' public statements that the work stoppage was a "planned event."

31. Fritch's whistle-blowing sparked widespread media attention on the safety hazards posed by the Defendants' negligence at the facility. This alone should have prompted the NRC to perform a professional and independent risk assessment to determine the actual risks at the site, and take appropriate remedial steps to avoid or minimize future risks. Again, however, the NRC abdicated its responsibilities and continued to do nothing to protect the public or adequately monitor the situation.

32. As before, the Licensees failed to issue an NRC Event Notification Report within twenty-four hours of the Friday, August 3 event as required the NRC's regulations. Instead, they waited more than six weeks to report the incident. Moreover, rather than submitting the legally required written report, Licensees waited until Monday, August 6, to informally call the NRC. Licensees' private phone call deprived the public not only of

a written contemporaneous report of the near fatal disaster but prevented transparency of their actions at SONGS. This oral notification both failed to comply with the NRC's own "Event Reporting Requirements" under 10 CFR § 72.75, and failed to notify the public of the significant public safety hazards being posed by Licensees' decommissioning operations. In this way, Licensees attempted to keep the August 3 near-catastrophic-miss a secret.

33. This concealment was not accidental. In fact, the July 22 and August 3 near-miss events occurred during a required public comment period for the California State Lands Commissions Draft Environmental Impact Report ("EIR") directly related to the SONGS decommissioning project. That period ran from June 28 until August 30. By delaying formal written notice of the events, Licensees were able to avoid meaningful public participation in connection with the interrelated EIR.

34. Rather than taking precautionary steps to protect the public in light of the Licensees' demonstrated negligence, upon information and belief, the NRC completely deferred to Licensees and blindly relied upon their assurances that everything was under control. Indeed, the NRC went so far as to summarily reject a written request by Congressman Mike Levin for the installation of permanent NRC inspectors at the facility. *See* **Exhibit 15**.

35. On August 17, 2018, in response to the August 3 "near-miss," the NRC issued an Inspection Charter for SONGS, which found five violations that were ultimately penalized by the imposition of a wrist-slapping fee of $116,000 on Edison. *See* **Exhibits 16 and 17**. Perhaps more troubling, the NRC has not required Licensees to file an Event Notification Report for the July 22 event, and has ignored their flagrant violation of federal law for not filing an Event Notification Report for 47 days after the August 3 event.

36. Instead of ordering the Licensees to cease operations at SONGS, the NRC seemingly accepted the Licensees' "verbal commitment" to discontinue loading until the NRC issued its final Inspection Report.

VI. HOLTEC'S SURREPTITIOUS REDESIGN OF THE DRY STORAGE CANISTERS

37. In February 2018, while preparing to load one of the thin-wall canisters with spent nuclear fuel, Licensees discovered a loose bolt inside. After reporting the issue to Holtec, Holtec revealed that it had redesigned the already defective canisters to include a different "stand-off shim." The purpose of these shims is to enhance convection cooling of the hot fuel assemblies by creating additional space to allow cooling helium gas to flow throughout the canister so that the spent nuclear fuel does not overheat. The newly designed shims included bolts that were not part of the original design. As Licensees discovered, the newly introduced bolts are susceptible to breaking loose inside the canister, which could ultimately cause a restriction of airflow within the canister and a failure of the canister's cooling mechanism. Left uncooled, spent nuclear fuel will heat up to the point of a critical—and deadly—nuclear reaction. Thus, a failure of the canister's cooling mechanism would be disastrous.

38. Under NRC regulations, Holtec was required to obtain a CoC amendment prior to implementing any proposed change to the design of its canisters if the change would result in more than a minimal increase in the frequency or likelihood of an accident, malfunction, or the consequences of such accident or malfunction. Despite the serious risks posed by Holtec's design changes, however, Holtec failed to even notify the NRC, much less obtain a CoC amendment, before changing the design of the canisters.

39. On March 22, 2018, Licensees' admitted during a Community Engagement Panel Meeting that four canisters with the defective shim design had already been filled with spent nuclear fuel and buried at SONGS. To make matters worse, Mr. Palmisano made a stunning admission that there is no existing method for safely opening defectively designed canisters to see if the stand-off shims were broken in the four buried canisters. Thus, the SONGS Defendants have no way of ensuring that the fuel assemblies and/or cooling mechanisms have not been critically compromised. Mr. Palmisano admitted that

it would be at least three years before the techniques necessary to unload and inspect a canister ***could possibly*** be developed:

> So nobody has unloaded a commercial canister, either a bolted cask or a welded cask or canister. . . . What you would do is basically have a mechanism, either to do it in a fuel pool or do it in a dry transfer facility. . . . The real challenge as we would understand it today, and nobody has had to do it yet, is the reflood. Certainly, technically possible. What I would tell you is just I was back in Washington with the NRC last week, if you were just to brainstorm, ***this would probably be a two- to three-year project to develop the techniques***, pile up the techniques. The NRC would want to have explicit approval on this because of the ***radiological hazards***.

See **Exhibit 18** (emphasis added).

40. Although the NRC found that Holtec failed to establish adequate design control measures of components important to safety, and failed to perform evaluations before making the design changes, it failed to impose any fine or other penalty on Holtec for these violations.

41. Notably, this was not the first time Holtec flouted its obligations to disclose critical information to a regulator. In October 2010, Holtec was "debarred" as a contractor by the Tennessee Valley Authority ("TVA") in connection with improper and undisclosed payments made to a federal official to secure a contract to design and construct a dry cask storage system for spent nuclear fuel rods at the Brown Ferry Nuclear Plant. *See* **Exhibit 25**. Following that debarment, Holtec sought a $260 million tax break related to a nuclear plant project in Camden New Jersey. As part of that process, Holtec's CEO Kris Singh submitted certified forms where he answered "no" to the question of whether Holtec had ever been barred from doing business with a state or federal agency. In June 2019, New Jersey regulators froze Holtec's $260 million tax-incentive award pending further investigation. *See* **Exhibit 26**. Despite Holtec's history of misconduct and deceit, the NRC has continued to blindly accept its representations regarding its defective and dangerous canisters and has approved multiple amendments to the applicable CoCs to permit the continued use of Holtec's defective and dangerous canisters at SONGS and elsewhere.

VII. LICENSEES' UPDATED, BUT NO LESS FLAWED, DCE, AND DECOMMISSIONING FUNDING STATUS REPORTS

42. As required by the California Nuclear Facilities Decommissioning Act of 1985, Licensees updated their DCE for SONGS Units 2 & 3 in 2017. *See* **Exhibit 19**. Although Licensees' updated DCE continued to estimate that all spent nuclear fuel will be removed from the SONGS ISFSI by 2049, and that the site will be acceptable for unrestricted use by the end of 2051, Licensees changed their assumptions regarding the date the DOE will commence accepting spent nuclear fuel from the industry. Specifically, Licensees' 2017 DCE assumed the DOE will begin accepting spent nuclear fuel from the industry in 2028, rather than 2024, because of the "DOE's continued failure to perform its contractual obligation to remove spent fuel from commercial nuclear reactors in the past four years." Licensees' 2017 DCE does not explain, however, why pushing back the estimated date on which the DOE will begin accepting spent nuclear fuel from the industry by four years would not also necessitate pushing back the estimated date for removal of all spent nuclear from the SONGS ISFSI by four years and concomitantly increasing the estimated cost of storing that fuel for an extra four years. Nor does Licensees' 2017 DCE provide any objective evidence supporting its updated assumption that the DOE will, in fact, begin accepting spent nuclear fuel from the industry in 2028.

43. In subsequent decommissioning funding status reports submitted to the NRC, Licensees repeated this updated assumption regarding the date on which the DOE will begin accepting spent nuclear fuel from the industry. *See* **Exhibits 20 and 21**. Specifically, Licensees' status reports expressly acknowledge that the "current site-specific decommissioning cost estimates for San Onofre Unit 1 and San Onofre Units 2 and 3 assume that the DOE will commence transporting fuel in 2028." As in the 2017 DCE, however, Licensees' status reports do not provide any basis for the 2028 assumption, nor do they explain how pushing back the estimated date on which the DOE will begin accepting spent nuclear fuel from the industry would not also necessitate pushing back the date for removal of all spent nuclear fuel from SONGS and concomitantly increasing the

estimated cost of storing that fuel for an extra four years. Notably, however, Licensees' status reports do effectively acknowledge that their fundamental assumptions regarding the DOE's acceptance of spent nuclear fuel are uncertain at best. Indeed, the status reports expressly state that the 2028 assumption "may be updated periodically due to the ongoing uncertainties regarding the availability of a permanent repository for spent fuel."

VIII. DESPITE SERIOUS PUBLIC CONCERNS AND HAZARDOUS CONDITIONS THE NRC PERMITS LICENSEES TO RESUME DANGEROUS BURIAL OF SPENT NUCLEAR FUEL

44. In March 2019, an NRC inspector, Lee Brookhart, issued an internal report concluding that the damaged and defective Holtec canisters would require a formal design change, approved by the NRC, if they were to continue in service under the applicable CoCs, which require loading into the ISFSI to be accomplished without any scratching or damage to the canisters. *See* **Exhibits 27 and 29**. On May 21, 2019, however, the NRC disregarded Mr. Brookhart's warnings, Licensees' string of poor project oversight, Holtec's history of incompetence and malfeasance, and the fanciful assumptions underlying Licensees' entire decommissioning plan, and announced its determination that burial of spent nuclear fuel could continue at SONGS. *See* **Exhibit 22**. Thereafter, in July 2019, Licensees resumed their decommissioning operations, including the burial of spent nuclear fuel at the SONGS ISFSI.

45. Given the uncertainty surrounding the renewed canister burial, as well as litigation seeking to halt the process pending development of a record, Counsel for Petitioner—on September 6, 2019—requested that Licensees briefly abate further interment. *See* **Exhibit 23**. Licensees declined the request and are apparently poised to "continue the transfer operations" and complete the burial of spent nuclear fuel at SONGS as fast as possible. *See* **Exhibit 24**; *see also* **Exhibit 15**.

GROUNDS FOR ORDER IMMEDIATELY SUSPENDING DECOMMISSIONING OPERATIONS

I. APPLICABLE STANDARDS

46. Under 10 C.F.R. § 2.206, "Any person may file a request to institute a proceeding pursuant to § 2.202 to modify, suspend, or revoke a license, or for any other action as may be proper." Upon the filing of a petition under § 2.206, the NRC "may institute a proceeding to modify, suspend, or revoke a license or take such other action as may be proper by serving on the licensee or other person subject to the jurisdiction of the Commission an order that will," among other things, "[a]llege the violations with which the licensee or other person subject to the Commission's jurisdiction is charged, or the potentially hazardous conditions or other facts deemed to be sufficient ground for the proposed action, and specify the action proposed." Petitioner respectfully requests that the NRC issue an order immediately suspending all decommissioning operations at SONGS, including the burial of spent nuclear fuel at the SONGS ISFSI, and requiring Licensees to submit an amended decommissioning plan that properly accounts for the reality that the spent nuclear fuel being buried at SONGS will remain there indefinitely.

II. LICENSEES' BURIAL OF SPENT NUCLEAR FUEL AT SONGS POSES AN IMMINENT THREAT TO PUBLIC SAFETY

47. As detailed above, Licensees are burying hundreds of tons of deadly spent nuclear fuel in thin-wall canisters that cannot be loaded into the storage system without being critically damaged, and cannot be monitored, inspected, repaired, or safely removed once they are loaded. Moreover, at least some of the canisters were surreptitiously redesigned in a way that makes them even more susceptible to failure, and there is no way for anyone to determine whether or when those canisters might fail and cause a nuclear disaster. To make matters worse, Licensees have a proven track record of negligence, if not recklessness, in their past attempts to load the canisters into the SONGS ISFSI, nearly dropping a 49-ton canister full of spent nuclear fuel on at least two occasions.

48. As if this weren't enough, Licensees have elected to bury these defective canisters in perhaps the most hazardous location possible—merely 108 feet from, and only

inches above, a rising Pacific Ocean, in a tsunami zone surrounded by active fault lines, and in a humid environment that is likely to corrode and cause stress-induced cracking of the canisters' outer walls.

49. In other words, the SONGS ISFSI is a proverbial "ticking time bomb," and it is not a matter of whether a nuclear disaster will occur at the site, but a matter of when and how damaging the nuclear disaster will be. Accordingly, the NRC should immediately suspend all decommissioning operations at the SONGS site, including, and especially, the continued burial of spent nuclear fuel, and require Licensees to submit a proposed decommissioning plan that will not pose an imminent threat to public safety.

III. LICENSEES' ESTIMATED COST OF DECOMMISSIONING SONGS IS BASED ON UNREASONABLE AND FUNDAMENTALLY FLAWED ASSUMPTIONS

50. The fundamental premise for Licensees' various decommissioning cost estimates is that the spent nuclear fuel being buried at SONGS will remain there only temporarily. Indeed, Licensees initial DCE was based on the assumption that the DOE will begin accepting spent nuclear fuel from the industry in 2024 and that all spent nuclear fuel will be permanently removed from SONGS by 2049. Accordingly, Licensees' have allocated only enough funds to store and monitor spent nuclear fuel at SONGS through 2049.

51. Both Licensees and the NRC know full well that these assumptions are unreasonable and untethered to reality because there is currently no viable plan for the DOE to construct a permanent repository for spent nuclear fuel and there is certainly no plan or intention for the DOE to begin accepting spent nuclear fuel from the industry in 2024. In fact, the NRC states in its own publications that, although it "considers that 25 to 35 years is a reasonable timeframe for repository development, it acknowledges that there is sufficient uncertainty in this estimate that the possibility that more time will be needed cannot be ruled out." *See* **Exhibit 28**.

52. Although Licensees' 2017 DCE and decommissioning funds status reports push back to 2028 the assumed date on which the DOE will begin accepting spent nuclear

fuel from the industry, this is no more realistic or supported by any actual evidence than the initial 2024 estimate. Furthermore, this updated assumption renders Licensees' cost estimates even more fanciful, because, while they push back the date on which they assume the DOE will begin accepting spent nuclear fuel from the industry, they inexplicably maintain the assumption that all spent nuclear fuel will be permanently removed from SONGS by 2049.

53. By unreasonably assuming that all spent nuclear fuel will be permanently removed from SONGS by 2049, and only allocating sufficient funds to store and monitor the spent nuclear fuel at the site through that date, Licensees grossly understate the full cost of decommissioning SONGS and storing and monitoring spent nuclear fuel at the site through the termination of the SONGS licenses. Among other things, Licensees' cost estimates fail to account for the costs associated with: (1) storing and monitoring fuel beyond 2049 and perhaps permanently; (2) replacing and/or repairing canisters that have degraded, been damaged, and/or outlived their 40-year certifications; and (3) transferring canisters to another location when the storage system itself inevitably degrades and becomes unfit for storage of spent nuclear fuel. Accordingly, the NRC should suspend all decommissioning operations currently underway at SONGS and require Licensees to submit a new decommissioning cost estimate that is grounded in the reality that spent nuclear fuel will be stored at SONGS indefinitely.

IV. LICENSEES' FLAWED DECOMMISSIONING PLAN POSES A LONG TERM THREAT TO PUBLIC SAFETY

54. By falsely assuming that spent nuclear fuel will be stored at SONGS only temporarily, Licensees have not only understated the total cost associated with their decommissioning operations but they have set a disaster off on the horizon that will be unavoidable if not addressed immediately. As already discussed at length, Licensees' entire decommissioning plan, including all decisions related to the location of the SONGS ISFSI, the selection of the Holtec storage system and canisters, and the estimated cost of

decommissioning and monitoring spent fuel at SONGS, are predicated on the false assumption that spent nuclear fuel will be stored at SONGS only temporarily.

55. Licensees selected a storage system with an extremely limited warranty and usable life based on the false assumption that it will be empty and demolished in thirty years. Licensees selected defective canisters with limited warranties that cannot be safely replaced when damaged based on the false assumption that the DOE would be removing them in thirty years. And Licensees selected a hazardous storage location near a rising sea based on the false assumption that the spent nuclear fuel will be permanently removed by the time the storage facility is underwater. If the NRC does not suspend decommissioning operations now, these fanciful assumptions will inevitably lead to a disastrous reality for the millions of people who reside in the vicinity of SONGS. Accordingly, the NRC should immediately suspend all decommissioning operations at SONGS, including and especially the burial of spent nuclear fuel in the SONGS ISFSI, and require Licensees to submit a new decommissioning plan that is grounded in the reality that the spent nuclear fuel being buried at SONGS will remain there indefinitely, if not permanently.

V. THE NRC'S FAILURE TO PREPARE AN ENVIRONMENTAL ASSESSMENT OR SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT PRIOR TO APPROVING DECOMMISSIONING ACTIVITIES VIOLATES NEPA AND THE APA

56. The NRC failed to prepare either an environmental assessment ("EA") or an environmental impact statement ("EIS") prior to issuing the July 17, 2015 license amendment or otherwise approving decommissioning activities at SONGS Units 2 and 3, in violation of the National Environmental Policy Act ("NEPA"), the Administrative Procedure Act ("APA"), and the NRC's own regulations.

57. NEPA requires all federal agencies to conduct environmental evaluations of any "major federal actions significantly affecting the quality of the human environment." 42 U.S.C. § 4332(2)(C). "Major federal actions" are defined broadly to include "new and continuing activities, including projects and programs entirely or partly financed, assisted, conducted, regulated, or approved by federal agencies." 40 C.F.R.

§ 1508.18. When an agency is uncertain whether a proposed action will significantly affect the environment, it must prepare an EA to determine whether the preparation of a more detailed EIS is necessary. 40 C.F.R §§ 1508.9(a), 1508.13 (2009); *see also California Wilderness Coal. v. U.S. Dep't of Energy*, 631 F.3d 1072, 1097 (9th Cir. 2011) ("If the proposed action does not categorically require the preparation of an EIS, the agency must prepare an EA to determine whether the action will have a significant effect on the environment."). In either case, NEPA obligates federal agencies to take a "hard look" at the potential environmental consequences of proposed actions. *California Wilderness Coal.*, 631 F.3d at 1097 (9th Cir. 2011).

58. The NRC's issuance of a license amendment and approval of decommissioning activities at SONGS Units 2 and 3 constituted a "major federal action" that required NEPA compliance. As an initial matter, the NRC has historically prepared either an EA or EIS upon issuing a license amendment at SONGS Units 2 and 3. In 1981, the NRC prepared an EIS when it issued the initial operating license to Edison for Units 2 and 3. *See* **Exhibit 30**. The NRC then prepared EAs each time it amended the license. For example, in 1996, it prepared an EA prior to approving a license amendment to allow an increase in fuel enrichment. *See* **Exhibit 31**. In 2001, it prepared an EA prior to approving a license amendment to allow Edison to increase its maximum reactor core power level. *See* **Exhibit 32**. And in 2015, it prepared an EA prior to approving an amendment allowing security personnel to use certain firearms and ammunition on site. *See* **Exhibit 33**. The NRC's failure to prepare either an EA or EIS prior to issuing a license amendment and approving decommissioning activities is contrary to its prior practice at SONGS.

59. Furthermore, the NRC's own regulations and guidance documents state that the NRC will prepare an EA or EIS prior to authorizing decommissioning. The NRC's regulations provide that "[i]n connection with the amendment of an operating or combined license authorizing decommissioning activities . . . the NRC staff will prepare a supplemental environmental impact statement for the post operating or post combined

license stage or an environmental assessment." 10 C.F.R. part 51.95(d). Similarly, the NRC's Environmental Review Guidance for Licensing Actions Associated with NMSS Programs NUREG-1748 (2003) states that the NEPA review process is "usually initiated by . . . a decommissioning plan submitted to the NRC." *See* **Exhibit 34** at 1-2.

60. Numerous federal courts have also noted that "decommissioning is an action which, even under the [NRC's] new policy, requires NEPA compliance." *See, e.g.*, *Citizens Awareness Network, Inc. v. U.S. Nuclear Regulatory Comm'n*, 59 F.3d 284, 293 (1st Cir. 1995); *see also New Jersey v. U.S. Nuclear Regulatory Comm'n*, 526 F.3d 98, 103 (3d Cir. 2008) ("[T]he NRC will conduct site-specific environmental analyses when licensees decommission…"); *see also Benton Cty. v. U.S. Dep't of Energy*, 256 F. Supp. 2d 1195, 1202 (E.D. Wash. 2003) ("Prior to committing any resources to any one of the options for decommissioning, the [agency] must prepare an EIS."). Thus, the NRC was required to prepare either an EA or EIS prior to approving the Decommissioning Plan.

61. The NRC partially discharged its duty to comply with NEPA prior to decommissioning through the Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities, NUREG-0586 (1988), as supplemented by NUREG-0586, Supplement 1 (2002) (collectively, the "Decommissioning GEIS"). *See* **Exhibit 35**. The generic EIS analyzed the environmental impacts of decommissioning that are common to all sites. But the Decommissioning GEIS concluded that a site-specific supplemental EIS would be necessary to evaluate non-generic issues, such as the environmental impacts of decommissioning on environmental justice and threatened and endangered species:

> The staff has considered available information on the potential impacts of decommissioning on environmental justice, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has considered that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis . . . . Subsequent to the submittal of the PSDAR, the NRC staff will consider the impacts related to environmental justice from decommissioning activities.

See **Exhibit 35** Supp. 1 at 4-65.

> The staff has considered available information on the potential impacts of decommissioning on threatened and endangered species, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has considered that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis.

See **Exhibit 35** Supp. 1 at 4-30. The NRC's regulations and guidance documents purport to fill these gaps in the Decommissioning GEIS by requiring the NRC to prepare either an EA or supplemental EIS prior to approving a decommissioning plan. *See, e.g.*, 10 C.F.R. 51.95(d). The NRC, however, failed to prepare either an EA or supplemental EIS when it approved Edison's license amendment and authorized decommissioning at SONGS Units 2 and 3.

62. The City of Laguna Beach ("City") notified the NRC of this failure to comply with NEPA at SONGS in its August 12, 2016 letter. *See* **Exhibit 36**. Notably, the California State Lands Commission ("CSLC") correctly determined that the decommissioning activities required the CSLC to prepare an Environmental Impact Report ("EIR") under California's Environmental Quality Act ("CEQA"), which is the State of California's NEPA analog. In connection with preliminary scoping of the CSLC EIR, the City insisted that the NRC prepare a supplemental EIS, as required by NEPA, or alternatively prepare a joint EIS with the CSLC, as authorized by NEPA's implementing regulations. *See* 40 C.F.R. 1506.2. The City expressed specific concern over the following issues:

- The NRC has not considered the environmental and safety effects of sea level rise caused by climate change.
- The NRC has not addressed the environmental impacts of decommissioning on environmental justice, threatened and endangered species, offsite land use, offsite aquatic and terrestrial ecology, and certain cultural and historic resources.

- The NRC has not approved the design of the Holtec UMAX system that Edison has proposed for the ISFSI and that a partially subterranean design may reduce radiation safety.

- The NRC has not addressed certain radiological safety concerns, such as the site-specific radiological safety concern of storing SNF in a seismically active marine environment, which is not addressed in the Decommissioning GEIS.

- The proposed changes and alterations to the SONGS facility's design associated with decommissioning, including the Spent Fuel Pool Island Project and the expanded and modified ISFSI, were never addressed in the SONGS Final Safety Analysis Report ("FSAR") and thus require a separate license amendment.

63. Despite the City's letter, the NRC failed to take corrective action. Instead, the NRC took the incorrect and inconsistent position that it was not required to prepare an EA or supplemental EIS in connection with approving decommissioning, because the "decommissioning activities remain within the scope of the Decommissioning GEIS [and] applicable site-specific NEPA analyses conducted in support of previous licensing actions." *See* **Exhibit 37**. Specifically, the NRC claimed that review of "site-specific environmental impacts (*i.e.*, those not dispositioned generically in the Decommissioning GEIS) are first addressed in the [1981 EIS]" and were additionally "analyzed in the EA/FONSIs for license amendment or exemption requests during the plant's operation," such as the 1996 EA, 2001 EA, and 2015 EA. But this is plainly untrue. The prior site-specific analyses at SONGS never addressed the potential environmental impacts of decommissioning. They addressed the potential environmental impacts of the proposed actions stated therein (*e.g.*, a license amendment to allow security personnel to carry certain ammunition on-site). *See* **Exhibit 33**. These prior analyses do not act to satisfy the NRC's duty to prepare a site-specific supplemental EIS for non-generic decommissioning issues, as contemplated by the Decommissioning GEIS and NRC.

64. This is not the first time the NRC has failed to comply with its own regulations in the context of preparing site-specific supplemental EISs that tier off of a

generic EIS. In August 2013, the Office of the Inspector General ("OIG") audited the NRC's NEPA compliance and concluded that the NRC had an "incorrect understanding of the regulations related to scoping for EISs that tier off of a generic EIS." *See* **Exhibit 38** at 24. The issue here is similar. The NRC's reasoning for refusing to prepare a supplemental site-specific EIS is based on an incorrect understanding of its own regulations and the role of the Decommissioning GEIS.

65. The NRC's failure to prepare either an EA or supplemental EIS prior to approving Edison's license amendment and authorizing decommissioning at SONGS Units 2 and 3 is contrary to the Decommissioning GEIS, NRC regulations, and federal court opinions. In addition, it violates NEPA, 42 U.S.C. § 4332(2)(C), and constitutes arbitrary and capricious conduct under the Administrative Procedure Act, 5 U.S.C. § 706. Petitioner therefore requests that the NRC immediately suspend all decommissioning operations at SONGS and prepare a supplemental EIS that evaluates site-specific environmental issues not addressed in the Decommissioning GEIS or prior site-specific NEPA analyses, such as the those issues referenced herein. In so doing, the NRC should (1) discuss mitigation measures the agency could take to reduce environmental impacts; (2) discuss the direct, indirect, and cumulative impacts that may result from decommissioning activities; and (3) ensure the use of "accurate scientific analysis" and "high quality" information. 40 C.F.R. §§ 1500.1(b), 1508.25(b).

Dated: September 24, 2019

BARNES & THORNBURG LLP

By: /s/ Charles G. La Bella
Charles G. La Bella
Attorneys for Plaintiff
Public Watchdogs

EXHIBIT 1

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Thomas J. Palmisano
Vice President & Chief Nuclear Officer

10 CFR 50.82(a)(4)(i)

September 23, 2014

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

Subject: **Docket Nos. 50-361 and 50-362,**
San Onofre Nuclear Generating Station, Units 2 and 3
Post-Shutdown Decommissioning Activities Report

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

Dear Sir or Madam:

On June 12, 2013, in accordance with 10 CFR 50.82(a)(1)(i), Southern California Edison (SCE) submitted the referenced letter to the U.S. Nuclear Regulatory Commission (NRC) certifying the permanent cessation of operations at San Onofre Nuclear Generating Station (SONGS), Units 2 and 3. In accordance with 10 CFR 50.54(bb) and 10 CFR 50.82(a)(4)(i), SCE is required to submit an Irradiated Fuel Management Plan (IFMP), Site Specific Decommissioning Cost Estimate (DCE) and Post-Shutdown Decommissioning Activities Report (PSDAR) within two years of permanent cessation of operations.

The SONGS, Units 2 and 3 PSDAR is attached. The SONGS, Units 2 and 3 IFMP and DCE are being concurrently submitted under separate cover letters. The descriptions of decommissioning activities and phases in the PSDAR are consistent with those described in the DCE. Both the PSDAR and DCE represent SCE's current plans and are subject to change as the project progresses.

Changes to significant details will be included in subsequent revisions to the PSDAR as required by 10 CFR 50.54(bb). Financial assurance information will be provided on an annual basis as required by 10 CFR 50.75(f)(1).

This letter does not contain any new commitments.

If there are any questions or if additional information is needed, please contact me or Ms. Andrea Sterdis at (949) 368-9985.

Sincerely,

P.O. Box 128
San Clemente, CA 92672
(949) 368-6575 PAX 86575
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A001
NRR

Enclosure: San Onofre Nuclear Generating Station Units 2 and 3 Post-Shutdown Decommissioning Activities Report

cc: M. L. Dapas, Regional Administrator, NRC Region IV
T. J. Wengert, NRC Project Manager, San Onofre Units 2 and 3 Decommissioning
R. E. Lantz, NRC Region IV, San Onofre Units 2 and 3
G. G. Warnick, NRC Senior Resident Inspector, San Onofre Units 2 and 3
S. Y. Hsu, California Department of Health Services, Radiologic Health Branch

San Onofre Nuclear Generating Station Units 2 and 3
Post-Shutdown Decommissioning Activities Report

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List of Acronyms and Abbreviations

AADT	Average Annual Daily Traffic
AIF	Atomic Industrial Forum
ALARA	As Low As Reasonably Achievable
BMP	Best Management Practices
CCC	California Coastal Commission
CFR	Code of Federal Regulations
CRWQCB	California Regional Water Quality Control Board
CSLC	California State Lands Commission
DBA	Design Basis Accident
DCE	Decommissioning Cost Estimate
Decon Pd	License Termination Period
DGC	Decommissioning General Contractor
DOE	United States Department of Energy
DOT	United States Department of Transportation
DSC	Dry Storage Canister
FES	Final Environmental Statement, SONGS Units 2 and 3 (NUREG-0490)
GEIS	Generic Environmental Impact Statement (NUREG-0586)
GTCC	Greater than Class C
HSM	Horizontal Storage Modules
IFMP	Irradiated Fuel Management Plan
ISFSI	Independent Spent Fuel Storage Installation
LTP	License Termination Plan
LLRW	Low Level Radioactive waste
MARRSIM	Multi-Agency Radiation Survey and Site Investigation Manual
MWDOC	Municipal Water District of Orange County
MWt	Megawatt-thermal
NEI	Nuclear Energy Institute
NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
ORISE	Oak Ridge Institute for Science and Education
PSDAR	Post-Shutdown Decommissioning Activities Report
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RV	Reactor Vessel
SONGS	San Onofre Nuclear Generating Station
SCE	Southern California Edison
SDAPCD	San Diego Air Pollution Control District
SFP	Spent Fuel Pool
SNF Pd	Spent Fuel Period
SFSM	Spent Fuel Storage Modules
SPCC	Spill Prevention Control and Countermeasures
SR Pd	Site Restoration Period
SSC	Structures, Systems, and Components
UFSAR	Updated Final Safety analysis Report
USCB	United States Census Bureau

I. INTRODUCTION AND SUMMARY

A. Introduction

1. Historical Perspectives

San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 have been owned by four entities. Two are municipalities (Riverside and Anaheim) and two are investor owned utilities: San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE, the Owner-Operator and agent for the participants). The relative obligation for operation and decommissioning varies by unit and entity. The term "SONGS Participants" is used in this report to represent the four entities that have continuing decommissioning obligations.

SONGS Unit 1 was shut down in 1992 with on-shore facilities largely dismantled by 2009 and off-shore conduits being fully dispositioned this year (2014). The decision has been made to shut down and decommission Units 2 and 3. Since the decision to shut down SONGS Units 2 and 3, the focus of SONGS staff and other personnel has been to plan and begin execution of the necessary steps to achieve timely, cost-effective, and safe decommissioning and restoration of the SONGS site.

In developing its plans, SONGS has benchmarked the experiences of commercial decommissioning projects in the 1990s and 2000s and has sought the input from experienced individuals and groups with a wide range of such experience. SONGS maintains close communications with those facilities currently undergoing decommissioning and with many of the organizations supporting those efforts. In particular, both the Zion and Humboldt Bay plants are currently undergoing active decommissioning. Three others (Kewaunee, Crystal River 3, and Vermont Yankee) are, or soon will be, entering SAFSTOR conditions of varying durations prior to dismantlement.

Earlier decommissioning projects faced a number of first-time technical challenges, such as cutting reactor vessel (RV) internals in a high radiation environment. SONGS' reviews indicate that many of the technical challenges confronting SONGS decommissioning now have mature solutions. Similarly, our predecessors provide a wealth of knowledge to minimize worker radiation exposure, efficiently plan, and sequence a decommissioning project and safely manage and transport waste.

The SONGS Participants have the responsibility to restore the site in accordance with applicable regulations and agreements. The SONGS Participants have a responsibility to their stakeholders and the communities they serve to do so in a transparent and effective manner while striving to attain high standards of safety and environmental protection. Further, the SONGS Participants will have a limited, if any, role in the future use of the site. The ultimate use for the site is for the land-owner (U.S. Navy) to determine with input from the community at large.

2. Community Engagement

A key lesson-learned in our review of other decommissioning projects is the continued importance of community engagement during the decommissioning process. The SONGS Participants are committed

to engaging the local community and its leaders in an open, transparent, and proactive manner. SONGS is actively engaged with external stakeholders to: understand their priorities; inform them of SONGS plans; and, to seek their input on the safe, timely, and cost-effective decommissioning of SONGS.

The SONGS Participants are actively engaging with the community through public outreach including briefings for community groups and routine educational updates for local, state, and federal officials. The SONGS participants have formed the Community Engagement Panel (CEP) with members representing a broad range of stakeholders to advise SONGS on decommissioning matters. The panel meets at least quarterly to facilitate dialogue and includes several representatives of government, members from academia, labor, business, environmental organization, and a local anti-nuclear leader. Members of the CEP were provided with the opportunity to review and provide input on this document as well as the Decommissioning Cost Estimate (DCE) and the Irradiated Fuel Management Plan (IFMP). As a precursor to review of these submittals, SONGS hosted two workshops with external technical experts to provide the CEP members with a depth of knowledge in these areas. Feedback from the panel was addressed prior to finalization and SCE senior management authorization of the submittals.

SONGS also has established a website, www.SONGScommunity.com, as a dedicated online source for information on the plant and the decommissioning process. The website includes background information on decommissioning, links to other websites including the NRC, and an "opt-in" feature that allows members of the community to register for automatic updates on decommissioning matters.

3. Regulatory Basis

In accordance with the requirements of 10 CFR 50.82, "Termination of License," paragraph (a)(4)(i), this report constitutes the Post-Shutdown Decommissioning Activities Report (PSDAR) for SONGS Units 2 and 3. The PSDAR contains the following:

1. A description of the planned decommissioning activities along with a schedule for their accomplishment.
2. A site-specific DCE including the projected cost of managing irradiated fuel and site restoration (being submitted concurrently).
3. A discussion that provides the basis for concluding that the environmental impacts associated with the site-specific decommissioning activities will be bounded by the appropriate previously issued generic and plant specific environmental impact statements.

The PSDAR has been developed consistent with NRC Regulatory Guide 1.185, Revision 1, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report." This report is based on currently available information; however, the plans discussed may be modified as additional information becomes available or as circumstances change. As required by 10 CFR 50.82(a)(7), SCE will notify the Nuclear Regulatory Commission (NRC) in writing before performing any decommissioning activity inconsistent with, or making any significant schedule change from, those actions and schedules described in the PSDAR, including changes that significantly increase the decommissioning cost.

The IFMP and DCE are being submitted concurrently with the PSDAR. The technical, schedule, and cost information provided is consistent among these submittals.

B. Background

The SONGS site is located on the coast of southern California in San Diego County, approximately 62 miles southeast of Los Angeles and 51 miles northwest of San Diego. The site is located entirely within the boundaries of the United States Marine Corps Base Camp Pendleton. The site is approximately 4,500 feet long and 800 feet wide, comprising 84 acres. The site does not include office buildings and related facilities located east of Interstate 5 (I-5) referred to as "the Mesa" or other adjacent parcels.

The property on which the station is built is subject to an easement from the United States Government through the U. S. Navy. The nearest privately owned land is approximately 2.5 miles from the site.

SONGS Units 2 and 3 is a two-unit site with supporting facilities. The reactors were previously licensed to produce 3,438 MWt each. An on-site Independent Spent Fuel Storage Installation (ISFSI) used to store SONGS Units 1, 2 and 3 fuel, located on the portion of the site previously occupied by SONGS Unit 1. Storage at the ISFSI was initiated in 2003 and the pad was subsequently (2007) expanded to support the currently placed 63 Horizontal Storage Modules in which 51 Dry Storage Containers (DSCs) have been installed to-date: 50 containing irradiated fuel and one (1) containing Greater-Than-Class-C (GTCC) materials. The most recent loading campaign was conducted in 2012. As discussed in the Spent Fuel Management Period details and the concurrently submitted IFMP, it will be necessary to further expand the current ISFSI capacity to store the complete inventory of Units 2 and 3 spent fuel. The location, capacity, and technology to be employed have not yet been finalized.

A brief history of the major milestones related to plant construction and operation is as follows:

	UNIT 2	UNIT 3
• Construction Permit Issued	October 18, 1973	October 18, 1973
• Operating License Issued	February 16, 1982	November 15, 1982
• Full Power Operation	June 15, 1983	November 18, 1983
• Final Reactor Operation	January 9, 2012	January 31, 2012

On June 7, 2013, SCE announced its decision to permanently cease power operations and decommission SONGS Units 2 and 3. By letter dated June 12, 2013 (Reference 3), SCE notified the NRC of its decision to permanently cease power operations. SCE has submitted two letters dated July 22, 2013 (Reference 5) and June 28, 2013 (Reference 4) certifying that fuel has been removed from the Unit 2 and 3 reactors, respectively.

Pursuant to 10 CFR 50.51(b), "Continuation of License," the license for a facility that has permanently ceased operations, continues in effect beyond the expiration date to authorize ownership and possession of the facility until the NRC notifies the licensee in writing that the license has been

terminated. During the period that the license remains in effect, 10 CFR 50.51 (b) requires the licensee to:

(1) Take actions necessary to decommission and decontaminate the facility and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition, and

(2) Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the provisions of the specific 10 CFR part 50 licenses for the facility.

C. Summary of Decommissioning Alternatives

The NRC has evaluated the environmental impacts of three general methods for decommissioning power reactor facilities in NUREG-0586, "Final Generic Environmental Impact Statement (GEIS) on Decommissioning Nuclear Facilities," Supplement 1 (Reference 6). The three general methods are:

- **DECON:** The equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the license after cessation of operations.
- **SAFSTOR:** The facility is placed in a safe stable condition and maintained in that state (safe storage) until it is subsequently decontaminated and dismantled to levels that permit license termination. During SAFSTOR, a facility is left intact or may be partially dismantled, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and then processed. Radioactive decay occurs during the SAFSTOR period, thus reducing the levels of radioactivity in and on the material and potentially the quantity of radioactive material that must be disposed of during the decontamination and dismantlement.
- **ENTOMB:** Radioactive structures, systems, and components are encased in a structurally long-lived substance such as concrete. The entombed structure is appropriately maintained and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.

The SONGS Participants have chosen the DECON method. SONGS is currently in the planning period during which the site is preparing for safe and orderly transition to dismantlement. More specifically:

- Permanent cessation of operations was announced on June 7, 2013.
- DECON methodology was selected (prompt decontamination and dismantlement after initial planning period).
- Additional ISFSI capacity will be added to meet all of the site's needs.
- Initial site characterization activities are underway.
- Plans to isolate the Spent Fuel Pools (referred to as "islanding") are in development.
- Other necessary actions to facilitate safe system retirement and removal (referred to as "cold and dark") are in development.

When the required regulatory reviews, planning, and preparation are sufficiently complete, the site will move into active decontamination and dismantlement. Current plans are for that period to overlap with completion of the relocation of spent fuel from the Spent Fuel Pools to the ISFSI.

The SONGS facility will be decontaminated and dismantled (D&D) to levels that permit termination of the NRC licenses and in accordance with the requirements agreed to by the United States Navy in the easement for the site. In support of this and in accordance with 10 CFR 50.82(a)(9), a License Termination Plan will be developed and submitted for NRC approval at least two years prior to termination of the license.

The decommissioning approach for SONGS is described in more detail in the following sections:

- Section II summarizes the planned decommissioning activities and general timing of their implementation.
- Section III summarizes the cost estimating methodology employed by Energy*Solutions* and references the site specific DCE being submitted concurrently.
- Section IV describes the basis for concluding that the environmental impacts associated with decommissioning SONGS Units 2 and 3 are bounded by the most recent site-specific environmental impact statement and NRC GEIS related to decommissioning.

II. DESCRIPTION OF PLANNED DECOMMISSIONING ACTIVITIES

The SONGS Units 2 and 3 decommissioning project is currently in the planning period transitioning to DECON as soon as necessary planning, approvals, and conditions permit doing so in a safe and cost-effective manner. DECON is defined in Section I.C of this report.

Table II-1 provides a summary of the current decommissioning plan and schedule for SONGS Units 2 and 3. The major decommissioning periods and general sequencing of the activities that will occur during each period identified in Table II-1 are discussed in more detail in the sections that follow. The periods are logical groupings of activities. The categories are also consistent with the Nuclear Decommissioning Trust (NDT) funds which are allocated based on specific regulatory requirements. The activities executed during these periods will, in many cases progress in parallel, and may not be as completely segregated as the description implies. For instance, while distinct decontamination and dismantlement activities are listed, it may be determined to be more effective from dose, labor, or waste disposal perspectives to dismantle structures and systems and dispose of them as radioactive waste rather than decontaminate them and dispose of the balance as non-radioactive waste.

The planning required for each decommissioning activity, including the selection of the process to perform the work, will be performed in accordance with appropriate governance and oversight processes. Based on current plans, no decommissioning activities unique to the site have been identified and no activities or environmental impacts outside the bounds considered in the GEIS have been identified. Appropriate radiological and environmental programs will be maintained throughout

the decommissioning process to ensure radiological safety of the workforce and the public and environmental compliance is maintained.

Table II-1
San Onofre Nuclear Generating Station Units 2 and 3
Current Schedule of Decommissioning Periods

Task Name	Start	Finish
Part 50 License Termination (other than ISFSI)		
Announcement of Cessation of Operations	06/07/2013	N/A
Decon Period 1 – Transition to Decommissioning	06/07/2013	12/31/2013
Decon Period 2 – Decommissioning Planning and Site Modifications	01/01/2014	06/30/2015
Decon Period 3 – Decommissioning Preps/Reactor Internals Segmentation	06/30/2015	06/01/2019
Decon Period 4 – Plant Systems and Large Component Removal	06/01/2019	09/24/2022
Decon Period 5 – Building Decontamination	09/24/2022	07/13/2024
Decon Period 6 – License Termination During Demolition	07/13/2024	12/24/2032
Spent Fuel Management		
SNF Period 1 – Spent Fuel Management Transition	06/07/2013	12/31/2013
SNF Period 2 - Spent Fuel Transfer to Dry Storage	01/01/2014	06/01/2019
SNF Period 3 – Dry Storage During Decommissioning – Units 1, 2 & 3	06/01/2019	12/05/2031
SNF Period 4 – Dry Storage Only – Units 1, 2 & 3	12/05/2031	12/31/2035
SNF Period 5 – Dry Storage Only – Units 2 & 3	12/31/2035	12/31/2049
SNF D&D Period 1 – ISFSI Part 50 License Termination	12/31/2049	05/06/2050
SNF D&D Period 2 – ISFSI Demolition	05/06/2050	09/08/2051
Site Restoration		
SR Period 1 – Transition to Site Restoration	06/07/2013	06/30/2015
SR Period 2 – Building Demolition During Decommissioning	06/30/2015	07/11/2017
SR Period 3 – Subsurface Demolition Engineering and Permitting	10/01/2019	07/13/2024
SR Period 4 – Building Demolition to 3 Feet Below Grade	07/13/2024	10/14/2028
SR Period 5 – Subgrade Structure Removal Below -3 Feet	10/14/2028	12/5/2031
SR Period 6 – Final Site Restoration and Easement Termination	05/06/2050	12/15/2051
Final Easement Termination	12/15/2051	N/A

Note [1]: Shipping dates are assumed based on the previously documented positions of the DOE, which indicates that shipments from the industry could begin as early as 2024 and SONGS place in the current queue. Both are subject to changes.

A. Detailed Breakdown of License Termination Periods

The License Termination Periods (referred to as decontamination periods) include those activities necessary to remove or reduce the levels of radioactive contamination to levels necessary to terminate the Part 50 licenses for the site (other than the ISFSI) and release it back to the Navy. Also included are the development, submittal, and support for the review of the primary decommissioning documents.

Periods 1 and 2 generally consist of planning and transition of the site to a condition where it is ready for significant decontamination and dismantlement activities. As detailed below, these periods include: system abandonment and isolation of the remaining structures, systems and components (SSC) from normal power and water sources. System abandonment and isolation allow the decontamination and dismantlement to proceed safely and in an efficient sequence. Additionally, the selection of the contractor for managing the bulk of the decommissioning activities will be made.

Period 3 is focused on decontamination and dismantlement of the major components in the containment building (RV internals, vessel, head, steam generators, pressurizer, and main piping).

Period 4 addresses the decontamination and dismantlement of SSCs known to be substantially contaminated and the removal of the components from both Periods 3 and 4.

Period 5 is focused on decontamination of the various buildings. As noted elsewhere it may be more appropriate to simply proceed with dismantlement if it is more timely and cost-effective to simply dispose of building material as radioactive waste.

Period 6 is focused on the final site survey to confirm that the site is acceptable for release back to the Navy. The process for doing so "Multi-Agency Radiation Survey and Site Investigation Manual" (MARRSIM) was developed by the four federal agencies having authority over radioactive materials (Department of Defense, Department of Energy, the Environmental Protection Agency and the NRC) and is the consensus standard endorsed by other stakeholders. Its application will be validated by the NRC.

Decontamination Period 1 – Transition to Decommissioning

- Announcement of Cessation of Operations
- Defuel Reactors
- Notification of Permanent Fuel Removal
- Disposition of legacy Low Level Radioactive Waste (LLRW)

Decontamination Period 2 – Decommissioning Planning and Site Modifications

- Preparation of Decommissioning Related Licensing Submittals
  - Permanently Defueled Technical Specifications (Submitted March 21, 2014)
  - Permanently Defueled Radiological Emergency Plan (Submitted March 31, 2014)
- Submit PSDAR, DCE and IFMP to NRC
- Perform Historical Site Assessment and Site Characterization
- Planning, Design, and Implementation of Cold and Dark (Site Repowering)
- Design and Install Spent Fuel Pool Islanding, Control Room Relocation, and Security Modifications
- Select Decommissioning General Contractor (DGC)

Decontamination Period 3 – Decommissioning Preparations and Reactor Internal Segmentation

- DGC Mobilization and Planning
- System Decontamination
- Reactor Internals Removal Preparations

- Reactor Internals Segmentation Planning and Implementation
- Purchase Dry Storage Canisters for GTCC Waste
- Segment and Package Reactor Internals for Storage in the ISFSI

Decontamination Period 4 – Plant Systems and Large Component Removal

- Upgrade Rail Spur in Owner Controlled Area
- Install Large Array Radiation Detection System to Monitor Shipments In/Out of Site
- Remove, Package, and Dispose of Non-Essential Systems
- Asbestos and Lead Abatement
- Spent Fuel Pool Closure
- Remove Spent Fuel Pool Racks, Spent Fuel Pool Island Equipment, and Bridge Crane
- Remove and Dispose of Legacy Class B and C Wastes
- Remove, Package, and Dispose of Essential Systems
- Removal and Disposal of Spent Resins, Filter Media, and Tank Sludge
- Large Component Removal
- Prepare License Termination Plan

Decontamination Period 5 – Building Decontamination

- Decontaminate Containment Buildings
- Decontaminate Turbine Buildings
- Decontaminate Fuel Handling Buildings
- Decontaminate Auxiliary Rad-waste Building
- Decontaminate Auxiliary Control Building
- Decontaminate Penetration Buildings
- Decontaminate Safety Equipment and Main Steam Isolation Valve (MSIV) Buildings
- Radiological Survey of Structures During Decontamination

Decontamination Period 6 – License Termination

- Final Status Survey
- Verification and NRC Approval

B. Detailed Breakdown of Spent Fuel Management Periods

The Spent Nuclear Fuel Management Periods began with all spent fuel off-loaded from the reactor vessel into the Spent Fuel Pools and the certification of permanent defueling letters submitted to the NRC in accordance with 10 CFR 50.82(a)(1)(ii) (References 4 and 5).

During Period 1 measures will be planned, designed, and implemented to ensure spent fuel storage and handling systems will continue to function to support fuel storage in the spent fuel pool and to facilitate transfer of the spent fuel to the ISFSI. Systems, structures, and programs needed to support the safe storage and transfer of spent fuel such as security, fire protection, and environmental and radiological monitoring will be maintained in accordance with applicable requirements. Equipment maintenance, inspection, and operations will be performed on these systems and structures as appropriate.

During Period 2 the ISFSI capacity will be expanded to accommodate transfer of all spent fuel to dry storage. All spent fuel for Units 1, 2 and 3 will be transferred to the ISFSI and stored there until it is accepted by the Department of Energy (DOE) and transferred to an off-site facility.

The next three periods reflect slightly different ISFSI conditions. Period 3 is concurrent with ongoing site decontamination and dismantlement activities. Period 4 reflects the ISFSI with spent fuel from all three units in dry storage and Period 5 recognizes the potential that Unit 1 fuel may be accepted by the DOE earlier than Units 2 and 3 fuel and ends with DOE acceptance of all Units 2 and 3 fuel.

The SNF D&D Periods (1 and 2) follow DOE acceptance and may be well after License Termination for the balance of the site.

Spent Nuclear Fuel Period 1 – Spent Fuel Transfer Management Transition

- Implementation of Initial Security Enhancements Required for Reductions in Staff
- Design and Fabricate Dry Storage Canisters for Current ISFSI Scope

Spent Nuclear Fuel Period 2 – Spent Fuel Transfer to Dry Storage

- Submit IFMP
- Select Dry Storage System Canister Design and Vendor for Balance of the ISFSI
- Design and Construct ISFSI Expansion
- Purchase, Deliver, and Load Dry Storage Canisters and Storage Models for Balance of the ISFSI
- Complete Transfer of Spent Fuel to ISFSI

Spent Nuclear Fuel Period 3 – Dry Storage during Decommissioning Units 1, 2, and 3 Fuel

Spent Nuclear Fuel Period 4 – Dry Storage Only – Units 1, 2, and 3 Fuel

Spent Nuclear Fuel Period 5 – Dry Storage Only – Units 2 and 3 Fuel

Spent Nuclear Fuel Period D&D 1 – ISFSI License Termination

- Preparation and NRC Review of ISFSI Portion/Revision of License Termination Plan

Spent Nuclear Fuel Period D&D 2 – ISFSI Demolition

- Decontamination of Storage Modules (SFSMs)
- Final Status Survey of ISFSI
- Clean Demolition of HSM's and ISFSI Pad
- Clean Demolition of ISFSI Support Structures
- Restore ISFSI Site
- Preparation of Final Report on ISFSI Decommissioning and NRC Review

C. Detailed Breakdown of Site Restoration Periods

The Site Restoration periods reflect the planning and implementation of dismantlement activities not associated with radioactive materials. The DCE and descriptions below conservatively include activities

from which the SONGS Participants will plan to seek alternatives. These include the complete removal of the intake and discharge conduits in the Pacific Ocean currently required by the California State Lands Commission (CSLC) easement. Previously, the CSLC and SONGS developed an alternative for the SONGS Unit 1 conduits. Another is associated with removal of all subsurface structures that may be required by the US Navy easement. The typical practice has been to remove structures to that depth necessary to remove contaminated materials.

Also included as part of site restoration are severance costs and cost associated with returning the Mesa and other parcels to the U. S. Navy.

Site Restoration Period 1 –Transition to Site Restoration

- Severance Costs Associated with Staffing Reduction in Accordance with State Law
- Other off-site activities are included in the DCE but are not considered part of the Units 2 and 3 PSDAR activities

Site Restoration Period 2 –Building Demolition During Decommissioning

- Demolish South Access for Decommissioning, South Yard Facility
- Other off-site activities are included in the DCE but are not considered part of the Units 2 and 3 PSDAR activities

Site Restoration Period 3 – Subsurface Demolition Engineering and Permitting

- Hydro-geologic Investigation and Outfall Conduit Survey
- Subsurface Structure Removal Analyses for Lease Termination Activities
- Final Site Grading and Shoreline Protection Engineering Planning and Design

Site Restoration Period 4 – Building Demolition to Three Feet Below-Grade

- Demolition Preparations
- De-tension and Remove Containment Building Tendons
- Demolish Diesel Generator Buildings
- Demolish Condensate Buildings and Transformer Pads
- Demolish Full Flow Areas and Turbine Buildings
- Demolish Auxiliary Rad-waste Building
- Demolish Auxiliary Control Building
- Remove Systems and Demolish Make-up Demineralizer Structures
- Demolish Penetration Buildings
- Demolish Safety Equipment and MSIV Buildings
- Demolish Fuel Handling Buildings
- Demolish Containment Buildings
- Demolish Intake and Discharge Structures

Site Restoration Period 5 – Subgrade Structure Removal below Three Feet (if required)

- Install Sheet Piling and Excavation Shoring, Dewatering System, and Effluent Treatment and Discharge Controls

- Demolish and Backfill Subsurface Structures
- Demolish and Backfill Intake Structure Inside Seawall
- Remove Off-shore Intake and Outfall Conduits
- Remove Sheet Piling and Excavation Shoring, and Perform Dewatering and Effluent Treatment
- Finish Grading and Re-vegetate Site As Needed/Required

Site Restoration Period 6 – Final Site Restoration and Easement Termination [details subject to final resolution of negotiations with the U. S. Navy]

- Install Dewatering System and Effluent Treatment and Discharge Controls
- Remove and Stockpile Existing Seawall Erosion Protection
- Remove Seawall and Pedestrian Walkway
- Remove Remaining Intake Structure Beneath Seawall
- Backfill and Compaction of Excavation
- Remove Dewatering System and Effluent Treatment
- Remove Railroad Tracks, Stabilized Slopes, Access Road, and North Parking Lot
- Finish Grading and Re-vegetate Site as Needed/Required

D. General Decommissioning Considerations

1. Major Decommissioning Activities

As defined in 10 CFR 50.2, "Definitions," a "major decommissioning activity" is "any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components for shipment containing greater than Class C waste in accordance with 10 CFR 61.55." The following discussion provides a general summary of the major decommissioning activities currently planned for SONGS Units 2 and 3. These activities may be modified as conditions dictate.

Prior to starting a major decommissioning activity, the plant components will be radiologically surveyed and decontaminated, as required, to minimize worker radiation exposure. Shipping casks and other equipment necessary to conduct decommissioning activities will be designed and procured.

The initial major decommissioning activities will focus on removal, packaging and disposal of piping and components. Following RV and cavity reflood and RV head removal and disposal; the reactor vessel internals will be removed from the reactor vessel and segmented as necessary to separate the GTCC waste which will be placed in storage canisters and modules on the ISFSI designated for that purpose. Using this approach, the internals will be packaged and disposed of independent of the reactor vessel (RV). When the internals segmentation effort is completed, the RV and cavity will be drained and any remaining debris will be removed.

Removal of the reactor vessel follows the removal of the reactor internals. It is likely that the components will be removed by sectioning or segmenting performed remotely. These activities may be

performed in air, rather than underwater, using a control envelope to preclude the spread of contaminated materials.

Additional major decommissioning activities that will be conducted include removal and disposal of the steam generators, pressurizer, spent fuel storage racks, and spent fuel bridge crane. The dismantling of the containment structure will be undertaken as part of the reactor building demolition. As detailed in Section 3 (below) appropriate radiation protection and contamination control measures will be employed to manage these activities.

2. Other Decommissioning Activities

In addition to the major decommissioning activities discussed above, plant components will be removed from the Turbine Building including the turbine generator, condenser, feedwater heaters, moisture separator/reheaters, and miscellaneous system and support equipment. As detailed in Section 3 (below) appropriate radiation protection and contamination control measures will be employed to manage these activities.

3. Decontamination and Dismantlement Activities

The objectives of the decontamination effort are two-fold. The first objective is to reduce radiation levels throughout the facility to minimize personnel radiation exposure during dismantlement. The second objective is to clean as much material as possible to 'unrestricted use' levels, thereby allowing non-radiological demolition and disposal and minimizing the quantities of material that must be disposed of by costly burial as radioactive waste. The second objective will be achieved by decontaminating structural components including steel framing and concrete surfaces. The methods to accomplish this are typically mechanical, requiring the removal of the surface or surface coating and are used regularly in industrial and contaminated sites.

The decontamination and/or dismantlement of contaminated SSCs may be accomplished by: decontamination in place; decontamination and dismantlement; or dismantlement and disposal. A combination of these methods may be utilized to reduce contamination levels, worker radiation exposures, and project costs. Material below the applicable radiological limits may be released for unrestricted disposition (e.g., scrap, recycle, or general disposal). Radioactive contaminated or activated materials will be removed from the site as necessary to allow the site to be released for unrestricted use.

LLRW will be processed in accordance with plant procedures and existing commercial options. Contaminated material will be characterized and segregated for additional onsite decontamination or processing, off-site processing (e.g., disassembly, chemical cleaning, volume reduction, waste treatment), and/or packaged for controlled disposal at a low-level waste disposal facility.

Contaminated concrete and structural steel components will be decontaminated and removed as required to gain access to plant SSCs. After the SSCs are removed and processed as described above,

the remaining contaminated concrete and structural steel components will be decontaminated and/or removed. Contaminated concrete will be packaged and shipped to a low-level waste disposal facility. Contaminated structural steel components may be removed to a processing area for decontamination, volume reduction, and packaging for shipment to processing facility or to a low-level waste disposal facility, as necessary.

Buried and embedded contaminated components (e.g., piping, drains) will be decontaminated in place, or excavated and decontaminated. Appropriate contamination controls will be employed to minimize the spread of contamination and to protect personnel.

4. Radioactive Waste Management

A major component of the total cost of decommissioning SONGS Units 2 and 3 is the cost of safely packaging and disposing of contaminated SSCs, contaminated soil, resins, water, and other plant process liquids. A waste management plan will be developed consistent with regulatory requirements for each waste type. Currently, LLRW Classes B and C may be disposed of at the Waste Control Services (WCS) waste disposal site in Andrews County, Texas. The waste management plan will be based on the evaluation of available methods and strategies for processing, packaging, and transporting radioactive waste in conjunction with the available disposal facility and associated waste acceptance criteria.

Class A LLRW will be disposed at a licensed disposal site. (SONGS has contracted with Energy*Solutions* to use the facility located in Clive, Utah as well as WCS). If other licensed Class B and C LLRW facilities become available in the future, SONGS may choose to use them as well.

5. Removal of Mixed Wastes

Mixed wastes (hazardous and radioactive) generated during decommissioning, if any, will be managed in accordance with applicable Federal and State regulations. If technology, resources, and approved processes are available, the processes will be evaluated to render the mixed waste non-hazardous. Otherwise, mixed wastes from SONGS will be transported by authorized and licensed transporters and shipped to authorized and licensed facilities.

6. Site Characterization

During the decommissioning process, a site characterization will be performed in which radiological, regulated, and hazardous wastes will be identified, categorized, and quantified. Surveys will be conducted to establish the contamination and radiation levels throughout the plant. The information will be used in developing procedures to ensure the contaminated areas are removed and ensure that worker exposure is controlled. Surveys of the selected outdoor areas will also be performed including surveys of soil and groundwater near the site. As decontamination and dismantlement work proceeds, surveys will be conducted to maintain the site characterization current and ensure that decommissioning activities are adjusted accordingly.

7. Groundwater Protection

A groundwater protection program was initiated at SONGS in accordance with NEI 07-07, "Industry Groundwater Protection Initiative, Final Guidance Document," in August 2007 (Reference 11). A site hydrology study was initially completed as part of this initiative and was updated in 2012. Monitoring wells were installed around the plant to monitor for radionuclides. Acceptable levels of contaminants, as defined by the program, have been observed throughout the sampling program implemented as part of this initiative. Appropriate program elements will be maintained during decommissioning.

8. Change to Management and Staffing

With the plant shut down and defueled, plant management and staffing levels have been and continue to be adjusted to reflect the transition from an operating plant to a plant in decommissioning status. Staffing plans are addressed in the DCE.

III. ESTIMATE OF EXPECTED DECOMMISSIONING AND SPENT FUEL MANAGEMENT COSTS

10 CFR 50.82(a)(8)(iii) requires that a site-specific decommissioning cost estimate be prepared, and submitted within two years following permanent cessation of operations. 10 CFR 50.82 (a)(4)(i) requires that the PSDAR contain a site-specific decommissioning cost estimate including the projected costs of managing irradiated fuel.

Energy*Solutions* has prepared a site-specific DCE for SONGS, which also provides projected costs of managing irradiated fuel, as well as non-radiological decommissioning and other site restoration costs,. The site-specific decommissioning cost analysis is being submitted concurrent with the IFMP and this PSDAR and fulfills the requirements of 10 CFR 50.82(a)(4)(i) and 10 CFR 50.82(a)(8)(iii). A summary of the annual costs associated with decommissioning, irradiated fuel management and site restoration are provided in the Irradiated Fuel Management Plan also being concurrently submitted in accordance with 10 CFR 50.54(bb).

The methodology used by Energy*Solutions* to develop the site-specific decommissioning cost analysis follows the approach originally developed by the Atomic Industrial Forum (now Nuclear Energy Institute) in their program to develop a standardized model for decommissioning cost estimates. The results of this program were published as AIF/NESP-036, "A Guideline for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," (Reference 7). This document includes a unit cost factor method for estimating direct activity costs, simplifying the estimating process. The unit cost factors used in the study reflect the latest available data at the time of the study concerning worker productivity during decommissioning.

The decommissioning of the SONGS site will be funded from Nuclear Decommissioning Trusts established by each SONGS Participant for each unit. The relative liabilities of each SONGS Participant are detailed in the DCE. Sufficient funds (based on balances and earnings) are projected to be available to complete the planned decommissioning activities.

As discussed in Section IV of the IFMP the CPUC will establish processes for oversight of withdrawals from the nuclear decommissioning trusts by SCE and SDG&E, and designate the specific amounts from the existing fund balances that are available for the three decommissioning cost categories: (1) spent fuel management; (2) site restoration; and (3) license termination. As entities not subject to CPUC jurisdiction, Anaheim and Riverside are not required to obtain CPUC authorization with respect to withdrawals from their respective Nuclear Decommissioning Trusts.

IV. ENVIRONMENTAL IMPACTS

As shown in this section, SCE has evaluated the environmental impacts of decommissioning SONGS Units 2 and 3 to determine if anticipated impacts are bounded by existing environmental impact statements, the NRC's generic decommissioning EIS (GEIS, Reference 6) and the SONGS Final Environmental Statement (FES, Reference 8). As noted in Regulatory Guide 1.185, C.4 "the PSDAR does not need to include the analysis of the specific environmental impacts associated with decommissioning activities....the licensee must ensure that supporting documentation and analyses are available at the reactor site for inspection by the NRC Staff." Such detailed documentation and analyses are contained in the Environmental Impact Evaluation (EIE) and its supporting references as noted in the Developmental References. They are available on-site for NRC review as well as on the SONGScommunity.com website and are summarized below. Both the detailed documentation and analyses and the following summary were reviewed by internal and external subject matter experts, independent third-party reviewers and the Community Engagement Panel discussed in the Introduction to this report.

In the GEIS, the NRC reviewed the environmental impacts resulting from decommissioning on a generic basis, and identified a need for site-specific analyses for: (1) threatened and endangered species and (2) environmental justice. In addition, site-specific analyses are called for whenever decommissioning plans indicate that activities will impact areas beyond the operational portions of a facility. The SONGS FES addresses decommissioning, but does not establish bounding environmental impacts specific to decommissioning. However, the FES' discussion of impacts for construction does describe bounding impacts as it related to potential dewatering during decommissioning.

The NRC, in its GEIS, identified additional activities that are performed in conjunction with decommissioning. These activities are regulated by the NRC but any associated environmental impacts are addressed directly in conjunction with those regulated activities. These activities include those related to the decision to permanently cease operations, irradiated fuel management in wet or dry storage, irradiated fuel transport and disposal, and the treatment, and/or disposal of LLRW. SCE similarly excluded consideration of such activities to remain consistent with the NRC's approach.

A. Environmental Impacts of Decommissioning SONGS

SCE assessed the potential for environmental impacts to each resource area from decommissioning activities using the evaluations in the GEIS as a guide. Like the GEIS, the analysis assumed that operational mitigation measures will be continued and did not rely on the implementation of new

mitigation measures unless specified. Releases to the environment, waste volumes, and other environmental interfaces were estimated in the DCE or other sources referenced in the EIE. This information was then assessed against the potential for impact and the existing environmental conditions at SONGS to identify impacts and determine whether the GEIS and FES remain bounding. The GEIS categorizes significance levels as SMALL (impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource or do not exceed permissible levels in the NRC's regulations), MODERATE (impacts are sufficient to alter noticeably, but not to destabilize, important attributes of the resource), or LARGE (impacts are clearly noticeable, and are sufficient to destabilize important attributes of the resource).

To support the evaluation, SCE established the baseline environmental and societal conditions through site-specific information as well as vicinity and regional data available from local, state, and federal agencies. In addition, the evaluation considered the existing permit conditions and limitations for water and air permits and NRC regulatory requirements, including those focused on occupational dose, public dose, radiological effluents, and LLRW shipping. Federal, state, and local requirements for non-radiological interfaces with the environment were considered. These include regulatory limits on water withdrawal and discharges, air emissions including fugitive dust, noise levels, and protection of avian, terrestrial and aquatic species, protection of cultural resources, disposal of non-radiological waste, and worker health protection.

SCE reviewed the planned decommissioning activities for SONGS Units 2 and 3 and compared these to the decommissioning activities that NRC evaluated in the GEIS. The planned activities fall within the activities that NRC evaluated. While each decommissioning site is unique, no unusual site-specific features or aspects of the planned SONGS Units 2 and 3 decommissioning have been identified. Furthermore, the practices used to accomplish the individual decommissioning tasks will employ conventional methods.

SCE's review confirmed that the anticipated or potential impacts are within the bounds of the generic impacts that the NRC described in the GEIS. There are no applicable bounding impacts for threatened and endangered species and environmental justice. The site-specific analyses determined that the planned SONGS Units 2 and 3 decommissioning activities are not likely to result in significant impacts to threatened and endangered species nor have disproportionate impacts on minority or low-income populations. The following discussions summarize the full Environmental Impact Evaluation focusing on the reasons for reaching this conclusion.

1. Onsite/Offsite Land Use

SCE's decommissioning plans include building demolition and removal within the 84-acre easement hosting the SONGS Units 2 and 3 reactor units and infrastructure. SCE plans to seek an easement lease amendment from the CSLC for the partial removal or abandonment in-place of the SONGS Units 2 and 3 intake and discharge conduits. In addition, the existing rail spur serving the site will most likely be used in support of waste shipments.

The SONGS site is currently used for utility-related industrial land uses, with the majority of the property within the easement having been previously disturbed during construction and operation of the plant. The coastal bluff areas located in the northwest and southeast portions of the 84-acre easement have remained undeveloped in compliance with the California Coastal Commission (CCC) Guarantee Agreement, in which SCE provided assurance that they will be protected and that they will remain in their natural state. It is anticipated that there will be no changes in onsite land use patterns during decommissioning.

The GEIS assessment for land use concluded that the impact would be SMALL for sites that did not require additional land for decommissioning activities. If additional land was needed the impact should be determined on a site-specific basis. Because no additional lands are needed SONGS onsite land use impacts during decommissioning are bounded by the GEIS and are categorized as SMALL.

2. Water Use

SONGS Units 2 and 3 acquires potable water through the South Coast Water District, a member agency of the Municipal Water District of Orange County (MWDOC). The site historically used water from the Pacific Ocean for its condenser cooling and service water cooling functions. The operational demand for cooling and makeup water has been significantly reduced since SONGS Units 2 and 3 permanently ceased operation. Condenser cooling is not required when the plant is not operating and service water cooling demands have been reduced to the extent possible (primarily spent fuel pool cooling). The normal operation demand was previously over 830,000 gpm per unit and is currently approximately 34,000 gpm total for both Units 2 and 3. During the decommissioning period, SONGS intends to continue to reduce cooling water demands with the intent to eliminate such demands on the Pacific Ocean as soon as possible.

The GEIS assessment of water use concluded the impact on water use would be SMALL if the decommissioning did not significantly increase water use. Water uses for decommissioning include staff usage, fuel storage (replacement of evaporative losses, etc.), fuel transfer (washing down transport casks), large component segmentation generally performed underwater, decontamination and dismantlement (if water-jet or similar techniques are employed). Water uses are anticipated to be significantly less than during operation. Thus water use impacts during decommissioning are bounded by the GEIS.

3. Water Quality – Non-Radiological

Major activities that could impact surface and groundwater quality during decommissioning include site excavation, stabilization, decontamination, dismantlement, and dewatering. These activities present the potential of spills, migration of low concentrations of radioactivity or hazardous substances not previously identified, and leaching from subsurface structures.

As discussed in Section 2 above, the site uses water from the Pacific Ocean for its condenser cooling and service water cooling functions. Water used for cooling functions is discharged through the ocean outfalls for Units 2 and 3, and is currently regulated under individual National Pollutant Discharge Elimination System (NPDES) Permits from the San Diego Regional Water Quality Control Board (SDRWQCB). The individual unit permits may be merged into a single NPDES Permit which would also continue to address groundwater dewatering discharges, and multiple minor waste stream discharges from within SONGS Units 2 and 3.

Storm water discharge is regulated and controlled through an industrial storm water general permit issued by the SDRWQCB. This permit requires SONGS to develop, maintain, and implement a storm water pollution prevention plan (SWPPP) for the facility. Storm water-related monitoring plans and reporting protocols will be updated as necessary to address permit requirements and decommissioning activities.

A previous SCE study concluded that no drinking water pathway exists for exposure from SONGS operations. Furthermore, the nearest drinking water well is more than one mile inland. Previous studies indicate that even under extreme pumping conditions, a seaward gradient will exist. Therefore, any dewatering is not expected to result in saltwater intrusion.

The GEIS assessment of water quality impacts concluded the impacts would be SMALL based on compliance with regulatory requirements including the appropriate application of best management practices (BMPs) and controls. SCE will follow standard storm water BMPs as documented in the current Industrial SWPPP and implement the current SPCC plan to minimize the chance of both groundwater and surface water contamination. In the event an unknown area of hazardous substances is identified during sub-grade soil excavation and structures removal, the area will be assessed and controlled. Due to the implementation of BMPs and compliance with permits, the potential impacts of decommissioning on nonradioactive aspects of water quality for both surface water and groundwater are bounded by those addressed in the GEIS.

4. Air Quality

Emission sources in San Diego County are primarily mobile sources (vehicular traffic) and ambient air quality standards are frequently exceeded for ozone and particulate matter due to routine vehicular traffic. Relatively minor stationary sources, such as those planned for use at SONGS, are projected to be a fraction of the average daily emissions permitted by the San Diego Air Pollution Control District (SDAPCD).

The most likely impact of decommissioning on air quality will be due to dust. SCE will employ standard dust control measures during decommissioning in accordance with SDAPCD dust abatement and visible emissions requirements. Air emissions due to commuting workers will actually be less since the work force during all phases of decommissioning is expected to be smaller than the peak number of workers used for construction or refueling outages.

The NRC's GEIS generically determined air quality impacts associated with decommissioning to be SMALL due to the sufficiency of current and commonly used control and mitigation measures. SCE will implement standard mitigation measures to reduce emissions during decommissioning per the requirements of the SDAPCD. Therefore, air quality impacts related to decommissioning of SONGS Units 2 and 3 are bounded by the GEIS.

5. Aquatic Ecology

SCE has characterized the aquatic environment in the vicinity of the SONGS Units 2 and 3 intake and discharge conduits prior to construction of and during the operation of SONGS. There are a variety of habitat types surrounding the SONGS Units 2 and 3 conduits. The marine habitat offshore of SONGS consists of a mixture of sand, cobble, and isolated areas of exposed rock. The area of high marine productivity in the immediate vicinity of the plant site is the shallow sub-tidal zone, approximately 1,300 feet north of SONGS. This area supports a biological community dominated by surfgrass, and feather boa kelp. The San Onofre kelp bed is approximately 650 feet south of SONGS Unit 2 diffusers in a water depth of 40 to 50 feet. The benthic fish community is generally dominated by queenfish; northern anchovy; white croaker and speckled sanddab.

Since ceasing permanent operations at SONGS Units 2 and 3, SCE has reduced ocean water withdrawals and discharge by approximately 96 percent from normal operating flows. The remaining flow is primarily associated with cooling spent fuel while in wet storage. As noted earlier, spent fuel storage and cooling are existing operational activities and is not re-addressed as part of this environmental review. SONGS will continue to comply with its applicable regulatory and permit requirements associated with reduction of impingement and entrainment impacts due to water withdrawals.

SCE sought and obtained an amendment to the CSLC easement lease for Unit 1 which allowed the intake and discharge conduits to remain buried beneath the seafloor. SCE is planning to pursue similar amendments for SONGS Units 2 and 3. If the CSLC approves the amendment to allow SCE to abandon the conduits in place, the environmental impacts are projected to be SMALL with the application of appropriate mitigation measures enumerated in the lease amendment. Complete removal of the conduits, as is currently required by the CSLC lease, is anticipated to have significant adverse environmental impacts. The detailed Environmental Impact Evaluation assumes the CSLC lease is amended. If the CSLC lease is not amended, the environmental impacts from complete removal of the conduits will have to be further addressed. If necessary, SCE will update the PSDAR and initiate other regulatory interactions to address the results of this analysis.

There are no surface water bodies on the SONGS site, but the Pacific Ocean borders the site and vernal pools are found northwest of SONGS Parking Lot 4. Decommissioning activities for SONGS Units 2 and 3 will include the application of common BMPs, compliance with the SONGS storm water permit, and implementation of the storm water pollution prevention plan, which will be updated as necessary to address decommissioning activities. These measures will ensure that any changes in surface water quality will be non-detectable and non-destabilizing.

The NRC determined aquatic ecology impacts to be SMALL when only aquatic resources within a plant's operational areas are disturbed. The potential impacts to aquatic ecology are bounded by the GEIS and no additional mitigation measures beyond those anticipated as conditions of the CSLC easement lease amendment are likely to be warranted.

6. Terrestrial Ecology

The SONGS site is almost entirely paved and developed. However, there are small strips of intact scrub-shrub habitat and ornamental vegetation surrounding the parking lots and between developed areas of the plant. The SONGS site also has undeveloped coastal bluffs that are explicitly protected from development under the CCC Guarantee Agreement. The onsite coastal bluff in the northwest area of SONGS is sparsely vegetated, California desert-thorn scrub habitat. The larger onsite coastal bluff in the southeast area of SONGS is approximately 5 acres and is dominated by California sagebrush scrub vegetation. This bluff is contiguous with the San Onofre bluffs of the San Onofre State Beach, which supports two native vegetation associations (Diegan coastal sage scrub and southern foredune) and small areas of disturbed coastal sage scrub habitat. The coastal bluff areas provide opportunity to support wildlife; however, the light, noise, and frequent human presence due to the proximity of SONGS and the state beach result in a more disturbed habitat than will otherwise be optimal for many species. Avian species are highly mobile and not subject to barriers such as roads and developed areas and may utilize scrub habitat or open surfaces for nesting and temporary perching.

The decommissioning activities will include noise and dust from dismantlement of facilities and heavy equipment traffic, surface runoff, emissions from construction equipment, and the potential for bird interactions with crane booms or other construction equipment. These activities will be conducted in compliance with air quality and noise regulations, and SCE will use avoidance and minimization measures to address potential impacts. Compliance with applicable regulations, air permits, noise restrictions along with the temporary nature of the various decommissioning tasks (e.g., use of cranes) will minimize the impacts to terrestrial species as well as the human community. Decommissioning plans do not currently include the use of explosives, which could disturb terrestrial resources. Should those plans change the environmental impacts will be reevaluated.

SONGS is located within the coastal zone and prior to active dismantlement, SCE will file a coastal development permit application with the CCC. As part of this permitting process, decommissioning activities within the coastal sage habitat areas, coastal bluff, and beach areas will be reviewed by the CCC and United States Fish and Wildlife Service (USFWS) for potential environmental impacts including

the federally listed coastal California gnatcatcher and other protected species and species of concern. Any necessary mitigation measures will be included as conditions of the CCC permit. The removal of various current SONGS features along the perimeter of the developed plant adjacent to and within the natural area could potentially require ground disturbance in unpaved areas. Appropriate avoidance and minimization measures will be used to minimize the impact of any ground disturbance.

With the implementation of appropriate avoidance and minimization measures and compliance with permit conditions as discussed above, decommissioning of SONGS Units 2 and 3 is not anticipated to adversely impact any terrestrial resources and the impacts will be bounded by the GEIS which determined them to be SMALL.

7. Threatened and Endangered Species

Seventeen federally or state protected species utilize habitat within the vicinity (a 6-mile radius) of the SONGS site. These species are listed in Table IV-1, along with their protection status and critical habitat designation. Other species of concern are also addressed in the detailed Environmental Impact Evaluation including both the critically imperiled and imperiled species listed in the California Natural Diversity Data Base and located within one mile of the site but are not otherwise addressed here.

The list includes four federally listed marine turtles. However, none is considered a full-time resident in the vicinity of SONGS and they only migrate through the vicinity. Another federally listed marine reptile, the Hawksbill turtle, sporadically nests in the southern part of the Baja peninsula and foraging sub-adults and juveniles have been sighted along the California coast. Given the SMALL impacts on water use and water quality during decommissioning and the ability of these species to migrate away from the site, these species should not be adversely impacted by decommissioning.

The decommissioning activities will indirectly impact protected species through dust generation from structure demolition, noise from dismantlement of facilities and heavy equipment traffic, surface runoff, emissions from construction equipment, and potential bird interactions with crane booms or other construction equipment. The decommissioning activities will be conducted in compliance with air quality and noise regulations and SCE will use appropriate avoidance and minimization measures. Compliance with applicable regulations, air permits, and noise restrictions related to daylight working along with the temporary nature of the various decommissioning tasks will minimize any such impacts. Decommissioning plans do not currently include the use of explosives, which could disturb protected species. These measures will minimize impacts to protected terrestrial species that inhabit or visit the SONGS site.

Although rare on the site, there has historically been one protected plant species in the vicinity of SONGS, the thread-leaved brodiaea. Decommissioning activities will generally be confined to previously disturbed areas (e.g., paved, high traffic areas). Otherwise, the SCE environmental staff will conduct an environmental assessment per established procedures. The procedure requires an assessment prior to any land disturbance, soil addition, digging, grading, or trenching outside the paved and concreted areas; maintenance activities near surface water, and wetlands and trimming or removal of native plants

other than landscape maintenance. Therefore, adverse impacts on protected plant species are not anticipated.

Decommissioning of SONGS Units 2 and 3 is not anticipated to adversely impact any federally or state-listed species. As discussed above, decommissioning activities will generally be limited to previously disturbed areas on-site, near-shore and off-shore. SCE will employ mitigation measures as required by the regulatory agencies to minimize impacts to the environment and protect listed species. In addition, SCE will implement BMPs and conduct assessments as called for in its environmental protection procedure(s), as well as comply with permit and regulatory requirements to minimize indirect impacts from noise, air emission, dust, and runoff. Therefore, impacts to threatened or endangered species from decommissioning are expected to be SMALL.

Table IV-1

Threatened and Endangered Species Identified within the Vicinity of SONGS

Scientific Name	Common Name	State Status[a]	Federal Status[b]	Critical Habitat within Vicinity
AMPHIBIAN SPECIES				
Anaxyrus californicus	Arroyo toad	—	FE	yes[c]
AVIAN SPECIES				
Charadrius alexandrinus nivosus	Western snowy plover	—	FT	yes[c]
Empidonax traillii extimus	Southwestern willow flycatcher	SE	FE	No
Haliaeetus leucocephalus	Bald eagle	SE	delisted	No
Polioptilacalifornica californica	Coastal California gnatcatcher	—	FT	yes[c]
Vireo bellii pusillus	Least Bell's vireo	SE	FE	yes[c]
FISH SPECIES				
Orcorhynchus mykiss	Steelhead trout	—	FE	yes[c]
INVERTEBRATE SPECIES				
Branchinecta sandiegoensis	San Diego fairy shrimp	—	FE	yes[c]
Streptocephalus woottoni	Riverside fairy shrimp	—	FE	No
MAMMALIAN SPECIES				

Scientific Name	Common Name	State Status[a]	Federal Status[b]	Critical Habitat within Vicinity
Dipodomys stephensi	Stephen's kangaroo rat	ST	FE	No
Perognathus longimembris pacificus	Pacific pocket mouse	—	FE	No
PLANT SPECIES				
Brodiaea filifolia	Thread-leafed brodiaea	SE	FT	yes[c]
REPTILIAN SPECIES				
Caretta caretta	Loggerhead sea turtle	—	FE	No
Chelonia mydas	Green sea turtle	—	FT	No
Dermochelys coriacea	Leatherback sea turtle	—	FE	No
Lepidochelys olivacea	Olive Ridley's turtle	—	FT	No

a. SE = state endangered; ST = state threatened;
b. FE = federally endangered; FT = federally threatened
c. The USFWS has critical habitat delineated within the SONGS site vicinity. However, the designation explicitly excludes Camp Pendleton and thus the SONGS site. Further, the term vicinity includes any area within a 6 mile radius of the site and is not limited to the site itself.

8. Radiological

Decommissioning activities have the potential to contribute to radiological impacts. SONGS Units 2 and 3 may continue to have limited gaseous and liquid radiological effluents until most of the decommissioning activities are complete and the irradiated fuel is transferred to dry storage. SCE is evaluating options to significantly reduce, if not eliminate, routine liquid effluents through the use of self-contained clean-up systems for ongoing systems and activities.

Occupational Dose
The GEIS estimates for the reference pressurized water reactor (PWR) dose is 1,215 person-rem for DECON. In the most recent supplement to the GEIS, the NRC reviewed data available from decommissioning experience subsequent to their initial review (in 1988). Because the range of cumulative occupational doses reported by reactors undergoing decommissioning was similar to the range of estimates for reference plants presented in the 1988 revision of the GEIS, the NRC did not update its estimates for occupational dose.

SCE expects the SONGS dose to be bounded by the referenced PWR dose since: a number of major components which often contribute to area dose rates are relatively new (steam generators and reactor vessel head); and, as a result of SONGS operational dose reduction efforts (i.e., zinc injection). A more detailed estimate will be developed to support evaluation of decontamination scope.

The regulatory standard for worker exposure is a dose limit per worker rather than a cumulative dose. Detailed occupational dose estimates will be performed as part of the work planning process. Such planning will address means to reduce occupational dose where appropriate. SCE remains committed to keeping dose to plant personnel 'As Low as Reasonably Achievable' (ALARA). The activities that have potential radiological impacts will be conducted in a manner to keep doses ALARA and well within regulatory limits.

Public Dose
The NRC generically concluded that reactors undergoing decommissioning could reasonably be expected to have emissions and public doses comparable to or substantially less than the levels experienced during normal operation of those facilities. The Radiological Environmental Monitoring Program (REMP) results demonstrate that the radiological environmental impact of the operation of SONGS Units 2 and 3, and the resulting dose to a member of the general public, is negligible.

SCE will continue to monitor effluents, comply with all applicable regulatory limits, and continue its REMP to assess the impacts to the environment from these effluents.

In summary, SCE estimates that SONGS Units 2 and 3 decommissioning activities will result in occupational and public doses within NRC estimates. Therefore, SONGS' radiological impacts during decommissioning are bounded by the GEIS which determined the radiological impacts to be SMALL.

9. Radiological Accidents

Many activities that occur during decommissioning are similar to activities that commonly take place during maintenance outages at operating plants such as decontamination and equipment removal. Accidents that could occur during these activities may result in injury and local contamination. However, they are not likely to result in contamination off-site.

The limiting design basis accidents (DBAs) applicable to a decommissioning plant are those involving the spent fuel pool. All DBAs and severe accidents involving the reactor are precluded as a result of transfer of spent fuel from the reactor vessels to the pools and ultimately the ISFSI. The environmental impacts of DBAs, including those associated with the spent fuel pool, were evaluated during the initial licensing process and documented in the FES. Furthermore, the impacts of these events are less than previously evaluated due to the time since the fuel was most recently irradiated.

The NRC's GEIS analysis relies in part on the waste confidence rule regarding spent nuclear fuel related severe accidents. The waste confidence GEIS (Reference 9) continues to consider severe accidents involving the spent fuel pool to be a SMALL risk.

Thus, SONGS' radiological accident impacts during decommissioning are bounded by NRC's Decommissioning GEIS which determined such risks to be SMALL.

10. Occupational Issues

SONGS currently has an industrial safety program and safety personnel to promote safe work practices and respond to occupational injuries and illnesses. Equivalent safety programs will continue to be in effect during decommissioning activities.

SONGS has an average occupational injury rate well below that of the heavy construction industry sector and consistent with the power generation and nuclear power industry. Decommissioning activities will be conducted in a manner reflecting personnel safety as a critical element. Therefore, SONGS occupational safety impacts are considered to be bounded by the GEIS which generically determined occupational safety impacts to be SMALL.

11. Cost

Decommissioning costs for SONGS are discussed in the DCE being submitted concurrently.

12. Socioeconomics

The primary socioeconomic impacts of decommissioning are related to staffing changes and decreasing tax revenues. Impacts related to the decision to permanently cease operations are outside the scope of this evaluation. SCE determined the staff reduction impacts from the decision to be minimal. The staff reductions represent 0.04 percent and 0.03 percent of San Diego County's and Orange County's workforces, respectively. Any impacts will be deferred somewhat due to the employment of temporary staff necessary to accomplish the various decommissioning activities.

Similarly, SONGS is located in San Diego County and its property assessment is a relatively small portion of San Diego County's total tax collections. Historically, SONGS' contribution to the county property tax collections has been consistently less than 1 percent. SONGS' tax obligations will be reduced due to decommissioning, but SCE and SONGS will continue to contribute to county tax revenues.

It is anticipated that there will be limited or no changes or impacts to the local community and socioeconomic conditions and less impact than would be expected generically where other nuclear facilities have a higher relative impact on the job market or tax base. Thus, SONGS' impacts are bounded by those considered in the GEIS in which the NRC generically determined socioeconomic impacts to be SMALL.

13. Environmental Justice

Decommissioning activities that may potentially affect identified minority and low-income populations include those related to staffing changes and offsite transportation. However, the assessment of environmental justice also considered other specific issues (e.g., water use, air quality). SCE has determined that no significant offsite impacts will be created by SONGS 2 & 3 decommissioning activities. As generic NRC guidance recognizes, if no significant offsite impacts occur in connection with the proposed action, then no member of the public will be substantially affected. Therefore, there can

be no disproportionately high and adverse impacts on members of the public, including minority and low-income populations. In addition, staffing is not anticipated to be an impact due to the large population and robust job market in the area (see Section 12 above).

The environmental justice evaluations utilize a 50-mile radius around the plant as the potentially impacted area. To complete this evaluation, the 2006–2010 low-income data and 2010 minority population data for California were obtained from the United States Census Bureau (USCB) and processed using ESRI ArcGIS 10.1 software. All census data were downloaded in USCB block group level geography so that the environmental justice evaluations were consistent between the minority and low-income analyses. The evaluations and results are detailed in the EIE which concluded there were no disproportionate impacts.

In its GEIS, the NRC concluded that adverse environmental justice impacts and associated significance of the impacts must be determined on a site-specific basis. Unlike many nuclear sites, SONGS is located in and near relatively large communities with significant other commercial and industrial activities. Thus, the impact of SONGS shutdown is less severe than may otherwise be the case. Further, SCE has determined that no significant offsite environmental impacts will be created by SONGS Units 2 and 3 decommissioning activities. Since no significant offsite impacts occur in connection with the proposed action, no member of the public will be substantially affected. Therefore, it is unlikely for there to be a disproportionately high and adverse impact or effects on specific groups or members of the public, including minority and low-income populations, resulting from the decommissioning of SONGS Units 2 and 3.

14. Cultural Historic and Archeological Resources

No prehistoric or historic archaeological sites or historic sites eligible for listing or listed on the National Register of Historic Places, California Register of Historical Resources, or San Diego County Local Register of Historical Resources are located within the SONGS site lease easement and no traditional cultural properties are known to be present. Two prehistoric archaeological sites and three historic archaeological sites were identified within 0.5 miles of SONGS Units 2 and 3.

All of these areas are outside the operational/decommissioning site. In its GEIS, the NRC concluded that for plants where the disturbance of lands beyond the operational areas is not anticipated, the impacts on cultural, historic, and archeological resources will be SMALL. Since decommissioning activities are confined to the SONGS site, no adverse impacts are anticipated. SONGS' impacts on cultural, historical, and archeological resources during decommissioning fall well within the bounds established by the NRC in the GEIS.

15. Aesthetic Issues

In its GEIS, the NRC stated that removal of structures is generally considered to be a beneficial aesthetic impact and drew the generic conclusion that for all plants, the potential impacts from decommissioning on aesthetics are SMALL and that any mitigation measures are not likely to be beneficial enough to be

warranted. Similarly, the aesthetic impact of final result of decommissioning SONGS Units 2 and 3 will be less than that of the current aesthetic impact of the plant. During dismantlement, any adverse visual intrusion will be temporary and will ultimately serve to reduce the aesthetic impact of the site. Therefore, the impacts of SONGS on aesthetic resources during decommissioning are bounded by the GEIS.

16. Noise

Offsite noise sources that affect the ambient noise environment in the vicinity of SONGS include Interstate-5, the San Diego Northern Railroad, and military operations. During the decommissioning process, the sounds that might be heard at offsite locations include noise from construction vehicles and tools. The timing of noise impacts and the duration or intensity will vary. The nearest sensitive receptors to SONGS are recreational users of San Onofre State Beach where the ambient noise environment can exceed 70 dBA. The more intense decommissioning activities will occur 400 ft or more from the beach access public walkway in front of the SONGS sea wall.

Due to the relatively high ambient noise levels surrounding SONGS, decommissioning activities are not expected to produce noise levels that could impact the activities of humans or threatened and endangered species. In addition, SCE will comply with the local noise regulations for construction sites, which restrict the average sound level at the property boundary to 75 dBA between 7 a.m. and 7 p.m., and any additional agency permit requirements including any lower allowed limits during evenings and overnight. Therefore, noise impacts during decommissioning of SONGS Units 2 and 3 are bounded by the previously issued GEIS, which generically determined the noise impacts associated with decommissioning to be SMALL.

17. Transportation

Transportation impacts are dependent on the number of shipments to and from the facility, the type of shipments, the distance that material is shipped, and the number of workers commuting to and from the site.

Transportation infrastructure within the vicinity of SONGS includes one major north- and south-bound freeway, I-5, an assortment of local and county roads, passenger and cargo rail service (part of the Los Angeles–San Diego corridor), and an existing rail spur serving the SONGS site. The 2011 average annual daily traffic (AADT) count for this portion of I-5 was 132,000 vehicles.

SCE compared the assumptions and analysis inputs used for NRC's analysis with waste volumes estimated for SONGS Units 2 and 3 decommissioning, transport mode, and disposal facility options. Due to the availability of the rail line, a substantial portion of the shipments will likely use that mode of transportation. The NRC indicates use of rail reduces radiological impacts by more than a factor of 10 over truck shipments. Furthermore, disposal facilities available for SONGS Units 2 and 3 radiological wastes are less than half the distance assumed by NRC in its analysis. Therefore the generic impacts bound those associated with SONGS Units 2 and 3.

Furthermore, SCE will comply with all applicable NRC and U.S. Department of Transportation (DOT) regulations, including Federal Railroad Administration regulations and requirements, and will use approved packaging and shipping containers for waste shipment. SCE will also comply with State of California regulations enforced by Caltrans and the California Highway Patrol. The NRC has generically concluded that the radiological impacts of transporting radiological waste from decommissioning will be SMALL and those for SONGS Units 2 and 3 are bounded by the GEIS.

SCE estimated a peak of approximately 560 workers during decommissioning and the vehicular traffic due to commuting will likely exceed the 200 per peak hour threshold, prompting review for potential to impact traffic congestion as required under the local congestion management plan. SCE estimated peak truck traffic due to waste shipments to be approximately 150 per day. The decommissioning traffic associated with SONGS is considered negligible compared to existing traffic volumes and will not be expected to significantly alter congestion on roadways. In addition, this amount of traffic is not expected to significantly deteriorate roadways; therefore the GEIS is bounding and the non-radiological transportation impacts of decommissioning are SMALL.

Offshore activities to remove vertical risers on the intake and discharge conduits will increase marine vessel traffic in the area. It is expected that these activities will not cause either a navigational safety hazard or a substantial delay in the normal movements of commercial or recreational vessels. The environmental impacts review for the Unit 1 conduit disposition indicated that impacts to recreational and commercial transportation will be insignificant.

18. Irreversible and Irretrievable Commitment of Resources

SONGS Units 2 and 3 decommissioning will involve dismantlement and removal of structures and restoration of the property to a state for unrestricted release per NRC regulations in accordance with the criteria for license termination in 10 CFR 20, Subpart E. Furthermore, the property will be returned to the U.S. Navy under negotiated terms of the easement. The activities necessary to decommission SONGS Units 2 and 3 involve a minor irretrievable commitment of consumable materials (including materials for decontamination, solvents, industrial gases, tools, fuel, etc.). The irreversible commitment of such resources is not unique and is bounded by those considered by the NRC in the GEIS which concluded consumption to be minor.

Waste from decommissioning of SONGS Units 2 and 3 will consume space at waste facilities. California has multiple facilities permitted for the storage, treatment, and disposal of hazardous and universal waste. The nonradioactive waste is assumed to be shipped to an out-of-state landfill due to the moratorium on disposal of decommissioned materials at California nonhazardous landfills. The decommissioning of SONGS Units 2 and 3 will result in minor irretrievable or irreversible commitment of resources bounded by the GEIS in which the NRC determined will be SMALL impacts.

B. Environmental Impacts of License Termination – NUREG-1496

The License Termination Plan (LTP) has not yet been developed. As noted earlier, it is required to be submitted at least two years prior to the proposed termination date. In general, the LTP outlines the basis for an administrative/legal activity. No physical work beyond that already addressed is anticipated. Thus, there are no environmental impacts beyond those already addressed that need to be addressed at this point in the process.

C. Discussion of Decommissioning in the FES

Applicable portions of the FES were addressed as noted in each of the topics previously summarized.

D. Additional Considerations

SCE has not identified any unique considerations that need to be further addressed. The previous topic summaries address a sufficiently wide range of issues.

E. Conclusion

SCE has performed an environmental review to evaluate environmental impacts associated with decommissioning activities, confirming that the anticipated or potential impacts are within the bounds of the generic impacts that NRC described in the GEIS. Further, while there are no applicable bounding impacts for threatened and endangered species and environmental justice discussed in the GEIS, the SONGS Units 2 and 3 decommissioning activities are not anticipated to result in significant impacts to threatened and endangered species or disproportionate impacts on minority or low-income populations. This is principally due to the following:

- Planned activities fall within the activities that the NRC evaluated. There are no unique aspects of the plant or decommissioning techniques that will invalidate previously drawn conclusions.
- Methods to be employed to dismantle and decontaminate the site are standard construction-based techniques fully considered in the GEIS.
- SCE will continue to comply with NRC dose limits and conduct activities in accordance with ALARA principles.
- SCE will continue to comply with the SONGS Offsite Dose Calculation Manual, Radiological Effluent Monitoring Program, and the Ground Water Protection Initiative Program during decommissioning. Each will likely be modified somewhat to reflect changes in site configuration, etc.
- SCE will comply with all applicable NRC and DOT regulations, including Federal Railroad Administration regulations and requirements, and use approved packaging and shipping containers for the shipping of radiological waste. SCE will also comply with State of California regulations enforced by Caltrans and the California Highway Patrol.

- SCE will continue to comply with federal, state, and local requirements for non-radiological interfaces with the environment including limitations on water withdrawal and discharges, air emissions including criteria pollutants and fugitive dust, noise levels, protection of avian, terrestrial and aquatic species, cultural resources, disposal of non-radiological waste, and worker health protection.
- SCE will seek and comply with an amendment to its CSLC easement lease to largely abandon the intake and discharge conduits in place.
- SCE will seek and comply with a coastal development permit from the CCC for decommissioning.

V. REFERENCES

A. GENERAL DEVELOPMENTAL REFERENCES

1. NRC Regulatory Guide 1.185, Revision 1, June 2013, Standard Format and Content Guide for Post-Shutdown Decommissioning Activities Report
2. Energy*Solutions* Document No. 164001, "2014 Decommissioning Cost Analysis of the San Onofre Nuclear Generating Station Units 2 and 3"
3. Enercon Technical Data Record No. SONGS002, "SONGS Units 2 and 3 Environmental Impact Evaluation"

B. SPECIFIC REFERENCES IN TEXT

1. Letter from Thomas J. Palmisano (SCE) to the U. S. Nuclear Regulatory Commission dated February 13, 2014; Subject: Access to Nuclear Decommissioning Trust Funds, San Onofre Nuclear Station, Units 2 and 3.
2. Letter from Richard C. Brabec (SCE) to the U. S. Nuclear Regulatory Commission dated March 31, 2014; Subject: Decommissioning Funding Status Report, San Onofre Nuclear Generating Station Units 2 and 3
3. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission dated June 12, 2013; Subject: Certification of Permanent Cessation of Power Operations San Onofre Nuclear Generating Station, Units 2 and 3
4. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission dated June 28, 2013; Subject: Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station Unit 3
5. Letter from P. T. Dietrich (SCE) to the U. S. Nuclear Regulatory Commission dated July 22, 2013; Subject: Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station Unit 2
6. U. S. Nuclear Regulatory Commission; NUREG-0586, "Final Generic Environmental Impact Statement (GEIS) on Decommissioning Nuclear Facilities" (November 2002)
7. AIF/NESP-036, "A Guideline for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates"
8. U.S. Nuclear Regulatory Commission, NUREG-0490, "Final Environmental Statement related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3" (April 1981)
9. U. S. Nuclear Regulatory Commission, NUREG-2157, "Waste Confidence Generic Environmental Impact Statement, Report for Comment" (August 2014)
10. U. S. Nuclear Regulatory Commission, NUREG-1496, Volume 1, "Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities" (July 1997)
11. NEI 07-07, "Industry Groundwater Protection Initiative, Final Guidance Document," in August 2007

EXHIBIT 2

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Thomas J. Palmisano
Vice President & Chief Nuclear Officer

10 CFR 50.82(a)(4)(i)

September 23, 2014

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

Subject: **Docket Nos. 50-361 and 50-362,**
San Onofre Nuclear Generating Station, Units 2 and 3
Irradiated Fuel Management Plan

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

Dear Sir or Madam:

On June 12, 2013, SCE submitted the referenced letter to the U.S. Nuclear Regulatory Commission (NRC) certifying the permanent cessation of operations at San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, in accordance with 10 CFR 50.54(bb) and 10 CFR 50.82(a)(4)(i), Southern California Edison (SCE) is required to submit an Irradiated Fuel Management Plan (IFMP), Site Specific Decommissioning Cost Estimate (DCE) and Post-Shutdown Decommissioning Activities Report (PSDAR) within two years of permanent cessation of operations.

The SONGS, Units 2 and 3 IFMP is attached. The DCE and PSDAR are being concurrently submitted under separate cover letters. The IFMP represents SCE's current plans and is subject to change as the project progresses. In particular, the Independent Spent Fuel Storage Installation location, and storage equipment and vendor(s) have not been selected. The decision making and procurement activities are underway but have not been finalized.

Changes to significant details will be included in subsequent revisions to the IFMP as required by 10 CFR 50.54(bb). Financial assurance information will be provided on an annual basis as required by 10 CFR 50.75(f)(1).

This letter does not contain any new commitments.

If there are any questions or if additional information is needed, please contact me or Ms. Andrea Sterdis at (949) 368-9985.

Sincerely,

P.O. Box 128
San Clemente, CA 92672
(949) 368-6575 PAX 86575
Fax: (949) 368-6183
Tom.Palmisano@sce.com

A001
NRR

Enclosure: San Onofre Nuclear Generating Station Units 2 and 3 Irradiated Fuel Management Plan

cc: M. L. Dapas, Regional Administrator, NRC Region IV
T. J. Wengert, NRC Project Manager, SONGS, Units 2 and 3
T. J, Warnick, NRC Project Manager, San Onofre Units 2 and 3 Decommissioning
R. E. Lantz, NRC Region IV, San Onofre Units 2 and 3
S. Y. Hsu, California Department of Health Services, Radiologic Health Branch

I. Background and Introduction

On June 12, 2013, Southern California Edison (SCE) submitted a letter to the U.S. Nuclear Regulatory Commission (NRC) (Reference 1) certifying the permanent cessation of operations at San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 effective June 7, 2013, in accordance with 10 CFR 50.82(a)(1)(i). All fuel was removed from the SONGS Units 2 and 3 reactor vessels and placed in their respective spent fuel pools as certified in accordance with 10 CFR 50.82(a)(1)(ii) (References 2 and 3).

Pursuant to 10 CFR 50.54(bb), licensees are required to submit a plan for the management of irradiated fuel until title and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository. The Irradiated Fuel Management Plan (IFMP) is required to be submitted to the Commission either five years before expiration of the Operating License or within two years following permanent cessation of operations, whichever occurs first. Therefore, the SONGS Units 2 and 3 plans are required to be submitted prior to June 7, 2015, two years following the cessation of operations. This submittal constitutes SCE's IFMP for SONGS Units 2 and 3, submitted on behalf of itself and the other SONGS Participants responsible for the funding of the SONGS decommissioning. The other SONGS Participants are the City of Anaheim, the City of Riverside, and San Diego Gas & Electric Company (SDG&E).

Energy*Solutions*, LLC has prepared a site-specific decommissioning cost estimate (DCE) for SONGS Units 2 and 3 (Reference 15). The DCE identifies the details, schedules, and costs of spent fuel management activities associated with the IFMP, along with license termination and site restoration activities and costs. This DCE is being submitted concurrent with the Post-Shutdown Decommissioning Activities Report (PSDAR, Reference 4) and this plan. The assumptions regarding the United States Department of Energy (US DOE) acceptance of irradiated fuel is consistent with the Energy*Solutions* DCE and is based on testimony filed with the California Public Utility Commission (Reference 13). The SONGS Units 2 and 3 DCE and this IFMP are based on commencement of industry-wide acceptance of spent fuel by US DOE in 2024.

II. Irradiated Fuel Management Strategy

The safe initial interim storage of SONGS Units 2 and 3 irradiated fuel will be "wet storage" in each unit's respective spent fuel pool. The spent fuel pools will be isolated from their normal support systems and those systems replaced by stand-alone cooling and filtration units (also termed a "spent fuel pool island"). Doing so facilitates earlier system abandonment and parallel decommissioning activities.

Subsequently, all irradiated fuel in the SONGS Units 2 and 3 spent fuel pools will be safely transferred to "dry storage" at the common Independent Spent Fuel Storage Installation (ISFSI) located on the SONGS site. Dry storage is also considered interim storage pending transfer to the US DOE.

A total of 1,726 irradiated fuel assemblies have been generated in SONGS Unit 2 and 1,734 irradiated fuel assemblies have been generated in SONGS Unit 3, for a total of 3,460 irradiated fuel assemblies. At present, 792 SONGS Units 2 and 3 irradiated fuel assemblies have already been transferred to the common ISFSI. The remaining 2,668 irradiated fuel assembles will be loaded into Dry Shielded Canisters (DSCs) and transferred to the ISFSI.

The current ISFSI is located inside the Owner Controlled Area. It was constructed to accommodate SONGS Unit 1 irradiated fuel and provides additional capacity for a limited amount of SONGS Units 2 and 3 irradiated fuel.

The ISFSI currently contains 18 DSCs storing Unit 1 fuel and Greater than Class C (GTCC) waste. The ISFSI also contains 33 DSCs which store Units 2 and 3 fuel. All of the fuel on the ISFSI is stored in Transnuclear NUHOMS Model Number-24PT1 or PT4 DSCs.

The major IFMP activity phases, including start and end dates and associated costs for each period are identified in Table 1. The identified Spent Nuclear Fuel (SNF) Periods are developed in and align with the site-specific DCE (Reference 15).

The current plans are to obtain necessary permits for the ISFSI to be expanded to accommodate the remaining inventory of the SONGS Units 2 and 3 spent fuel pools. SONGS plans to commence the movement of irradiated fuel from the Unit 2 and Unit 3 pools to the ISFSI in 2017. SONGS expects to complete the transfer in 2019. Additional DSCs will be procured from one or more of the available dry storage system suppliers beginning in 2014. An additional 47 DSCs will be required for the SONGS Unit 2 irradiated fuel and an additional 44 DSCs will be required for the SONGS Unit 3

irradiated fuel (depending on the capacity of the selected system and the number of DSCs needed to store GTCC waste and other materials). The spent fuel pool inventory is forecast to be transferred to the ISFSI no later than the end of 2019.

The US DOE Standard Contracts for acceptance and disposal of spent nuclear fuel and high level waste contain the basis for the initial ranking of industry-wide spent fuel acceptance obligations based upon the date of permanent removal of the spent nuclear fuel from service ("oldest fuel first" allocation). Those Standard Contracts also contain provisions allowing for "exchanges" of acceptance obligations, and priority for retired units. Given the US DOE's lack of performance, a common assumption for purposes of this fuel management plan is to base acceptance projections upon application of an "oldest fuel first" allocation scheme to a projected start date for repository operations. This plan is based upon a 2024 start date (Reference 13) for US DOE acceptance of spent fuel from the industry and the SONGS Units 2 and 3 positions in the queue. As indicated in Table 3, SCE is therefore assuming all fuel will be removed from the SONGS site as of 2049. Based on this assumption, the ISFSI will be subsequently decommissioned by the 2051 final license termination date.

III. Financial Assurance

The regulations (10 CFR 50.54(bb)) also require that funding adequacy be demonstrated to support the irradiated fuel management plan.

The cost of twelve (12) additional DSCs to be stored on the current ISFSI was funded from sources other than the Nuclear Decommissioning Trusts (NDT) (Reference 5), as are the costs associated with ongoing storage of Unit 1 spent fuel at the GE-Hitachi Nuclear America LLC's Morris Operation ISFSI located in Morris, Illinois. Table 1 includes the costs of procurement and construction of the expanded ISFSI capacity and all loading costs. Operation of the spent fuel pools is modeled as being discontinued in 2019 after all of the fuel has been transferred to dry storage. ISFSI operations continue until the US DOE is able to complete the transfer of the SONGS fuel to a repository or interim storage facility, which is currently assumed to occur by 2049.

SONGS management is committed to providing consistent and up-to-date information to all of its stakeholders and regulators. Aspects of the SONGS Nuclear Decommissioning Trust Fund are regulated by both the California Public Utilities Commission (CPUC) and the NRC. Previous Decommissioning Cost Estimates (DCEs) were updated and submitted to the CPUC as part of the Nuclear Decommissioning Cost Triennial Proceedings (Reference 5). Financial assurance reports including the balances and expenditures for SONGS Unit 1 were supplied to the NRC (as required by 10 CFR

50.82(a)(8)(v)) annually (most recently in Reference 6) and balances for SONGS Units 2 and 3 were submitted on a biennial basis (as required by 10 CFR 50.75(f)(1)) (most recently in Reference 7). Reports regarding ISFSI costs and decommissioning funding assurance for these costs were summarized triennially as required by 10 CFR 72.30(c) (most recently in Reference 8). Going forward, balances and expenditures will be supplied annually to the NRC for all three units and the ISFSI.

An updated site-specific DCE will be concurrently submitted to the NRC. As summarized in Table 1, this plan is based on decommissioning and the termination of the license by 2051, approximately 38 years following the permanent cessation of operations. The summary in Table 1 includes the funds for dry storage through 2049 and final release of the ISFSI in 2051.

Tables 4A and 4B summarize the estimated annual spending for all decommissioning activities (License Termination, Spent Fuel Management, and Site Restoration), and combined NDT current balances in 2014 dollars. Table 2 reflects key tasks addressed by the NRC staff in a recent safety evaluation.

The total of all Nuclear Decommissioning Trust funds balances for SONGS Units 2 and 3 was $3,926 million as of December 31, 2013 (Reference 9). Evaluation of the projected cash flows assuming earnings on existing balances as permitted by NRC regulations demonstrates the adequacy of the existing funds to cover all aspects of decommissioning, including the costs of irradiated fuel management. This demonstrates that the balance in the decommissioning trust is adequate to fund all aspects of decommissioning as well as the costs of irradiated fuel management. As decommissioning proceeds the DCE will be updated as appropriate and annual updates of spending and trust fund balances will be docketed as required.

IV. Regulatory Activities

The IFMP assumes that the SONGS Participants will make withdrawals from their nuclear decommissioning trusts for spent fuel management purposes. The SONGS Participants have collected funds from ratepayers and accumulated funds in the nuclear decommissioning trusts for the purpose of funding three primary categories of costs: (1) License Termination; (2) Spent Fuel Management; and (3) Site Restoration. On November 18, 2013, SCE filed a Tier 3 Advice Letter (Reference 10) with the CPUC to obtain authorization for the use of funds in the near term and to establish processes for further CPUC oversight of withdrawals from the nuclear decommissioning trusts. On February 21, 2014, SDG&E filed a similar letter (Reference 14) with the CPUC. In addition to authorizing and overseeing the withdrawals, the CPUC is expected to

designate the specific amounts from the existing fund balances that are available for License Termination and therefore subject to 10 CFR 50.82(a)(8)(i)(A) and 10 CFR 50.75(h)(2). The fund balances would then be allocated to separate subaccounts within each trust fund and, as such, available for spent fuel management and site restoration, consistent with the requirements of 10 CFR 50.75, 10 CFR 50.82, and 10 CFR 72.30.

To confirm such access, SCE requested (Reference 11) an exemption from 10 CFR 50.75 and 50.82 to authorize the use of trust funds to pay for spent fuel management and site restoration including other transitional costs. The regulations limit the use of the nuclear trust fund to decommissioning costs. This exemption was granted on September 5, 2014 (Reference 12).

The SONGS Participants responsible for decommissioning will periodically review the amount of cash contributions required for the decommissioning fund to ensure that withdrawals do not inhibit the ability of the licensee to complete NRC License Termination, Spent Fuel Management, and Site Restoration. The SONGS Participants will obtain authorization as necessary through the ratemaking processes to provide for further contributions if required.

In accordance with 10 CFR 50.82(a)(8)(vii), SONGS will annually submit to the NRC by March 31st a report on the status of the funding for managing spent fuel. The report will include, current through the end of the previous calendar year, the amount of funds accumulated to cover the cost of managing the spent fuel, the projected cost of managing spent fuel until title to the fuel and possession of the fuel is transferred to the Secretary of Energy, and if the funds accumulated do not cover the projected cost, a plan to provide additional funding assurance using one of the methods allowed by NRC regulations.

V. References

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

2. Letter from P. Dietrich, Southern California Edison, to U.S. Nuclear Regulatory Commission, Subject: Dockets 50-361 Permanent Removal of Fuel from Reactor Vessel, San Onofre Nuclear Generating Station, Unit 2, dated July 22, 2013

3. Letter from P. Dietrich, Southern California Edison, to U.S. Nuclear Regulatory Commission, Subject: Dockets 50-362 Permanent Removal of Fuel from Reactor Vessel, San Onofre Nuclear Generating Station, Unit 3, dated June 28, 2013

4. SONGS Units 2 and 3 Post-Shutdown Decommissioning Activities Report, San Onofre Nuclear Generating Station

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

6. Letter from Richard C. Brabec, Southern California Edison to U. S. Nuclear Regulatory Commission, Subject: 10 CFR 50.75(f)(1) and 10 CFR 50.82(a)(8)(v-vii) Decommissioning Funding Status Report San Onofre Nuclear Generating Station Unit 1 dated March 31, 2014

7. Letter from Richard C. Brabec, Southern California Edison to U. S. Nuclear Regulatory Commission, Subject: 10 CFR 50.75(f)(1) Decommissioning Funding Status Report, San Onofre Nuclear Generating Station Units 2 and 3 dated March 31, 2014

8. Letter from Douglas R. Bauder, Southern California Edison U. S. Nuclear Regulatory Commission , Subject: 10 CFR 72.30 ISFSI Decommissioning Funding Plan, San Onofre Nuclear Generating Station Units 1, 2 & 3 dated December 14, 2012

9. Letter from Richard C. Brabec, Southern California Edison to U.S. Nuclear Regulatory Commission, Subject: San Onofre Nuclear Generating Station, Units 2 and 3 Access to Nuclear Decommissioning Trust Funds, Supplemental Information, Dated March 12, 2014

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

11. Letter from Tom J. Palmisano, Southern California Edison, to U. S. Nuclear Regulatory Commission, Subject: San Onofre Nuclear Generating Station Units 2 and 3, Access to Nuclear Decommissioning Trust Funds, dated February 13, 2014

12. Letter from Thomas Wengert, Nuclear Regulatory Commission to Tom J. Palmisano, Southern California Edison, Granting Exemptions from the Requirements of 10 CFR 50, Sections 50.82(a)(8)(i)(A) and 50.75(h)(2) (TAC Nos. MF3544 an MF 3545) dated September 5, 2014

13. Testimony on Nuclear Decommissioning of SONGS 2 & 3 and Palo Verde, exhibit No. SCE-2, dated December 21, 2012

14. Letter from Clay Faber, San Diego Gas & Electric, to Public Utilities Commission of the State of California submitting a Tier 3 Advice Letter Requesting (1) Designation of SONGS 2&3 Costs Incurred During and After June 2013 As Decommissioning Costs Eligible for Payment with Trust Funds; (2) Authorization of Disbursements from the Master Trusts for San Onofre Nuclear Generating Station; (3) Approval of Tier 2 Advice Letter Process for Future Trust Disbursements; (4) Acknowledgement That Funds Have Been Collected From Ratepayers and Have Been Accumulating In The Trusts To Be Used for NRC and Non-NRC Jurisdictional Decommissioning Cost Categories; and (5) Designation of an Allocation of the SDG&E SONGS 2&3 Trusts Among the Major Decommissioning Cost Categories, dated February 21, 2014

15. EnergySolutions Document No. 164001, "2014 Decommissioning Cost Analysis of the San Onofre Nuclear Generating Station Units 2 and 3"

Table 1

Irradiated Fuel Management Plan – Summary Schedule

Cost and Schedule Summary (2014 Dollars in thousands)							
Spent Fuel 10 CFR 50.54(bb)							
Period No.	**Period Description**	**Start**	**End**	**Years**	**Unit 2 Cost**	**Unit 3 Cost**	**Total Cost**
SNF Pd 1	Spent Fuel Management Transition	6/7/2013	12/31/2013	0.56	$63,891	$66,105	$129,997
SNF Pd 2	Spent Fuel Transfer to Dry Storage	1/1/2014	6/1/2019	5.41	$344,629	$372,193	$716,822
SNF Pd 3	Dry Storage During Decommissioning – Units 1, 2 and 3	6/1/2019	12/5/2031	12.51	$61,425	$61,425	$122,849
SNF Pd 4	Dry Storage Only – Units 1, 2 and 3	12/5/2031	12/31/2035	4.07	$29,383	$29,383	$58,765
SNF Pd 5	Dry Storage Only – Units 2 and 3	12/31/2035	12/31/2049	14.00	$107,326	$107,326	$214,653
SNF D&D Pd 1	ISFSI License Termination	12/31/2049	5/6/2050	0.34	$1,260	$1,260	$2,520
SNF D&D Pd 2	ISFSI Demolition	5/6/2050	9/8/2051	1.34	$15,295	$15,295	$30,590
	Category Total			**38.23**	**$623,209**	**$652,987**	**$1,276,196**

Table 2
Major Fuel Management Tasks

Major Fuel Management Task Direct Costs (Note 1)	Explanatory or Additional Details	Estimate in DCE (in Thousands)	Schedule in DCE
Estimated Costs to isolate spent fuel pools and fuel handling systems	• Estimated cost for Islanding • No additional costs are required for fuel handling systems. Cranes are single-failure proof	$ 22,183 (Note 2)	6/2015
Estimated cost to construct an ISFSI or a combination of wet/dry storage	• ISFSI in operation; so, current costs are for wet/dry combination. • Costs are associated with capacity expansion (pad and associated facility costs, DSCs and HSMs).	$ 396,391 (Note 3)	6/2019
Estimated annual cost for the operation of the selected option	• Operational and maintenance costs are NOT readily separable (fuel storage support vice other demands); but, are included in Table 4 cash flows.	N/A	Ongoing
Estimated cost for preparation, packaging and shipping of fuel to DOE	• Off-site transportation costs are part of contract with US DOE.	$ 6,742 (Note 4)	Thru 12/2049
Estimated cost to decommission the ISFSI	• Funded from both Unit 1 and Units 2&3 Decommissioning Trust Funds.	$ 33,110 (Note 5)	2049-2051
Brief discussion of selected storage method or methods and estimated time frame for these activities	• See Section II for selected methods. • See Table 1 for time frames.	N/A	N/A

Notes:

1. Tasks from NRC Safety Evaluation (SE) on Kewaunee Integrated Fuel Management Plan dated, September 28, 2009, publically available under ADAMS Accession No. ML092321079
2. Cost based on DCE, DECON Pd 2, Items 2.23 through 2.30
3. Cost based on DCE, SNF Pd 2, Items 8.05 through 8.13
4. Cost based on SNF Pd 4 and SNF Pd 5, Item 2.03
5. Cost based on DCE, total of SNF D&D Pd 1 and SNF Pd 2

Table 3

SONGS Unit 2 & Unit 3
Spent Fuel Shipping Schedule
2024 DOE Acceptance

	On-Site Inventory (Beginning of the Year)				On-Site Transfers (During Year)		Off-Site Transfers (During Year)			
Year	Unit 2 & 3 Fuel Assemblies in Wet Storage	Units 2 & 3 Fuel Assemblies in Dry Storage	Units 2 & 3 Fuel Assemblies in On-Site Storage	Units 2 &3 Canisters in ISFSI	Unit 2 & 3 Fuel Assemblies Transferred to ISFSI	Unit 2 & 3 Canisters Transferred to ISFSI	Unit 2 Assemblies Transferred to DOE	Unit 3 Assemblies Transferred to DOE	Unit 2 & 3 Assemblies Transferred to DOE	Unit 2 & 3 Canisters Transferred to DOE
2014	2668	792	3460	33	0	0	0	0	0	0
2015	2668	792	3460	33	0	0	0	0	0	0
2016	2668	792	3460	33	0	0	0	0	0	0
2017	2668	792	3460	33	768	24	0	0	0	0
2018	1900	1560	3460	57	1536	48	0	0	0	0
2019	364	3096	3460	105	364	13	0	0	0	0
2020	0	3460	3460	118	0	0	0	0	0	0
2021	0	3460	3460	118	0	0	0	0	0	0
2022	0	3460	3460	118	0	0	0	0	0	0
2023	0	3460	3460	118	0	0	0	0	0	0
2024	0	3460	3460	118	0	0	0	0	0	0
2025	0	3460	3460	118	0	0	0	0	0	0
2026	0	3460	3460	118	0	0	0	0	0	0
2027	0	3460	3460	118	0	0	0	0	0	0
2028	0	3460	3460	118	0	0	0	0	0	0
2029	0	3460	3460	118	0	0	0	0	0	0
2030	0	3460	3460	118	0	0	48	48	96	4
2031	0	3364	3364	114	0	0	192	96	288	12
2032	0	3076	3076	102	0	0	120	120	240	10
2033	0	2836	2836	92	0	0	0	96	96	4
2034	0	2740	2740	88	0	0	112	120	232	8
2035	0	2508	2508	80	0	0	96	96	192	6
2036	0	2316	2316	74	0	0	128	96	224	7
2037	0	2092	2092	67	0	0	0	0	0	0
2038	0	2092	2092	67	0	0	96	128	224	7
2039	0	1868	1868	60	0	0	96	96	192	6
2040	0	1676	1676	54	0	0	96	96	192	6
2041	0	1484	1484	48	0	0	0	0	0	0
2042	0	1484	1484	48	0	0	96	96	192	6
2043	0	1292	1292	42	0	0	96	96	192	6
2044	0	1100	1100	36	0	0	96	96	192	6
2045	0	908	908	30	0	0	128	96	224	7
2046	0	684	684	23	0	0	96	128	224	7
2047	0	460	460	16	0	0	96	230	326	11
2048	0	134	134	5	0	0	0	0	0	0
2049	0	134	134	5	0	0	134	0	134	5
2050	0	0	0	0	0	0	0	0	0	0

Note: The number of canisters listed are for storage of irradiated fuel not GTCC waste.

Table 4A
SONGS Unit 2
Decommissioning Funding Plan

Year	Radiological Decontamination	Spent Fuel Management	Site Restoration	Total Decommissioning Costs	Available Funds
2013	$25,749	$63,891	$49,067	$138,706	$1,847,000
2014	$79,799	$35,719	$15,089	$130,607	
2015	$69,196	$106,308	$7,439	$182,943	
2016	$54,541	$59,308	$3,730	$117,579	
2017	$111,903	$59,308	$1,957	$173,168	
2018	$47,520	$59,308	$0	$106,828	
2019	$108,328	$27,554	$13,539	$149,420	
2020	$185,482	$4,908	$36	$190,426	
2021	$79,081	$4,908	$36	$84,026	
2022	$54,785	$4,908	$1,927	$61,621	
2023	$158,207	$4,908	$36	$163,151	
2024	$37,930	$4,908	$16,848	$59.687	
2025	$2,922	$4,908	$44,621	$52,451	
2026	$2,922	$4,908	$19,412	$27,243	
2027	$2,922	$4,908	$22,469	$30,299	
2028	$2,922	$4,908	$31,688	$39,518	
2029	$2,922	$4,908	$66,873	$74,704	
2030	$2,922	$4,908	$71,867	$79,697	
2031	$2,055	$5,089	$23,181	$30.325	
2032	$2,122	$7,214	$0	$9,336	
2033	$0	$7,214	$0	$7,214	
2034	$0	$7,214	$0	$7,214	
2035	$0	$7,228	$0	$7,228	
2036	$0	$7,665	$0	$7,665	
2037	$0	$7,665	$0	$7,665	
2038	$0	$7,665	$0	$7,665	
2039	$0	$7,665	$0	$7,665	
2040	$0	$7,665	$0	$7,665	
2041	$0	$7,665	$0	$7,665	
2042	$0	$7,665	$0	$7,665	
2043	$0	$7,665	$0	$7,665	
2044	$0	$7,665	$0	$7,665	
2045	$0	$7,665	$0	$7,665	
2046	$0	$7,665	$0	$7,665	
2047	$0	$7,665	$0	$7,665	
2048	$0	$7,665	$0	$7,665	
2049	$0	$7,667	$0	$7,667	
2050	$0	$9,974	$20,177	$30,151	
2051	$0	$6,573	$11,928	$18,500	
2052	$0	$0	$1,377	$1,377	

Notes: Costs are in 2014 dollars (in thousands) and are not escalated from the base year
SONGS Unit 2 Trust fund balances at end of 2013 were $1,847,000

Table 4B
SONGS Unit 3
Decommissioning Funding Plan

Year	Radiological Decontamination	Spent Fuel Management	Site Restoration	Total Decommissioning Costs	Available Funds
2013	$26,566	$66,105	$49,067	$141,739	$2,079,400
2014	$78,964	$40,156	$15,969	$135,089	
2015	$74,096	$112,024	$9,390	$195,509	
2016	$61,451	$64,405	$25,227	$151,083	
2017	$40,631	$64,405	$3,799	$108,835	
2018	$86,348	$64,405	$0	$150,753	
2019	$96,521	$29,675	$13,908	$140.014	
2020	$120,873	$4,908	$2,135	$127,916	
2021	$194,090	$4,908	$575	$199,574	
2022	$135,313	$4,908	$2,467	$142,688	
2023	$114,581	$4,908	$1,511	$121,000	
2024	$26,874	$4,908	$36,778	$68,560	
2025	$2,922	$4,908	$40,655	$48,485	
2026	$2,922	$4,908	$21,676	$29,507	
2027	$2,922	$4,908	$25,848	$33,678	
2028	$2,922	$4,908	$20,945	$28,776	
2029	$2,922	$4,908	$117,321	$125,151	
2030	$2,922	$4,908	$116,672	$124,503	
2031	$2,055	$5,089	$25,501	$32,645	
2032	$2,122	$7,214	$0	$9,336	
2033	$0	$7,214	$0	$7,214	
2034	$0	$7,214	$0	$7,214	
2035	$0	$7,228	$0	$7,228	
2036	$0	$7,665	$0	$7,665	
2037	$0	$7,665	$0	$7,665	
2038	$0	$7,665	$0	$7,665	
2039	$0	$7,665	$0	$7,665	
2040	$0	$7,665	$0	$7,665	
2041	$0	$7,665	$0	$7,665	
2042	$0	$7,665	$0	$7,665	
2043	$0	$7,665	$0	$7,665	
2044	$0	$7,665	$0	$7,665	
2045	$0	$7,665	$0	$7,665	
2046	$0	$7,665	$0	$7,665	
2047	$0	$7,665	$0	$7,665	
2048	$0	$7,665	$0	$7,665	
2049	$0	$7,667	$0	$7,667	
2050	$0	$9,974	$23,120	$33,094	
2051	$0	$6,573	$45,566	$52,139	
2052	$0	$0	$1,377	$1,377	

Notes: Costs are in 2014 dollars (in thousands) and are not escalated from the base year
SONGS Unit 3 Trust Fund balances at end of 2013 were $2,079,400

EXHIBIT 3

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Thomas J. Palmisano
Vice President & Chief Nuclear Officer

10 CFR 50.82(a)(4)(i)

September 23, 2014

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

Subject: Docket Nos. 50-361 and 50-362,
San Onofre Nuclear Generating Station, Units 2 and 3
Site Specific Decommissioning Cost Estimate

References:

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

2. Letter from Thomas J. Palmisano (SCE) to the U.S. Nuclear Regulatory Commission dated February 13, 2014; Subject: Access to Nuclear Decommissioning Trust Funds, San Onofre Nuclear Station, Units 2 and 3

3. Letter from Richard C. Brabec (SCE) to the U.S. Nuclear Regulatory Commission dated March 12, 2014; Subject: Access to Decommissioning Trust Funds, San Onofre Nuclear Generating Station Units 2 and 3

4. Letter from Richard C. Brabec (SCE) to the U.S. Nuclear Regulatory Commission dated March 31, 2014; Subject: 10 CFR 50.75(f)(1) Decommissioning Funding Status Report, San Onofre Nuclear Generating Station Units 2 and 3

Dear Sir or Madam:

On June 12, 2013, in accordance with 10 CFR 50.82(a)(1)(i), Southern California Edison (SCE) submitted a letter to the U.S. Nuclear Regulatory Commission (NRC) (Reference 1) certifying the permanent cessation of operations at San Onofre Nuclear Generating Station (SONGS), Units 2 and 3. In accordance with 10 CFR 50.54(bb) and 10 CFR 50.82(a)(4)(i), SCE is required to submit an Irradiated Fuel Management Plan (IFMP), Site Specific Decommissioning Cost Estimate (DCE) and Post-Shutdown Decommissioning Activities Report (PSDAR) within two years of permanent cessation of operations.

The SONGS, Units 2 and 3 DCE is attached. The SONGS, Units 2 and 3 IFMP and PSDAR are being concurrently submitted under separate cover letters. The DCE provides more current estimates of annual cash flow than were previously provided in the Nuclear Decommissioning Trust Fund Exemption Request (References 2 and 3) and annual funding assurance update (Reference 4). Future filings with the California Public Utilities Commission will be based on the SONGS, Units 2 and 3 DCE and subsequent revisions.

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A001
NRR

The descriptions of decommissioning activities and phases in the DCE are consistent with those described in the PSDAR. Both the DCE and PSDAR represent SCE's current plans and are subject to change as the project progresses. Much of the third-party contracting activities associated with decommissioning are underway but have not been finalized. As contracts are finalized and SCE progresses through the actual work of the decommissioning project, various risks will be realized or avoided and contingencies adjusted, accordingly.

Changes to significant details will be included in subsequent revisions to the DCE as required by 10 CFR 50.54(bb). Financial assurance information will be provided on an annual basis as required by 10 CFR 50.75(f)(1).

This letter does not contain any new commitments.

If there are any questions or if additional information is needed, please contact me or Ms. Andrea Sterdis at (949) 368-9985.

Sincerely,

Enclosure: San Onofre Nuclear Generating Station Units 2 and 3 Site Specific Decommissioning Cost Estimate

cc: M. L. Dapas, Regional Administrator, NRC Region IV
T. J. Wengert, NRC Project Manager, San Onofre Units 2 and 3 Decommissioning
R. E. Lantz, NRC Region IV, San Onofre Units 2 and 3
G. G. Warrick, NRC Senior Resident Inspector, San Onofre Units 2 and 3
S. Y. Hsu, California Department of Health Services, Radiologic Health Branch

ENERGYSOLUTIONS

Document No. 164001-DCE-001

2014 Decommissioning Cost Analysis of the San Onofre Nuclear Generating Station Units 2 & 3

Project No. 164001 **Rev 1**

Prepared for:
Southern California Edison.
2244 Walnut Grove Avenue
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Authored By:	Michael S. Williams, Project Manager	September 5, 2014 Date
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Approved By	Michael S. Williams, Project Manager	September 5, 2014 Date

- [ ] New Report
- [ ] Title Change
- [x] Report Revision
- [ ] Report Rewrite

Effective Date Sept 5, 2014

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SONGS UNIT-2 AND UNIT-3
DECOMMISSIONING COST ESTIMATE
DESCRIPTION OF REVISION

MAJOR REVISION _____ MINOR REVISION_X____
REVISION NUMBER – 1 EFFECTIVE DATE - 9/5/2014

The revisions contained in this MINOR REVISION to the SONGS Unit-2 and Unit-3 Decommissioning Cost Estimate are minor in nature and do not revise or otherwise impact the content or results of the cost estimate.

ITEM-1

A new Appendix-F is added to the DCE at the request of San Diego Gas & Electric Company (SDG&E) in order to provide information regarding its internal decommissioning costs which it expects to incur and to fund on its own behalf in addition to its 20% share of the Decommissioning Cost Estimate.

ITEM-2

The APPENDICES section of the DCE Table of Contents is revised to include the new APPENDIX-F SDG&E SONGS Decommissioning Costs (100%)

ITEM-3

Within the narrative section of the DCE the various appearances of the term "utility staff" have been revised to include a parenthetic statement "(Licensee)" to clarify that the utility staff means the NRC Licensee.

ITEM-4

On Table 6-1 "Cost and Schedule Summary" the title block for SPENT FUEL is revised to include "(72.30)" since this section also contains cost elements associated with ISFSI decommissioning.

ITEM-5

Added new SDG&E footnote for Table 1-1 referring to Appendix F

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ACRONYMS AND ABBREVIATIONS

AHSM	Advanced Horizontal Storage Modules
AIF	Atomic Industrial Forum
ALARA	As Low As Reasonably Achievable
ARO	Asset Retirement Obligation
CFR	Code of Federal Regulations
CPM	Critical Path Method
DAW	Dry Active Waste
DGC	Decommissioning General Contractor
DOE	U.S. Department of Energy
DSC	Dry Shielded Canister
ESS	Essential System
FEMA	Federal Emergency Management Agency
FSS	Final Status Survey
FTE	Full Time Equivalent
GSA	U.S. General Services Administration
GTCC	Greater Than Class C
HP	Health Physics
ISFSI	Independent Spent Fuel Storage Installation
LLRW	Low-Level Radioactive Waste
LLW	Low Level Waste
LLWPA	Low-Level Waste Policy Act
LOP	Life-of-Plant
MARSSIM	Multi-Agency Radiation Survey and Site Investigation Manual
MPC	Multi-Purpose Canister
MWt	Megawatt thermal
NON	Non-Essential System
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
ORISE	Oak Ridge Institute for Science and Education
PCB	Polychlorinated Biphenyl
PGE	Pacific Gas & Electric
PSDAR	Post-Shutdown Decommissioning Activities Report
PWR	Pressurized Water Reactor
RIF	Reduction In Force
SCE	Southern California Edison
SONGS	San Onofre Nuclear Generating Station
STRUCT	Structure
TCEQ	Texas Commission on Environmental Quality
WBS	Work Breakdown Structure
WCS	Waste Control Specialists LLC
UCF	Unit Cost Factor

1.0 EXECUTIVE SUMMARY

This report presents the 2014 Decommissioning Cost Estimate (DCE) Study of the San Onofre Nuclear Generating Station (SONGS) Units 2 & 3, hereinafter referred to as the 2014 Cost Study. The San Onofre Nuclear Generating Station is operated by the Southern California Edison Company (SCE).

On June 7, 2013, SCE announced its intention to permanently cease power generation operations and shut down SONGS Units 2 & 3. Units 2 & 3 had not produced power since January 9, 2012 and January 31, 2012, respectively. SCE now has the responsibility to decommission the site. In January 2014 SCE contracted with Energy*Solutions* to evaluate decommissioning alternatives and assist in the development of a detailed project schedule and DCE to support the preparation and submittal of a Post Shutdown Decommissioning Activities Report (PSDAR) in accordance with 10 CFR 50.82(a)(4)(i), which requires that a PSDAR be submitted within two years following the permanent cessation of operations.

This study has been performed to furnish an estimate of the costs for: (1) decommissioning SONGS Units 2 & 3 to the extent required to terminate the plant's operating license pursuant to 10 CFR 50.75(c); (2) post-shutdown management of spent fuel until acceptance by the U.S. Department of Energy (DOE) pursuant to 10 CFR 50.54(bb); (3) demolition of uncontaminated structures and restoration of the site in accordance with the United States Department of Navy Grant of Easement (Ref. No. 14); and the California State Lands Commission Easement Lease (Ref. No. 15); and (4) Independent Spent Fuel Storage Installation (ISFSI) decommissioning pursuant to 10 CFR 72.30. This study includes SCE's actual costs incurred in the transitional periods following cessation of permanent operations on June 7, 2013 until December 31, 2013. Costs presented herein commencing on January 1, 2014 are estimated.

SCE's December 2012 testimony to the CPUC provided the basis for the current spent fuel management costs. SCE is continuing to review available information from the DOE to determine if the DOE start date assumption of 2024 requires updating. The DCE will be revised accordingly as new information becomes available.

Accordingly, the costs and schedules for all activities are segregated for regulatory purposes as follows: costs for "License Termination" (10 CFR 50.75(c)); costs for "Spent Fuel Management" (10 CFR 50.54(bb)); costs for "Site Restoration" (clean removal and site restoration) final site conditions; and costs for "ISFSI Decommissioning" (10 CFR 72.30). Energy*Solutions* has established a Work Breakdown Structure (WBS) and cost accounting system to differentiate between these project accounts.

This study analyzes the following technical approach to decommissioning as defined by SCE:

- DECON methodology.
- Permanent cessation of operations on June 7, 2013.
- Termination of spent fuel pool operation six years after permanent shutdown.
- Spent fuel will be stored in Multi-Purpose Canisters (MPCs) at an on-site Independent Spent Fuel Storage Installation (ISFSI).

- A dry transfer facility will not be necessary for transfer of SNF canisters for transport.
- DOE begins accepting spent fuel from the industry in 2024 and completes the removal of all SONGS spent fuel by 2049.
- Decommissioning will be performed by a Decommissioning General Contractor (DGC) with oversight by the SONGS participants.
- Incorporation of Life-of-Plant (LOP) Disposal Rates for Class A Low-Level Radioactive Waste (LLRW).
- Incorporation of disposal rates for Class B and C LLRW based on recent quotes for disposal at the Waste Control Specialists LLC (WCS) site in Andrews County, Texas.

The cost estimate results are provided in Table 1-1. Table 1-1 gives License Termination costs (which correspond to 10 CFR 50.75 (c) requirements); Spent Fuel Management costs (which correspond to 10 CFR 50.54 (bb) requirements); and Site Restoration costs (which correspond to activities such as clean building demolition and site grading and end-state preparation as required under the Site Easement).

Table 1-1
Decommissioning Cost Summary[1][2]
(2014 Dollars in Thousands)

Cost Account	Unit 2	Unit 3	Total
License Termination 50.75(c)	$1,034,230	$1,078,016	**$2,112,246**
Spent Fuel Management 50.54(bb)	$623,209	$652,987	**$1,276,196**
Site Restoration	$423,297	$599,507	**$1,022,804**
Totals	**$2,080,735**	**$2,330,511**	**$4,411,246**

The estimate is based on site-specific plant systems and buildings inventories. These inventories, and Energy*Solutions*' proprietary Unit Cost Factors (UCFs), were used to generate required manhours, activity schedule hours and costs, and waste volume, weight, and classification. Based on the activity schedule hours and a decommissioning activities analysis, a Critical Path Method (CPM) analysis was performed to determine the decommissioning schedules. These schedules reflect the effects of sequenced activity-dependent or distributed decommissioning elements such as planning and preparations, major component removal, building decontamination, and spent fuel shipping. The schedules are divided into project phases (periods) and presented, as noted previously, by cost account "License Termination," "Spent Fuel Management," or "Site Restoration." The summary is shown in Figure 1-1, and may also be found in Section 6.0 of this report.

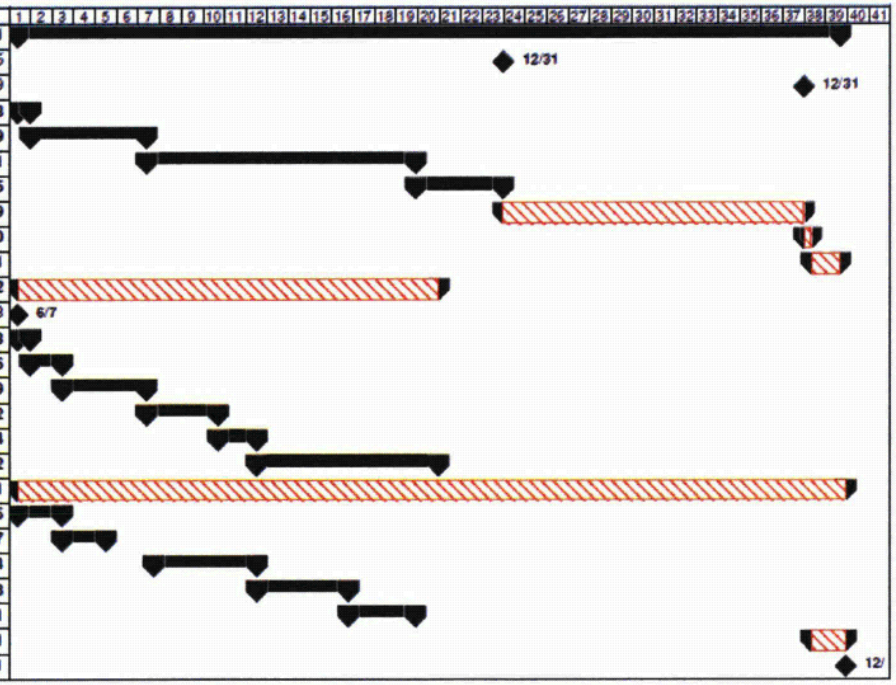
[1] In addition, the Decommissioning Cost Summary in Table 1-1 does not include separate internal costs that San Diego Gas & Electric Company (SDG&E) has indicated that it expects to incur. SDG&E provides information regarding these costs in Appendix F

[2] Rows and columns may not add correctly due to rounding.

Figure 1-1
Summary Schedule

DECON with Dry Storage, 2013 Shutdown and DOE Acceptance in 2024

Task Name	Start	Finish
Post-Shutdown Spent Fuel Management	06/07/2013	09/08/2051
Spent Fuel Shipping Complete - Unit 1	12/31/2035	12/31/2035
Spent Fuel Shipping Complete - Units 2 & 3	12/31/2049	12/31/2049
SNF Pd 1 - Spent Fuel Management Transition	06/07/2013	12/31/2013
SNF Pd 2 - Spent Fuel Transfer to Dry Storage	1/1/2014	06/01/2019
SNF Pd 3 - Dry Storage During Decommissioning - Units 1, 2 and 3	06/01/2019	12/05/2031
SNF Pd 4 - Dry Storage Only - Units 1, 2 and 3	12/05/2031	12/31/2035
SNF Pd 5 - Dry Storage Only - Units 2 and 3	12/31/2035	12/31/2049
SNF D&D Pd 1 - ISFSI D&D Planning	12/31/2049	05/06/2050
SNF D&D Pd 2 - ISFSI D&D	05/06/2050	09/08/2051
Part 50 License Termination	06/07/2013	12/24/2032
Announcement of Cessation of Operations (June 7, 2013)	06/07/2013	06/07/2013
Decon Pd 1 - Transition to Decommissioning	06/07/2013	12/31/2013
Decon Pd 2 - Decommissioning Planning and Site Modifications	1/1/2014	06/30/2015
Decon Pd 3 - Decommissioning Preparations and Reactor Internals Segmentation	06/30/2015	06/01/2019
Decon Pd 4 - Plant Systems and Large Component Removal	06/01/2019	09/24/2022
Decon Pd 5 - Building Decontamination	09/24/2022	07/13/2024
Decon Pd 6 - License Termination During Demolition	07/13/2024	12/24/2032
Site Restoration	06/07/2013	12/15/2051
SR Pd 1 - Transition to Site Restoration	06/07/2013	06/30/2015
SR Pd 2 - Building Demolition During Decommissioning	06/30/2015	07/11/2017
SR Pd 3 - Subsurface Demolition Engineering and Permitting	10/01/2019	07/13/2024
SR Pd 4 - Building Demolition to 3 Feet Below Grade	07/13/2024	10/14/2028
SR Pd 5 - Subgrade Structure Removal Below -3 Feet	10/14/2028	12/05/2031
SR Pd 6 - Final Site Restoration and Lease Termination	05/06/2050	12/15/2051
Final Easement Termination	12/15/2051	12/15/2051



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2.0 INTRODUCTION

2.1 Study Objective

This report presents the 2014 Decommissioning Cost Estimate Study of the San Onofre Nuclear Generating Station (SONGS) Units 2 & 3, hereinafter referred to as the 2014 Cost Study. The San Onofre Nuclear Generating Station is owned by the Southern California Edison Company (SCE), San Diego Gas & Electric Company, and the City of Riverside. A former owner, the City of Anaheim, also has liability for decommissioning. SCE has provided the following information regarding the liability by owner for SONGS decommissioning costs:

Cost Categories	Owners			
	SDG&E	Riverside	Anaheim	SCE
SONGS 1	20%	0%	0%	80%
SONGS 2	20%	1.79%	2.4737%	75.7363%
SONGS 3	20%	1.79%	2.4625%	75.7475%
Common Facilities (Units 2 & 3)	20%	1.79%	2.4681%	75.7419%
SONGS 1 Fuel	20%	0%	0%	80%
SONGS 2/3 Fuel	20%	1.79%	2.3398%	75.8702%
ISFSI Maintenance and D&D	20%	1.6066%	2.2686%	76.1248%
San Diego Switchyard	100%	0%	0%	0%
Edison Switchyard	0%	0%	0%	100%
Interconnection Facilities	50%	0%	0%	50%
Nuclear Fuel Cancellation Charges	20%	1.79%	0%	78.21%

This study has been performed to support the development of a site-specific PSDAR and furnish an estimate of the costs for (1) decommissioning SONGS Units 2 & 3 to the extent required to terminate the plant's operating license, (2) post-shutdown management of spent fuel until acceptance by the U.S. Department of Energy (DOE), (3) demolition of uncontaminated structures and restoration of the site in accordance with the U.S. Department of Navy Grant of Easement (Ref. No. 14), and the California State Lands Commission Easement Lease (Ref. No. 15), and (4) Independent Spent Fuel Storage Installation (ISFSI) decommissioning. This study also includes SCE's actual costs incurred in the transitional periods following cessation of permanent operations until December 31, 2013. Estimated costs begin on January 1, 2014.

The study methodology follows the basic approach originally presented in the Atomic Industrial Forum/National Environmental Studies Project Report AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," (Ref. No. 2). The report was prepared in accordance with Nuclear Regulatory Commission (NRC) Regulatory Guide 1.202, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," (Ref. No. 3). The estimate is based on compliance with current regulatory requirements and proven decommissioning technologies.

NRC requirements, set forth in Title 10 of the Code of Federal Regulations (CFR), differentiate between the post-shutdown costs associated with the decommissioning of the nuclear plant facility, those associated with storage of spent fuel on-site, and those associated with the decommissioning of the spent fuel storage facility. The Code of Federal Regulations, however, does not address the entire scope of the decommissioning liability for each nuclear facility. 10 CFR 50.75(c) requires funding by the licensee(s) of the facility for the decommissioning program, but specifically excludes the cost of removal and disposal of spent fuel and structures that do not require disposal as radioactive material. 10 CFR 50.75(c) also excludes the cost of site restoration activities that do not involve the removal of residual radioactivity necessary to terminate the NRC license(s). 10 CFR 50.54 (bb) requires funding by the licensee(s) "for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license(s) until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository." 10 CFR 72.30 requires funding for decommissioning of the on-site spent fuel storage facility after the irradiated fuel is accepted by the DOE.

In addition to the NRC Decommissioning requirements described above, the Site Easements require the demolition and removal of all improvements installed on both the on-shore and off-shore sites, including all substructures regardless of depth, and site restoration to the satisfaction of the Grantors.

This study analyzes the following technical approach to decommissioning as defined by SCE and the co-owners:

- DECON methodology.
- Permanent cessation of operations and commencement of decommissioning planning on June 7, 2013.
- Termination of spent fuel pool operation within six years after permanent shutdown.
- Spent fuel will be stored in transportable Multi-Purpose Canisters (MPCs) at an on-site Independent Spent Fuel Storage Installation (ISFSI).
- A dry transfer facility will not be necessary for transfer of SNF canisters for transport.
- DOE begins accepting spent fuel from the industry in 2024 and completes the removal of all SONGS spent fuel by 2049.
- Decommissioning will be performed by a Decommissioning General Contractor (DGC) with oversight by the SONGS participants.

In addition, this study includes the following assumptions:

- Incorporation of Energy*Solutions*' Life-of-Plant (LOP) Disposal Rates for Class A Low-Level Radioactive Waste (LLRW), (Ref. No. 7).
- Incorporation of disposal rates for Class B and C LLRW based on recent quotes for disposal at the Waste Control Specialists LLC (WCS) site in Andrews County, Texas.

2.2 Regulatory Framework

Provisions of current laws and regulations affecting decommissioning, waste management, and spent fuel management are as follows:

1. NRC regulations require a license for on-site storage of spent fuel. Wet storage in a spent fuel pool is authorized by a facility's 10 CFR Part 50 license. On-site dry storage of spent fuel at an Independent Spent Fuel Storage Installation (ISFSI) is licensed by either: (a) the general license set forth in 10 CFR 72.210, which requires that a Part 50 license be in place; or (b) a site-specific ISFSI license issued pursuant to 10 CFR Part 72.

2. 10 CFR 50.75(c) requires funding by the licensee(s) of the facility for decommissioning.

3. 10 CFR 50.54 (bb) requires the licensee(s), within two years following permanent cessation of operation of the reactor or five years before expiration of the operating license(s), whichever occurs first, to submit written notification to the NRC for its review and preliminary approval of the program by which the licensee intends to manage and provide funding "for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository."

4. 10 CFR 961 (Ref. No. 4), Appendix E, requires spent fuel to be cooled for at least five years before it can be accepted by DOE as "standard spent fuel."

5. 10 CFR 72.30 requires funding by the licensee(s) for termination of the ISFSI license.

<u>Decommissioning Alternatives</u>

The three basic methods for decommissioning are DECON, SAFSTOR, and ENTOMB, which are summarized as follows:

1. DECON: The equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the license after cessation of operations.

2. SAFSTOR: The facility is placed in a safe, stable condition and maintained in that state (safe storage). The facility is decontaminated and dismantled at the end of the storage period to levels that permit license termination. NRC regulations require decommissioning to be completed within 60 years of cessation of operation.

3. ENTOMB: Radioactive structures, systems, and components are encased in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained and monitored until radioactivity decays to a level that permits termination of the license. Since entombment will exceed the requirement

for decommissioning to be completed within 60 years of cessation of operation, NRC handles entombment requests on a case-by-case basis.

Post-Shutdown Spent Fuel Management Alternatives

The options for long-term post-shutdown spent fuel management currently available to power plant operators are (1) wet storage consisting of continued maintenance and operation of the spent fuel pool, and (2) dry storage consisting of transfer of spent fuel from the fuel pool to on-site dry storage modules after a cooling period or any combination of the two as is the present case at SONGS. Maintaining the spent fuel pool for an extended duration following cessation of operations prevents termination of the Part 50 license and typically has a higher annual maintenance and operating cost than the dry storage alternative. Transfer of spent fuel to an ISFSI requires additional expenditures for purchase and construction of the ISFSI and dismantlement and disposal of the ISFSI following completion of spent fuel transfer to DOE.

The spent fuel shipping schedules furnished by SCE for this study are based on projections that DOE will commence accepting spent fuel from domestic commercial nuclear power plants in 2024, and that the DOE will accept spent fuel at the rate published in DOE's July 2004 Acceptance Priority Ranking & Annual Capacity Report (DOE/RW-0567) (Ref. No. 12). These assumptions are in accordance with SCE testimony to the Public Utilities Commission of the State of California (Ref. No. 17). Additionally, SCE is reviewing available information from the DOE to determine if the DOE start date assumption requires updating. The DCE will be revised accordingly as new information becomes available.

3.0 STUDY METHODOLOGY

3.1 General Description

Energy*Solutions* maintains a proprietary decommissioning cost model based upon the fundamental technical approach established in AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," dated May 1986 (Ref. No. 2). The cost model has been updated frequently in accordance with regulatory requirements and industry experience. The cost model includes elements for estimating distributed and undistributed costs. Distributed costs are activity specific and include planning and preparation costs as well as costs for decontamination, packaging, disposal, and removal of major components and systems. For example, costs for the segmentation, packaging, and disposal of the reactor internals are distributed costs. Undistributed costs, sometimes referred to as collateral costs, are typically time dependent costs such as utility (Licensee) and decommissioning general contractor staff, property taxes, insurance, regulatory fees and permits, energy costs, and security staff.

The methodology for preparing cost estimates for a selected decommissioning alternative requires development of a site-specific detailed work activity sequence based upon the plant inventory. The activity sequence is used to define the labor, material, equipment, energy resources, and duration required for each activity. In the case of major components, individual work sequence activity analyses are performed based on the physical and radiological characteristics of the component, and the packaging, transportation, and disposal options available.

In the case of structures and small components and equipment such as piping, pumps, and tanks, the work durations and costs are calculated based on UCFs. UCFs are economic parameters developed to express costs per unit of work output, piece of equipment, or time. They are developed using decommissioning experience, information on the latest technology applicable to decommissioning, and engineering judgment. The total cost of a specific decommissioning activity can be determined by multiplying the total number of units associated with that activity by the UCF, expressed as $/unit, for that activity. For example, the estimated demolition cost of a non-contaminated concrete structure can be obtained by multiplying the volume of concrete in the structure by the UCF for non-contaminated reinforced concrete demolition, expressed in $/unit volume. Each UCF has associated with it a man-hours/unit and schedule-hours/unit. From these values, total man-hours and total schedule-hours can be estimated for a particular activity.

3.2 Schedule Analysis

After the work activity durations are calculated for all distributed activities, a critical path schedule analysis is performed using MS Project. The schedule accounts for constraints such as spent fuel cooling periods and regulatory reviews. The schedule is typically delineated into phases or time periods (hereinafter referred to as period or periods) that differentiate manpower requirements and undistributed costs.

In order to differentiate between License Termination, Spent Fuel, and Site Restoration elements of the entire decommissioning scope of work, Energy*Solutions* has established a Work Breakdown Structure (WBS) and cost accounting system to treat each element as a subproject.

Accordingly, the overall project schedule is divided into interrelated periods with major milestones defining the beginning and ending of each period. The major milestones also serve as the basis for integrating the periods of the three subprojects.

3.3 Decommissioning Staff

Energy*Solutions* has assumed that the SONGS Units 2 and 3 decommissioning project will be performed in an efficiently planned and executed manner using project personnel experienced in decommissioning. This DCE assumes that the decommissioning will be performed by a highly experienced and qualified DGC, with oversight and management of the decommissioning operations performed by the Licensee staff. It is also assumed that the Utility (Licensee) staff will be supplemented by a professional consulting engineering firm, particularly in the planning and preparation phase.

Energy*Solutions* analyzed the SONGS licensee staff and developed a site-specific staffing plan. The SCE existing salary structure was then used as the basis for calculating Utility (Licensee) staff labor costs. Energy*Solutions* used industry data to develop DGC salary costs.

Staffing levels, for both staffing plans and for each project period, are based on the Atomic Industrial Forum (AIF) guidelines and industry experience. The sizes of the staffs are varied in each period in accordance with the requirements of the work activities. Staffing has been organized into the following departments or functional groups:

- Decommissioning
- Engineering
- Maintenance and Work Control
- Operations
- Oversight and Nuclear Safety
- Radiation Protection and Chemistry
- Regulatory and Emergency Planning
- Safety and Human Performance
- Security Administration
- Security Guard Force
- Site Management and Administration
- Additional Staff for Spent Fuel Shipping
- DGC Staff

3.4 Waste Disposal

Waste management costs comprise a significant portion of the decommissioning cost estimate. Additionally, limited future access to disposal sites licensed for receipt of Class B and C wastes introduces a significant level of uncertainty with respect to the appropriateness of using existing rate structures to estimate disposal costs of these wastes. Energy*Solutions*' approach to estimating waste disposal costs is discussed in the following paragraphs.

<u>Waste Classification</u>

Regulations governing disposal of radioactive waste are stringent in order to ensure control of the waste and preclude adverse impact on public health and safety. At present, LLRW disposal

is controlled by 10 CFR 61, which went into effect in December 1983. This regulation stipulates the criteria for the establishment and operation of shallow-land LLRW burial facilities. Embodied within this new regulation are criteria and classifications for packaging LLRW such that it is acceptable for burial at licensed LLRW disposal sites.

For each waste classification, 10 CFR 61 stipulates specific criteria for physical and chemical properties that the LLRW must meet in order to be accepted at a licensed disposal site. The LLRW disposal criteria of 10 CFR 61 require that LLRW generators determine the proportional amount of a number of specific radioactive isotopes present in each container of disposable LLRW. This requirement for isotopic analysis of each container of disposable LLRW is met by employing a combination of analytical techniques such as computerized analyses based upon scaling factors, sample laboratory analyses, and direct assay methods. Having performed an isotopic analysis of each container of disposable LLRW, the waste must then be classified according to one of the classifications (Class A, B, C, or Greater Than Class C (GTCC)) as defined in 10 CFR 61.

Energy*Solutions*' classification of LLRW resulting from decommissioning activities is based on AIF/NESP-036 (Ref. No. 2), NUREG/CR-0130 (Ref. No. 5), NUREG/CR-0672 (Ref. No. 6), and recent industry experience. The estimated curie content of the reactor vessel and internals at shutdown is derived from NUREG/CR-0130 for Pressurized Water Reactors (PWRs) and NUREG/CR-0672 for Boiling Water Reactors (BWRs), and adjusted for the different mass of components and period of decay.

Packaging

Selection of the type and quantity of containers required for Class B and C wastes is based on the most restrictive of either curie content, dose-rate, container weight limit, or container volume limit. GTCC wastes from segmentation of the reactor vessel internals is packaged in spent fuel canisters. The selection of container type for Class A waste is based on the transportation mode (rail, truck, barge, etc.) and waste form. The quantity of Class A waste containers is determined by the most restrictive of either container weight limit or container volume limit. Large components, such as steam generators, pressurizers, and reactor recirculation pumps, are shipped as their own containers with additional shielding as required.

Container costs are obtained from manufacturers specializing in the design and fabrication of storage containers for nuclear materials. Shielded transport cask and liner costs are obtained from the cask owners and operators.

Transportation

Transportation routes to processing and disposal facilities are determined based on available transportation modes (truck, rail, barge, or combinations). Transportation costs for the selected routes and modes are obtained from vendor quotes or published tariffs whenever possible.

Class A Disposal Options and Rates

In accordance with the existing Life-of-Plant Disposal Agreement (Ref. No. 7), all Class A waste that meets the waste acceptance criteria are to be disposed of at Energy*Solutions'* LLRW

disposal facility in Clive, Utah. All reported waste disposal costs include packaging, transportation, and any applicable surcharges.

Class B and C Disposal Options and Rates

Currently, within the United States, there are only three operational commercial near-surface disposal facilities licensed to accept Class B and C LLRW: the Barnwell facility, operated by Energy*Solutions* in Barnwell, South Carolina; the U.S. Ecology facility in Richland, Washington; and the recently licensed facility in Andrews County, Texas operated by Waste Control Specialists. Barnwell only accepts waste from states within the Atlantic Compact and U.S. Ecology only accepts waste from states within the Northwest and Rocky Mountain Compacts. However, the WCS facility will accept waste from the Texas Compact (comprised of Texas and Vermont) and from non-Compact generators. The Texas Compact Commission on March 23, 2012 approved amendments to rules allowing the import of non-compact generator LLRW for disposal at the WCS Andrews County facility.

Greater Than Class C (GTCC)

Wastes identified as 10 CFR 61 Class A, B, and C may be disposed of at near-surface disposal facilities. Certain components are highly activated and may exceed the radionuclide concentration limitations for 10 CFR 61 Class C waste. In accordance with 10 CFR 61, these components, which are referred to as Greater Than Class C (GTCC) wastes, cannot be disposed of in a near-surface LLRW disposal facility and must be transferred to a geologic repository or a similar site approved by the NRC.

Highly activated sections of the reactor vessel internals will result in GTCC waste. Presently, a facility does not exist for the disposal of wastes exceeding 10 CFR 61 Class C limitations. Energy*Solutions* assumes that the DOE will accept this waste along with spent fuel. Although courts have held that DOE is obligated to accept and dispose of GTCC, issues regarding potential costs remain potentially unsettled. Therefore, Energy*Solutions* conservatively estimates a GTCC waste disposal cost. Energy*Solutions* assumes that the GTCC waste will be packaged in spent fuel canisters and will be shipped to a storage or disposal facility operated by DOE along with the spent fuel. Additionally, Energy*Solutions* assumes shipping costs for GTCC waste to be equivalent to the commercial cost of shipping a Type B licensed, shielded cask such as the CNS 8-120B cask, which is owned and operated by Energy*Solutions*.

LLRW Volume Reduction

Becasue current Class A LLRW disposal rates are significantly lower than LLRW volume reduction rates, Energy*Solutions* does not assume on-site volume reduction techniques such as waste compaction or an aggressive decontamination, survey and release effort.

Non-Radioactive Non-Hazardous Waste Disposal

Energy*Solutions* assumes that recyclable, non-radioactive scrap metal resulting from the decommissioning program will be sold to a scrap metal dealer. However, no cost credit is assumed in the estimate for the value of the scrap metal. Clean (non-contaminated) concrete and demolition debris is assumed to be removed off site to an out of state Class III landfill consistent

with the Governor of the State of California Executive Order D-62-02 (Ref. No. 16). This study includes the costs of installation and operation of Energy*Solutions*' GAmma Radiation Detection and In-container ANalysis or GARDIAN System. The GARDIAN System performs radiological assays of bulk shipping containers. The GARDIAN System is a cost effective and efficient means to ensure all non-radiological waste and recyclable materials arising from the decommissioning and demolition of the SONGS' site comply with all applicable regulatory requirements.

Hazardous and Industrial Waste Disposal

Uncontaminated lead shielding remaining after shutdown was assumed to be removed from its installed locations and shipped offsite by entities having a need for the material. The entities will receive the lead at no charge in return for providing the removal and shipping services. Non-Radioactive contaminated surfaces coated with tightly adhering and undamaged lead based paint will be removed as non-hazardous building demolition debris. All other chemicals and hazardous materials present at shutdown will be removed and properly disposed of during decommissioning.

3.5 Final Status Survey

The cost of performing a final status survey (FSS) is based on NUREG-1575, "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)," (Ref. No. 8). Estimates of MARSSIM Class I, II, and III survey designations are based on radiological assumptions regarding contamination resulting from small and large component removal activities. The FSS activity cost calculation includes the in-place remote survey of underground metal and concrete pipe, soil, and groundwater sampling and analysis. Estimated costs for NRC and Oak Ridge Institute for Science and Education (ORISE) verification are also included, and the NRC review period is incorporated into the project schedule.

3.6 Contingency

Contingencies are applied to cost estimates primarily to allow for unknown or unplanned occurrences during the actual program, e.g., increased radioactive waste materials volumes over that expected; equipment breakdowns, weather delays, and labor strikes. This is consistent with the definition provided in the DOE Cost Estimating Guide, DOE G 430.1-1, 3-28-97 (DOE G) (Ref. No. 9). Contingency "covers costs that may result from incomplete design, unforeseen and unpredictable conditions, or uncertainties within the defined project scope. The amount of contingency will depend on the status of design, procurement, and construction; and the complexity and uncertainties of the component parts of the project. Contingency is not to be used to avoid making an accurate assessment of expected costs." Energy*Solutions* determines site-specific contingency factors to be applied to each estimate based on industry practices.

The DOE has established a recommended range of contingencies as a function of completeness of program design, DOE G. The ranges are:

Type of Estimate	Contingency Range as a % of Total Estimate
Planning Phase Estimate	20-30
Budget Estimate	15-25
Title I (Preliminary Design Estimate)	10-20
Title II (Definitive Design Estimate)	5-15

Also, the Pacific Gas & Electric Company (PG&E) Technical Position Paper "Establishing an Appropriate Contingency Factor for Inclusion in the Decommissioning Revenue Requirements" (Ref. No. 13) was developed to review and determine a "conservative contingency factor" to be applied to decommissioning cost estimates. In that study it was determined that "based on an understanding of the level of project definition, and the extent and maturity of estimate input information used to develop decommissioning cost estimates, the 25 percent contingency factor is within the range of industry recognized cost engineering practices."

The contingencies presented in this study are consistent with the values presented in DOE G 430.1-1 for a Planning Phase estimate (Ref. No. 9) and the PG&E study (Ref. No. 13). As directed by SCE, Energy*Solutions* has applied a 25% contingency to all costs in this study, with the exception of following:

2013 and 2014 Actual Expenditures	0%
Department of Navy Easement Payments	15%
Hazardous and Asbestos Wastes	50%
Site Characterization Surveys	15%
Temporary Facilities	15%
Backfill and Compaction	15%

A reactor decommissioning program will be conducted under an NRC-approved Quality Assurance Program which meets the requirements of 10 CFR 50, Appendix B. However, the development of the quality assurance program, the performance of work under that program, and the effort required to ensure compliance with the program, is already included in the detailed cost estimate. Therefore, Energy*Solutions* does not include quality assurance as an element of the contingency allowance. The same is true for contamination. Where radioactive contamination or activated materials are dealt with, the Energy*Solutions* UCFs and associated calculations fully reflect the cost impact of that material, and a separate contingency is not required specifically due to working with contamination.

3.7 Cost Reporting

Total project costs are aggregated from the distributed activity and undistributed costs into the following categories – Labor, Materials and Equipment, Waste Disposal, and Other costs. Other costs include property taxes, insurance, license fees, permits, and energy. Waste Disposal costs are the summation of packaging, transportation, base disposal rate, and any applicable surcharges. Health physics (HP) supplies and small tool costs are calculated as a component of each distributed activity cost and included in the category of Material and Equipment, with the exception that HP supplies for the Utility HP staff are calculated and reported as an undistributed line item. A line item specific contingency is then calculated for each activity cost element.

4.0 SITE SPECIFIC TECHNICAL APPROACH

4.1 Facility Description

The San Onofre Nuclear Generating Station Units 2 & 3 site is located in southern California on the shore of the Pacific Ocean, about 62 miles Southeast of Los Angeles and approximately 51 miles Northwest of San Diego. The station is located entirely within the Camp Pendleton Marine Corps Base. The current Grant of Easement for the site from the United States Department of the Navy is currently scheduled to expire May 12, 2023 (Ref. No. 14). Units 2 & 3 occupy 52.8 acres of the 84 acre site. Approximately 16 acres are occupied by the North Industrial Area (formerly Unit 1), which is where the existing ISFSI is located.

The Nuclear Steam Supply System (NSSS) for both units are identical, with two independent loops, and utilizing pressurized light water cooled reactors (PWRs) supplied by Combustion Engineering, Inc. The construction permit was issued for an initial reactor power of 3,390 MWt with licensed Rated Thermal Power of 3,438 MWt.

The facility currently has an existing ISFSI containing spent fuel that was transferred into MPCs to maintain full core offload capability during operations and to facilitate decommissioning of Unit 1. This study also assumes that the MPCs will be licensed under a 10 CFR Part 72 general license, using the manufacturer's Certificate of Compliance. The 10 CFR Part 50 license will be maintained until decommissioning is complete and all spent fuel has been transferred to DOE.

Appendix A provides a list of the SONGS Unit 2 & 3 systems and structures included in the material inventory for this study.

4.2 Decommissioning Periods

The project periods consist of six License Termination periods, seven Spent Fuel Management periods (two of which are ISFSI decontamination and demolition periods), and six Site Restoration periods. As shown in Figure 1-1 above, the periods for each of these project areas are independent from (do not compete with) the periods for the other project areas. The project periods defined for this site-specific study and the major activities performed during each period are as follows:

License Termination Periods

<u>Decon Pd 1 –Transition to Decommissioning</u>

- Defuel Reactors
- Notification of Permanent Fuel Removal
- Disposition of LLRW Resins

<u>Decon Pd 2 –Decommissioning Planning and Site Modifications</u>

- Preparation of Decommissioning License Documents
- Preparation of NRC Deliverables
- Submit PSDAR to NRC
- Perform Historical Site Assessment and Site Characterization
- Planning, Design, and Implementation of Cold & Dark (Site Repowering)

- Design and Implement Spent Fuel Pool Support System Modifications, Control Room Relocation, and Spent Fuel Security System Modifications

- Select Decommissioning General Contractor (DGC)

Decon Pd 3 – Decommissioning Preparations and Reactor Internal Segmentation
- DGC Mobilization and Planning
- System Decontamination
- Reactor Internals Removal Preparations
- Reactor Internals Segmentation Planning and Implementation
- Purchase Dry Storage Modules for GTCC Waste
- Segment and Package Reactor Internals for Storage in the ISFSI

Decon Pd 4 – Plant Systems and Large Component Removal
- Upgrade Rail Spur on 'Owner Controlled Area' (does not affect spur connecting to CALTRANS).
- Install Large Array Radiation Detection System
- Remove, Package, and Dispose of Non-Essential Systems
- Asbestos and Lead Abatement
- Fuel Pool Closure
- Remove Spent Fuel Racks, Spent Fuel Pool Island Equipment, and Bridge Cranes
- Remove and Dispose of Legacy Class B & C Wastes
- Remove, Package, and Dispose of Essential Systems
- Removal and Disposal of Spent Resins, Filter Media, and Tank Sludge
- Large Component Removal
- Prepare License Termination Plan

Decon Pd 5 – Building Decontamination
- Decon Containment Buildings – Units 2 & 3
- Decon Turbine Buildings – Units 2 & 3
- Decon Fuel Handling Buildings – Units 2 & 3
- Decon Auxiliary Radwaste Building
- Decon Auxiliary Control Building
- Decon Penetration Buildings – Units 2 & 3
- Decon Safety Equipment and Main Steam Isolation Valve Buildings – Units 2 & 3
- Radiological Survey of Structures During Decon

Decon Pd 6 – License Termination During Decommissioning
- Final Status Survey
- ORISE Verification and NRC Approval

Spent Fuel Management Periods

SNF Pd 1 – Spent Fuel Transfer Management Transition
- Implementation of Security Enhancements Required for Reductions in Staff
- Cyber Security Modifications
- Post Fukushima Modifications – Unit 2
- Design and Fabricate Spent Fuel Canisters

SNF Pd 2 – Spent Fuel Transfer to Dry Storage
- Prepare Irradiated Fuel Management Plan
- Select Dry Storage System Canister Design and Vendor
- Design and Construct ISFSI Expansion
- Purchase, Deliver and Load Spent Fuel Canisters and Transfer to ISFSI

SNF Pd 3 – Dry Storage During Decommissioning Units 1, 2, & 3

SNF Pd 4 – Dry Storage Only – Units 1, 2, & 3

SNF Pd 5 – Dry Storage Only – Units 2, & 3

SNF D&D Pd 1 – ISFSI License Termination
- Preparation and NRC Review of License Termination Plan

SNF D&D Pd 2 – ISFSI Demolition
- Verification Survey of Horizontal Storage Modules
- Clean Demolition of ISFSI AHSMs and Pads
- Clean Demolition of ISFSI Support Structures
- Restore ISFSI Site
- Preparation of Final Report on Decommissioning and NRC Review

Site Restoration Periods

SR Pd 1 –Transition to Site Restoration
- Severance Costs from Post-Shutdown Reduction in Staffing
- Phase I and II Environmental Assessment of the Mesa Site
- Disposition of Hazardous Waste at the Mesa Site
- Site Characterization of the Mesa Site

SR Pd 2 –Building Demolition During Decommissioning
- Demolish South Access for Decommissioning, South Yard Facility, and Mesa Structures
- Finish Grade and Re-vegetate Mesa Site
- Mesa Lease Termination

SR Pd 3 – Subsurface Demolition Engineering & Permitting
- Hydrogeologic Investigation and Outfall Conduit Survey
- Subsurface Structure Removal Analyses for Lease Termination Activities
- Final Site Grading and Shoreline Protection Engineering Planning and Design
- Obtain Permits and Approvals

SR Pd 4 – Building Demolition to 3 Feet Below Grade
- Demolition Preparations
- De-Tension and Remove Containment Building Tendons – Units 2 & 3
- Demolish Diesel Generator Buildings – Units 2 & 3
- Demolish Condensate Buildings and Transformer Pads – Units 2 & 3

- Demolish Full Flow Areas and Turbine Buildings – Units 2 & 3
- Demolish Auxiliary Radwaste Building
- Demolish Auxiliary Control Building
- Remove Systems and Demolish Make-up Demineralizer Structures
- Demolish Penetration Buildings – Units 2 & 3
- Demolish Safety Equipment and Main Steam Isolation Valve Buildings – Units 2 & 3
- Demolish Fuel Handling Buildings to 3 Feet Below Grade – Units 2 & 3
- Demolish Containment Buildings to 3 Feet Below Grade – Units 2 & 3
- Demolish Intake and Discharge Structures to 3 Feet Below Grade

SR Pd 5 – Subgrade Structure Removal Below – 3 Feet

- Install Sheet Piling and Excavation Shoring, Dewatering System, and Effluent Treatment and Discharge Controls
- Demolish and Backfill Unit 3 Subsurface Structures
- Demolish and Backfill Unit 2 Subsurface Structures
- Demolish and Backfill Common Subsurface Structures
- Demolish and Backfill Intake Structure Inside Seawall Below -3 Feet
- Remove Off Shore Intake and Outfall Conduits
- Remove Sheet Piling, Excavation Shoring, and Dewatering and Effluent Treatment
- Finish Grading and Re-vegetate Site

SR Pd 6 – Final Site Restoration and Easement Termination

- Obtain Required Permits and Approvals
- Install Dewatering System and Effluent Treatment and Discharge Controls
- Remove and Stockpile Existing Seawall Erosion Protection
- Remove Unit 2 & 3 Seawall and Pedestrian Walkway
- Remove Remaining Intake Structure Beneath Seawall
- Backfill and Compaction of Excavation
- Remove Dewatering System & Effluent Treatment
- Remove Railroad Tracks, Gunite Slope Protection, Access Road, and North Parking Lot
- Finish Grading and Re-vegetate Site

4.3 Decommissioning Staff

Energy*Solutions* developed staffing based on the assumption that decommissioning will be performed by an experienced and qualified DGC, with oversight and management of the decommissioning operations performed by the Utility (Licensee) staff. It is also assumed that the Utility staff will be supplemented by a professional consulting engineering firm, particularly in the planning and preparation phase. The sizes of the Utility (Licensee) and DGC staffs are varied in each period in accordance with the requirements of the work activities. Details on the staff levels, by functional group, during each period are provided in Section 6.0.

4.4 Spent Fuel Management Staff

The largest spent fuel staff is in place while the fuel pool is operational during the spent fuel cooling period and the fuel assemblies are being transferred to dry storage. After all spent fuel

has been removed from the spent fuel pool, the staff is reduced. During spent fuel pool operations and the dry storage period, the full-time spent fuel management staff is supplemented with part-time staff to support fuel movements. Details on the staff levels, by functional group, during each period are provided in Section 6.0.

4.5 Spent Fuel Shipments

The spent fuel shipping schedules are based in part on the DOE's "Acceptance Priority Ranking & Annual Capacity Report," dated July 2004. (Ref. No. 12). The information regarding existing fuel inventory, planned transfers to dry storage and DOE's projected date of 2024 for acceptance of spent fuel is based on information provided by SCE. The spent fuel shipping schedule is provided in Appendix B. The spent fuel shipment schedule is based upon best current information and assumptions, as qualified and described elsewhere in this study, including in Section 2.2 above.

5.0 BASES OF ESTIMATE AND KEY ASSUMPTIONS

The bases of, and key assumptions for, this site-specific decommissioning estimate are presented below:

1. SCE's actual decommissioning expenses incurred from the time of permanent cessation of operations on June 7, 2013 until December 31, 2013 are included in the estimate. All other decommissioning cost data used in this study is current as of 2014. Totals and subtotals have been rounded to significant figures.

2. Energy*Solutions* developed a prompt dismantlement (DECON) project schedule based on a permanent shutdown date of June 7, 2013.

3. The decommissioning will be performed using currently available technologies.

4. DOE currently has no plans, program, or schedule in place for acceptance of utility spent fuel. However, for purposes of this decommissioning cost estimate, certain simplifying assumptions must be made regarding the schedule and rate of DOE performance. Therefore, while DOE's Standard Contract governing the acceptance of SCE's spent fuel allows for alternative removal schedules, including priority for shutdown reactors and exchanges of allocations, for purposes of this estimate DOE acceptance from the industry is assumed to commence in 2024 in accordance with SCE testimony to the Public Utilities Commission of the State of California (Ref. No. 17). The spent fuel shipment schedules are based upon the assumption that the DOE will accept spent fuel at the rate published in DOE's July 2004 Acceptance Priority Ranking & Annual Capacity Report (DOE/RW-0567) (Ref. No. 12). Additionally, SCE is reviewing available information from DOE to determine if the DOE start date assumption requires updating. The DCE will be revised accordingly as new information becomes available.

5. This estimate is based on site-specific building inventories and plant systems, as provided by Energy*Solutions*.

6. All transformers on site following shutdown are assumed to be polychlorinated biphenyl (PCB)-free, therefore, this study does not include costs for disposition of PCB contaminated transformers.

7. Cost for transportation of clean scrap metal to a recycler is included in the estimate; however, no credit is taken for the value of the scrap metal. Concrete debris and all other demolition debris is assumed to be removed from the site and disposed of at an out of state Class III landfill, consistent with the Governor of the State of California Executive Order D-62-02 (Ref. No. 16). The cost of installation and operation of Energy*Solutions*' GARDIAN system for bulk radiological assay of all wastes and recyclable materials leaving the SONGS site is included in the estimate. The purpose of the GARDIAN system is to ensure all materials not intended for disposal at a licensed facility meet all applicable requirements.

8. The estimate is based on final site restoration, in which all existing and proposed structures, with the exception of the switchyard, will be removed. Clean demolition costs are based on the assumption that all site improvements will be removed in their entirety. Clean backfill will be imported and placed to re-establish grade. The entire disturbed area of the site is to be graded, to restore the natural grade to the extent possible, and seeded.

9. Uncontaminated lead shielding remaining is assumed to be removed from its installed locations and shipped offsite by entities having a need for the material. The entities receive the lead at no charge in return for providing the removal and shipping services.

10. Site-specific information regarding contaminated soil was used as a basis for calculation of current costs for their remediation. While no known radiological or chemical remediation is required at the switchyard or the Mesa, those areas will be addressed as part of the Baseline Characterization Survey and Historical Site Assessment. If the studies conclude that radiological or chemical remediation is required at the switchyard or the Mesa, the DCE will be amended. For radiological contamination found at either the switchyard or the Mesa, the DCE will be amended to include all subsequent cost estimates for the remediation, which will be paid for by the SONGS participants in accordance with their cost allocations for the 'Common Facilities'. Chemical remediation of the switchyards will be paid by either SCE or SDG&E owners of the respective switchyards.

11. Costs for hazardous waste disposal, as well as asbestos and lead abatement, are included in this study.

12. All Class A waste is assumed to be disposed of at Energy*Solutions*' facility in Clive, Utah, in accordance with the existing Life-of-Plant Disposal Agreement between Energy*Solutions* and Southern California Edison, dated January 18, 2014 (Ref. No. 7). The following 2014 disposal rates will be applied:

    Demolition Debris and Soil - $57.97/Cubic Foot plus 5% Utah taxes
    Oversized Debris - $111.31/Cubic Foot plus 5% Utah taxes
    Containerized Waste Facility - $214.50/Cubic Foot plus 12% Utah taxes
    Large Components - $289.87/Cubic Foot plus 5% Utah taxes
    Cask Shipments - $44,059/Cask plus 12% Utah taxes

    Class A waste includes Dry Active Waste (DAW) arising from the disposal of contaminated protective clothing and health physics supplies.

13. Class B, C, and GTCC waste disposal costs are based on recent quotes for disposal of activated hardware and resins at the WCS facility. All resins and filter waste is assumed to be Class B.

14. Shipping costs for the Class B and C waste are based on a distance of 1,079 miles one way from SONGS to the WCS site.

15. GTCC is not subject to the same storage and security requirements as spent fuel and therefore is not required to be stored on the ISFSI pad. But for purposes of this estimate and to facilitate decommissioning, GTCC waste generated from the segmentation of the reactor internals is assumed to be packaged in Dry Shielded Canisters (DSCs) and placed in Advanced Horizontal Storage Modules (AHSMs) in the ISFSI to await final disposition at a DOE repository.

16. It is assumed that a total of six DSCs per unit will be required for GTCC waste.

17. Reactor vessel and internals curie estimates were derived from the values for the Reference PWR vessel and internals in NUREG/CR-0130 (Ref. No. 5). These values were adjusted for decay period.

18. The Energy*Solutions* site-specific classification of radioactive wastes for the SONGS Plant identified that the spent fuel assemblies and two components within the reactor vessel (the Core Shroud Assembly and the Lower Core Grid Plate) will exceed Class C limitations.

19. The spent fuel shipments are based upon best current information and assumptions, as qualified and described elsewhere in this study, including in Section 2.2. above.

20. Spent fuel will remain in the spent fuel pool for six years before being transferred to the ISFSI.

21. The costs for ISFSI construction and transfer of spent fuel from Units 2 & 3 to dry storage were developed by SCE and furnished to Energy*Solutions*. Following completion of spent fuel transfers to dry storage the cost of maintenance and operation of the ISFSI is distributed between Units 1, 2 and 3 based on the relative percentages of spent fuel assemblies in storage. The percentages are 10, 45, and 45 for Units 1, 2, and 3, respectively. The exception is that all property taxes are solely the liability of Units 2 & 3. Following completion of SNF Pd 4 – Dry Storage Only Units 1, 2, and 3, all ISFSI maintenance and operating costs are assigned to Units 2 & 3 until the ISFSI D&D. During ISFSI D&D costs are distributed to all three units in the same percentages of 10, 45, and 45.

22. DOE has not committed to accept SCE's canistered spent fuel. But for purposes of this estimate, it is assumed that an SCE-funded dry storage facility will not be necessary.

23. Costs for ISFSI demolition are included in this estimate. SCE assumes that portions of the AHSM concrete will be activated.

24. Energy*Solutions* has assumed that the 10 CFR Part 50 license will be maintained until DOE has taken possession of the spent fuel.

25. SCE's annual ISFSI insurance premiums of $302,000 are assumed to be incurred until all fuel shipments have been completed and the structure is no longer in use.

26. SCE's Emergency Preparedness (FEMA) fees of $500,000 per year and California Office of Emergency Services fees of $2,800,000 per year are applied until the spent fuel pool is empty. These fees were supplied by SCE.

27. SCE's current annual property taxes are assumed to be reduced to a constant $1,500,000 per year. The property taxes are a license termination expense until the completion of decommissioning, and then a spent fuel management expense until completion of the ISFSI D&D.

28. Energy*Solutions* has included the annual NRC 10 CFR 171.15(c)(2) fees, for reactors in decommissioning of $231,000/yr per unit until decommissioning is completed as a license termination expense. Following completion of decommissioning, this expense is continued as a spent fuel management cost for maintenance of the 10 CFR Part 50 license.

29. Energy*Solutions* has included Environmental Permits and Fees of $1,900,000 per year as supplied by SCE.

30. Energy*Solutions* has included NRC inspection fees during each decommissioning period based on the type and level of activities being performed.

31. SONGS annual insurance premiums, in 2014 dollars as supplied by SCE, are as follows:

    Nuclear Property Primary - $4,878,099
    Nuclear Liability - $1,151,075
    Additional Liability, Non-Nuclear - $3,576,519
    Workers' Compensation - $180,335
    Property Insurance - $353,286

    The premium amounts have been adjusted by Energy*Solutions* in accordance with information furnished by SCE to meet the requirements of each period.

32. Site operating expenses expected to be incurred during decommissioning and spent fuel management are included in the estimate. These costs include materials and services, utilities (water, gas, phone), telecommunications equipment, non-process computers, personal computers and tools and equipment. These costs were calculated based on information provided by SCE and adjusted by Energy*Solutions* to match the requirements of each period, based on staffing levels.

33. Site Lease and Easement expenses of $2,300,000 per year until the Mesa lease is terminated are included in the estimate. Following termination of the Mesa lease the site lease and easement expenses are reduced to $299,920 per year. These costs are based on information provided by SCE.

34. Utility (Licensee) staff positions and average direct burdened salary (i.e. total compensation) data in 2014 dollars were supplied by SCE.

35. Severance costs for those employees terminated as a result of SONGS decommissioning, including those costs required under California law are included in the estimate. Severance costs for Reductions-in-Force (RIFs) that occurred immediately after shutdown, and during the course of spent fuel management and decommissioning are assumed to be a site restoration expense and are included in the estimate.

36. Severance costs per employee were provided by SCE.

37. DGC staff salaries, including overhead and profit, were determined by Energy*Solutions* and represent Energy*Solutions*' standard assumptions for these rates.

38. The professional personnel used for the planning and preparation activities, and DGC personnel, are assumed to be paid per diem at the rate of $204/day, based on per diem rates from U.S. General Services Administration (GSA) for Orange County, California.

39. Craft labor rates were taken from the CA Union Craft Rate Sheet, dated January 9, 2014. Craft labor rates for disciplines not provided in the rate sheet have been taken from the 2014 RS Means Labor Rates for the Construction Industry (Ref. No. 10), for Anaheim, CA. Since the skilled laborers are assumed to be supplied by the local union hall, they will not be paid per diem.

40. The security guard force included in this estimate has been sized in accordance with the current Design Basis Threat assessment.

41. This study follows the occupational exposure principles of As Low As Reasonably Achievable (ALARA) through the use of productivity loss factors that incorporate such items as the use of respiratory protection and personnel protective clothing. These factors increase the work duration and cost.

42. The costs of all required safety analyses and safety measures for the protection of the general public, the environment, and decommissioning workers are included in the cost estimates. This reflects the requirements of:

10 CFR 20	Standards for Protection Against Radiation
10 CFR 50	Domestic Licensing of Production and Utilization Facilities
10 CFR 61	Licensing Requirements for Land Disposal of Radioactive Waste
10 CFR 71	Packaging of Radioactive Material for Transport
10 CFR 72	Licensing Requirements for the Independent Storage of Spent Nuclear Fuel and High-Level Radioactive Waste
29 CFR 1910	Occupational Safety and Health Standards

49 CFR 170-189	Department of Transportation Regulations Governing the Transport of Hazardous Materials
Reg. Guide 1.159	Assuring the Availability of Funds for Decommissioning Nuclear Reactors

43. Activity labor costs do not include any allowance for delays between activities, nor is there any cost allowance for craft labor retained on site while waiting for work to become available.

6.0 STUDY RESULTS

This study analyzes the following technical approach to decommissioning as defined by SCE:

- Prompt DECON methodology.
- Permanent cessation of operations and commencement of decommissioning planning on June 7, 2013.
- Termination of spent fuel pool operation six years after permanent shutdown.
- Spent fuel will be stored in MPCs at an on-site ISFSI.
- A dry transfer facility will not be necessary for transfer of SNF for transport.
- Decommissioning will be performed by a DGC with oversight by the SONGS participants.
- LOP Disposal Rates are used for Class A LLRW.
- WCS Texas Disposal Rates are used for Class B and C LLRW.
- DOE begins accepting spent fuel from the industry in 2024.

Spent Fuel Shipping Schedule

The spent fuel shipping schedule is provided in Appendix B. Spent fuel shipments from the industry to DOE will begin in 2024. The spent fuel shipment schedules are based upon best current information and assumptions, as qualified and described elsewhere in this study, including in Section 2.2 above.

Cost and Schedule

Figure 6-1 is a summary project schedule. A detailed schedule is provided in Appendix C. Table 6-1 summarizes the period durations and total costs, including contingency, for License Termination, Spent Fuel, and Site Restoration activities. A detailed cost table is provided in Appendix D, and a table of annual expenditures is provided in Appendix E.

Project Staffing

This scenario is based on the assumption that decommissioning will be performed by an experienced and qualified DGC, with oversight and management of the decommissioning operations performed by the Licensee staff. Utility (Licensee) staffing levels, by organizational department and function, for each period are provided in Table 6-2. The DGC staffing levels, by organizational department and function, for each period are provided in Table 6-3.

LLRW Disposal Volumes

LLRW disposal is a significant element of the decommissioning project. The estimated cubic feet of waste are summarized as follows:

Waste Class	Unit 2	Unit 3	Total
Class A	1,832,961	1,819,680	3,652,641
Class B	7,600	7,600	15,200
Class C	4,095	4,095	8,190
GTCC	941	941	1,882

Waste disposal volumes and costs, itemized by packaging, transportation, surcharges and disposal costs by waste class and facility, are provided in Table 6-4. The waste disposal costs provided in Table 6-4 do not include contingency.

Figure 6-1
Summary Schedule

DECON with Dry Storage, 2013 Shutdown and DOE Acceptance in 2024

Task Name	Start	Finish
Post-Shutdown Spent Fuel Management	06/07/2013	09/08/2051
Spent Fuel Shipping Complete - Unit 1	12/31/2035	12/31/2035
Spent Fuel Shipping Complete - Units 2 & 3	12/31/2049	12/31/2049
SNF Pd 1 - Spent Fuel Management Transition	06/07/2013	12/31/2013
SNF Pd 2 - Spent Fuel Transfer to Dry Storage	1/1/2014	06/01/2019
SNF Pd 3 - Dry Storage During Decommissioning - Units 1, 2 and 3	06/01/2019	12/05/2031
SNF Pd 4 - Dry Storage Only - Units 1, 2 and 3	12/05/2031	12/31/2035
SNF Pd 5 - Dry Storage Only - Units 2 and 3	12/31/2035	12/31/2049
SNF D&D Pd 1 - ISFSI D&D Planning	12/31/2049	05/06/2050
SNF D&D Pd 2 - ISFSI D&D	05/06/2050	09/08/2051
Part 50 License Termination	06/07/2013	12/24/2032
Announcement of Cessation of Operations (June 7, 2013)	06/07/2013	06/07/2013
Decon Pd 1 - Transition to Decommissioning	06/07/2013	12/31/2013
Decon Pd 2 - Decommissioning Planning and Site Modifications	1/1/2014	06/30/2015
Decon Pd 3 - Decommissioning Preparations and Reactor Internals Segmentation	06/30/2015	06/01/2019
Decon Pd 4 - Plant Systems and Large Component Removal	06/01/2019	09/24/2022
Decon Pd 5 - Building Decontamination	09/24/2022	07/13/2024
Decon Pd 6 - License Termination During Demolition	07/13/2024	12/24/2032
Site Restoration	06/07/2013	12/15/2051
SR Pd 1 - Transition to Site Restoration	06/07/2013	06/30/2015
SR Pd 2 - Building Demolition During Decommissioning	06/30/2015	07/11/2017
SR Pd 3 - Subsurface Demolition Engineering and Permitting	10/01/2019	07/13/2024
SR Pd 4 - Building Demolition to 3 Feet Below Grade	07/13/2024	10/14/2028
SR Pd 5 - Subgrade Structure Removal Below -3 Feet	10/14/2028	12/05/2031
SR Pd 6 - Final Site Restoration and Lease Termination	05/06/2050	12/15/2051
Final Easement Termination	12/15/2051	12/15/2051

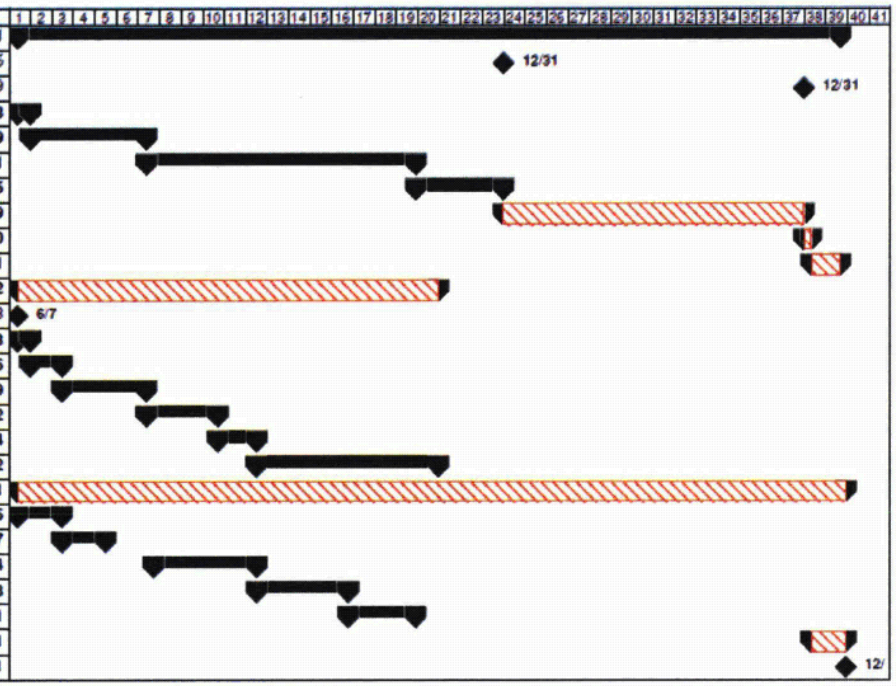

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Table 6-1[3]
Cost and Schedule Summary
(2014 Dollars in Thousands)

Period No.	Period Description	Start	End	Years	Unit 2 Cost	Unit 3 Cost	Total Cost
License Termination (50.75(c))							
Decon Pd 1	Transition to Decommissioning	6/7/2013	12/31/2013	0.56	$25,749	$26,566	$52,315
Decon Pd 2	Decommissioning Planning and Site Modifications	1/1/2014	6/30/2015	1.49	$118,709	$122,430	$241,140
Decon Pd 3	Decommissioning Preparations and Reactor Internals Segmentation	6/30/2015	6/1/2019	3.92	$262,210	$276,799	$539,009
Decon Pd 4	Plant Systems and Large Component Removal	6/1/2019	9/24/2022	3.31	$392,029	$412,475	$804,504
Decon Pd 5	Building Decontamination	9/24/2022	7/13/2024	1.80	$212,447	$216,659	$429,106
Decon Pd 6	License Termination During Demolition	7/13/2024	12/24/2032	8.44	$23,085	$23,085	$46,171
Account Total				**19.52**	**$1,034,230**	**$1,078,016**	**$2,112,246**
Spent Fuel (50.54(bb)) and (72.30)							
SNF Pd 1	Spent Fuel Management Transition	6/7/2013	12/31/2013	0.56	$63,891	$66,105	$129,997
SNF Pd 2	Spent Fuel Transfer to Dry Storage	1/1/2014	6/1/2019	5.41	$344,629	$372,193	$716,822
SNF Pd 3	Dry Storage During Decommissioning - Units 1, 2 and 3	6/1/2019	12/5/2031	12.51	$61,425	$61,425	$122,849
SNF Pd 4	Dry Storage Only - Units 1, 2 and 3	12/5/2031	12/31/2035	4.07	$29,383	$29,383	$58,765
SNF Pd 5	Dry Storage Only - Units 2 and 3	12/31/2035	12/31/2049	14.00	$107,326	$107,326	$214,653
SNF D&D Pd 1	ISFSI License Termination	12/31/2049	5/6/2050	0.34	$1,260	$1,260	$2,520
SNF D&D Pd 2	ISFSI Demolition	5/6/2050	9/8/2051	1.34	$15,295	$15,295	$30,590
Account Total				**38.23**	**$623,209**	**$652,987**	**$1,276,196**
Site Restoration							
SR Pd 1	Transition to Site Restoration	6/7/2013	6/30/2015	2.06	$64,280	$66,210	$130,489
SR Pd 2	Building Demolition During Decommissioning	6/30/2015	7/11/2017	2.03	$13,003	$37,242	$50,245
SR Pd 3	Subsurface Demolition Engineering and Permitting	10/1/2019	7/13/2024	4.78	$15,593	$22,319	$37,912
SR Pd 4	Building Demolition to 3 Feet Below Grade	7/13/2024	10/14/2028	4.25	$124,953	$134,113	$259,066
SR Pd 5	Subgrade Structure Removal Below - 3 Feet	10/14/2028	12/5/2031	3.14	$171,987	$269,560	$441,547
SR Pd 6	Final Site Restoration and Lease Termination	5/6/2050	12/15/2051	1.60	$33,482	$70,064	$103,545
Account Total				**17.86**	**$423,297**	**$599,507**	**$1,022,804**
Grand Total					**$2,080,735**	**$2,330,511**	**$4,411,246**

[3] Rows and columns may not add correctly due to rounding.

Table 6-2
Utility Staff Levels

License Termination – 50.75(c) Utility Staff

Department	Decon Pd 1	Decon Pd 2	Decon Pd 3	Decon Pd 4	Decon Pd 5	Decon Pd 6
Decommissioning	0	21	21	25	18	0
Engineering	0	49	14	14	12	0
Maintenance and Work Control	0	38	10	10	3	0
Operations	0	15	7	7	0	0
Oversight and Nuclear Safety	0	7	2	2	1	0
Radiation Protection and Chemistry	0	27	26	31	26	0
Regulatory and Emergency Planning	0	10	4	4	4	0.5
Safety and Human Performance	0	13	7	7	7	0
Security Admin	0	6	6	6	6	0
Security Guard Force	0	12	12	12	12	0
Site Management and Administration	0	13	13	13	9	1
Period Totals	**0**	**211**	**122**	**131**	**98**	**1.5**

Spent Fuel - 50.54(bb) Utility Staff

Department	SNF Pd 1	SNF Pd 2	SNF Pd 3	SNF Pd 4	SNF Pd 5	SNF D&D Pd 1	SNF D&D Pd 2
Spent Fuel Shipping	0	0	0	2	2	0	0
Decommissioning	0	0	0	0	0	1	1
Engineering	0	1	1	1	1	0	1
Maintenance and Work Control	0	31	0	0	0	0	0
Operations	0	45	1	1	1	0	0
Oversight and Nuclear Safety	0	1	0.25	0.25	0.25	0	0
Radiation Protection and Chemistry	0	6	4	4	4	1	2
Regulatory and Emergency Planning	0	0	0	0	0	1	1
Security Admin	0	14	10	8	8	1	1
Security Guard Force	0	178	35	35	35	5	5
Site Management and Administration	0	0	0	0	0	1	1
Period Total	**0**	**276**	**51.25**	**54.25**	**54.25**	**10**	**12**

Site Restoration - Utility Staff

Department	SR Pd 1	SR Pd 2	SR Pd 3	SR Pd 4	SR Pd 5	SR Pd 6
Decommissioning	0	2	0	5	4	2
Engineering	0	1	0	2	1	0
Maintenance and Work Control	0	1	0	2	2	2
Regulatory and Emergency Planning	0	1	0	0	0	0
Safety and Human Performance	0	1	0	2	1	1
Security Admin	0	0	0	1	1	0
Security Guard Force	0	0	0	5	5	0
Site Management and Administration	0	0	0	4	3	3
Period Totals	**0**	**6**	**0**	**21**	**17**	**8**

Table 6-3
DGC Staff Levels

License Termination – 50.75(c) DGC Staff

Department	Decon Pd 3	Decon Pd 4	Decon Pd 5	Decon Pd 6
Administration	9	17	17	0
Engineering	15	29	14	0
Health Physics	16	73	73	2
Management	3	3	3	0
Quality Assurance	2	5	4	0
Waste Operations	7	16	16	0
Period Totals	**52**	**143**	**127**	**2**

Spent Fuel - 50.54(bb) - DGC Staff

Department	SNF D&D Pd 2
Administration	1
Engineering	2
Health Physics	3
Management	1
Quality Assurance	1
Waste Operations	4
Period Totals	**12**

Site Restoration DGC Staff

Department	SR Pd 1	SR Pd 2	SR Pd 3	SR Pd 4	SR Pd 5	SR Pd 6
Administration	0	0	0	10	5	4
Engineering	0	0	0	13	11	5
Health Physics	0	0	0	3	0	0
Management	0	0	0	2	2	1
Quality Assurance	0	0	0	2	1	0
Waste Operations	0	0	0	11	7	7
Period Totals	**0**	**0**	**0**	**41**	**26**	**17**

Table 6-4
Waste Disposal Volumes
(Cost Excludes Contingency - 2014 Dollars)

Facility and Waste Class	Waste Weight (LBs)	Waste Volume (CF)	Burial Volume (CF)	Packaging Cost	Transportation Cost	Base Burial Cost	Total Disposal Cost
Class B and C Facility							
Class B	1,132,323	6,696	15,199	$1,199,186	$6,433,599	$72,635,570	$80,268,355
Class C	407,380	1,546	8,191	$2,064,309	$26,706,007	$39,142,870	$67,913,186
GTCC	92,861	190	1,882	$196,288	$1,680,000	$38,775,980	$40,652,268
	1,632,564	**8,431**	**25,272**	**$3,459,782**	**$34,819,606**	**$150,554,420**	**$188,833,808**
Energy*Solutions*							
Class A – Debris	200,560,122	3,229,506	3,308,050	$3,804,262	$13,779,286	$211,423,909	$229,007,458
Class A – Oversize	9,967,521	146,943	184,730	$187,314	$784,285	$22,669,947	$23,641,545
Class A – Containerized Waste	1,053,914	12,287	16,303	$397,152	$364,322	$4,112,378	$4,873,851
Class A – Large Component	11,480,200	108,866	136,373	$6,313,568	$69,622,664	$43,582,464	$119,518,696
Class A – Mixed Waste	62,643	3,012	3,012	$67,887	$12,448	$801,226	$881,561
	223,124,400	**3,500,614**	**3,648,469**	**$10,770,182**	**$84,563,005**	**$282,589,924**	**$377,923,111**
Other							
Out of State Class III Landfill	1,909,207,440	25,212,269	29,372,422	$0	$146,326,469	$43,929,750	$190,256,219
Scrap Metal Recycler	184,787,372	377,117	7,391,495	$0	$911,926	$0	$911,926
	2,093,994,812	**25,589,386**	**36,763,917**	**$0**	**$147,238,394**	**$43,929,750**	**$191,168,144**
Grand Total	**2,318,751,776**	**29,098,431**	**40,437,658**	**$14,229,964**	**$266,621,006**	**$477,074,094**	**$757,925,064**

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Appendix A

List of Systems and Structures

SONGS Plant System and Structure List

Common

Type	System Name or Description
Non	Not Used
Struct	Administration Building (K-40/50)
Struct	AWS Building
Struct	Building L-50
Struct	Gunite Slope Protection
Struct	High Flow Make-Up Demineralizer Area
Struct	ISFSI Support Structures
Struct	Maintenance Building 1 (B-43/B-44)
Struct	Maintenance Building 2 (B-49/B-50)
Struct	Maintenance Building 4 (B-64/B-65)
Struct	Maintenance Building 5 (B-62/B-63)
Struct	Mesa Buildings
Struct	Not Used
Struct	Outage Control Center Building
Struct	REMS Staging Pad
Struct	Seawall - Units 2 & 3
Struct	Security Access Building (A-80, 81, 82)
Struct	Service Building (K-10, 20, 30)
Struct	South Security Processing Facility (K-70)
Struct	South Yard Facility Buildings (T-10, 20, 60 and Haz Mat.)
Struct	Staging Warehouse Building
Ess	Auxilary Control Systems - Unit 2
Ess	Fuel Handling Building Systems - Unit 2
Ess	Radwaste Systems - Unit 2
Non	Condenstate Storage Systems - Unit 2
Non	Containment Building Systems - Unit 2
Non	Diesel Generator Systems - Unit 2
Non	Full Flow Areas Systems - Unit 2
Non	Intake Systems - Unit 2
Non	Penetration Building Systems - Unit 2
Non	Safety Equipment Building Systems - Unit 2
Non	Turbine Bldg Equip to 9 ft - Unit 2
Struct	Condensate Storage Area - Unit 2
Struct	Containment Building - Unit 2
Struct	Control Building - Unit 2
Struct	Diesel Generator Building - Unit 2
Struct	Fuel Handling Building - Unit 2
Struct	Full Flow Building - Unit 2
Struct	Intake Structure - Unit 2
Struct	Penetration Building - Unit 2
Struct	Radwaste Building - Unit 2
Struct	Safety Equipment Building - Unit 2
Struct	Tunnels - Unit 2
Struct	Turbine Building - Unit 2
Ess	Auxilary Control Systems - Unit 3
Ess	Fuel Handling Building Systems - Unit 3

SONGS Plant System and Structure List

Unit 3

Type	System Name or Description
Ess	Radwaste Systems - Unit 3
Non	Condenstate Storage Systems - Unit 3
Non	Containment Building Systems - Unit 3
Non	Diesel Generator Systems - Unit 3
Non	Full Flow Areas Systems - Unit 3
Non	Intake Systems - Unit 3
Non	Penetration Building Systems - Unit 3
Non	Safety Equipment Building Systems - Unit 3
Non	Turbine Bldg Equip to 9 ft - Unit 3
Non	Turbine Generator to 63 ft - Unit 3
Struct	Condensate Storage Tank Area - Unit 3
Struct	Containment Building - Unit 3
Struct	Control Building - Unit 3
Struct	Diesel Generator Building - Unit 3
Struct	Fuel Handling Building - Unit 3
Struct	Full Flow Building - Unit 3
Struct	Intake Structure - Unit 3
Struct	Penetration Building - Unit 3
Struct	Radwaste Building - Unit 3
Struct	Safety Equipment Building - Unit 3
Struct	Tunnels - Unit 3
Struct	Turbine Building - Unit 3

Appendix B

Spent Fuel Shipping Schedule

SONGS Unit 2 & Unit 3
Spent Fuel Shipping Schedule
2024 DOE Acceptance

	On-Site Inventory (Beginning of Year)				On-Site Transfers (During Year)		Off-Site Transfers (During Year)			
Year	Units 2 & 3 Fuel Assemblies in Wet Storage	Units 2 & 3 Fuel Assemblies in Dry Storage	Units 2 & 3 Fuel Assemblies in On-Site Storage	Units 2 & 3 Canisters in ISFSI	Unit 2 & 3 Fuel Assemblies Transferred to ISFSI	Unit 2 & 3 Fuel Canisters Transferred to ISFSI	Unit 2 Assemblies Transferred to DOE	Unit 3 Assemblies Transferred to DOE	Units 2 & 3 Assemblies Transferred to DOE	Units 2 & 3 Canisters Transferred to DOE
2014	2668	792	3460	33	0	0	0	0	0	0
2015	2668	792	3460	33	0	0	0	0	0	0
2016	2668	792	3460	33	0	0	0	0	0	0
2017	2668	792	3460	33	768	24	0	0	0	0
2018	1900	1560	3460	57	1,536	48	0	0	0	0
2019	364	3096	3460	105	364	13	0	0	0	0
2020	0	3460	3460	118	0	0	0	0	0	0
2021	0	3460	3460	118	0	0	0	0	0	0
2022	0	3460	3460	118	0	0	0	0	0	0
2023	0	3460	3460	118	0	0	0	0	0	0
2024	0	3460	3460	118	0	0	0	0	0	0
2025	0	3460	3460	118	0	0	0	0	0	0
2026	0	3460	3460	118	0	0	0	0	0	0
2027	0	3460	3460	118	0	0	0	0	0	0
2028	0	3460	3460	118	0	0	0	0	0	0
2029	0	3460	3460	118	0	0	0	0	0	0
2030	0	3460	3460	118	0	0	48	48	96	4
2031	0	3364	3364	114	0	0	192	96	288	12
2032	0	3076	3076	102	0	0	120	120	240	10
2033	0	2836	2836	92	0	0	0	96	96	4
2034	0	2740	2740	88	0	0	112	120	232	8
2035	0	2508	2508	80	0	0	96	96	192	6
2036	0	2316	2316	74	0	0	128	96	224	7
2037	0	2092	2092	67	0	0	0	0	0	0
2038	0	2092	2092	67	0	0	96	128	224	7
2039	0	1868	1868	60	0	0	96	96	192	6
2040	0	1676	1676	54	0	0	96	96	192	6
2041	0	1484	1484	48	0	0	0	0	0	0
2042	0	1484	1484	48	0	0	96	96	192	6
2043	0	1292	1292	42	0	0	96	96	192	6
2044	0	1100	1100	36	0	0	96	96	192	6
2045	0	908	908	30	0	0	128	96	224	7
2046	0	684	684	23	0	0	96	128	224	7
2047	0	460	460	16	0	0	96	230	326	11
2048	0	134	134	5	0	0	0	0	0	0
2049	0	134	134	5	0	0	134	0	134	5
2050	0	0	0	0	0	0	0	0	0	0

Appendix C

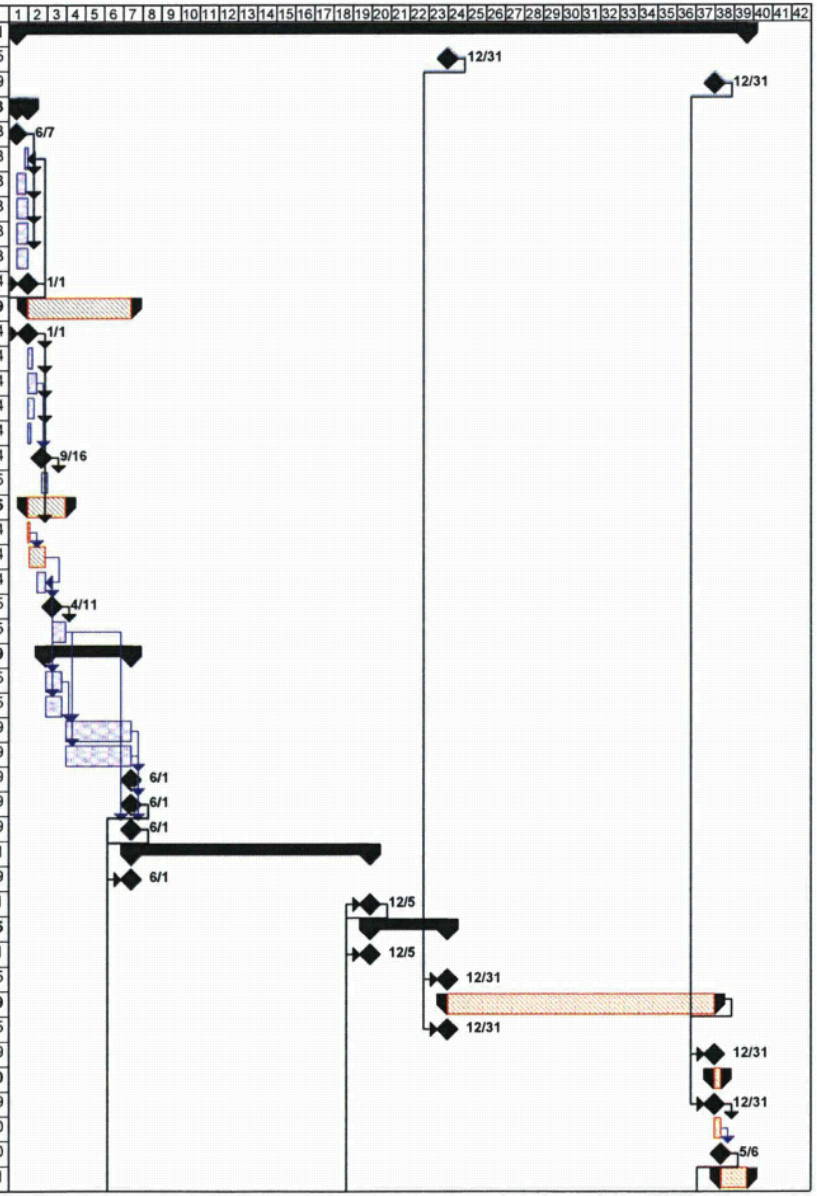
Detailed Project Schedule

SONGS 2 & 3

Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
1	**Post-Shutdown Spent Fuel Management**	**9982 days**	**06/07/2013**	**09/08/2051**
2	Spent Fuel Shipping Complete - Unit 1	0 days	12/31/2035	12/31/2035
3	Spent Fuel Shipping Complete - Units 2 & 3	0 days	12/31/2049	12/31/2049
4	**SNF Pd 1 - Spent Fuel Management Transition**	**149 days**	**06/07/2013**	**12/31/2013**
5	SNF Pd 1 Begins	0 days	06/07/2013	06/07/2013
6	Security Enhancements	45 days	10/31/2013	12/31/2013
7	Design and Fabricate Spent Fuel Canisters	120 days	06/07/2013	11/21/2013
8	Post Fukushima Modifications - Unit 2	148 days	06/07/2013	12/31/2013
9	Post Fukushima Modifications - Unit 3	148 days	06/07/2013	12/31/2013
10	Cyber Security Modifications	148 days	06/07/2013	12/31/2013
11	SNF Pd 1 Ends	0 days	01/01/2014	01/01/2014
12	**SNF Pd 2 - Spent Fuel Transfer to Dry Storage**	**1413 days**	**1/1/2014**	**06/01/2019**
13	SNF Pd 2 Begins	0 days	01/01/2014	01/01/2014
14	Security Enhancements	60 days	01/02/2014	03/26/2014
15	Prepare Irradiated Fuel Management Plan	118 days	01/02/2014	06/14/2014
16	Decay Heat Analysis	85 days	01/02/2014	04/30/2014
17	Zirconium Fire and Shine Analysis	42 days	01/02/2014	02/28/2014
18	Issue Irradiated Fuel Management Plan	0 days	09/16/2014	09/16/2014
19	NRC Review of Irradiated Fuel Management Plan	82 days	09/17/2014	01/08/2015
20	**ISFSI Expansion**	**513 days**	**01/02/2014**	**12/19/2015**
21	Select Dry Storage System Canister Design and Vendor	30 days	01/02/2014	02/12/2014
22	ISFSI Pad Study	220 days	02/03/2014	12/06/2014
23	Design ISFSI Expansion	120 days	06/24/2014	12/06/2014
24	ISFSI Permit Approved By California Coastal Commission	0 days	04/11/2015	04/11/2015
25	Construct ISFSI Expansion	180 days	04/14/2015	12/19/2015
26	**Canister Purchase, Fabrication and Fuel Tranfer**	**1170 days**	**12/09/2014**	**06/01/2019**
27	Purchase Spent Fuel Canisters and AHSMs - Unit 2	220 days	12/09/2014	10/10/2015
28	Purchase Spent Fuel Canisters and AHSMs - Unit 3	220 days	12/09/2014	10/10/2015
29	Load Spent Fuel Canisters and Transfer to ISFSI - Unit 2	900 days	12/22/2015	06/01/2019
30	Load Spent Fuel Canisters and Transfer to ISFSI - Unit 3	900 days	12/22/2015	06/01/2019
31	Unit 2 Spent Fuel Pool Empty	0 days	06/01/2019	06/01/2019
32	Unit 3 Spent Fuel Pool Empty	0 days	06/01/2019	06/01/2019
33	SNF Pd 2 Ends	0 days	06/01/2019	06/01/2019
34	**SNF Pd 3 - Dry Storage During Decommissioning - Units 1, 2 and 3**	**3265 days**	**06/01/2019**	**12/05/2031**
35	SNF Pd 3 Begins	0 days	06/01/2019	06/01/2019
36	SNF Pd 3 Ends	0 days	12/05/2031	12/05/2031
37	**SNF Pd 4 - Dry Storage Only - Units 1, 2 and 3**	**1061 days**	**12/05/2031**	**12/31/2035**
38	SNF Pd 4 Begins	0 days	12/05/2031	12/05/2031
39	SNF Pd 4 Ends	0 days	12/31/2035	12/31/2035
40	**SNF Pd 5 - Dry Storage Only - Units 2 and 3**	**3654 days**	**12/31/2035**	**12/31/2049**
41	SNF Pd 5 Begins	0 days	12/31/2035	12/31/2035
42	SNF Pd 5 Ends	0 days	12/31/2049	12/31/2049
43	**SNF D&D Pd 1 - ISFSI D&D Planning**	**90 days**	**12/31/2049**	**05/06/2050**
44	SNF D&D Pd 1 Begins	0 days	12/31/2049	12/31/2049
45	Preparation and NRC Review of License Termination Plan	90 days	01/01/2050	05/06/2050
46	SNF D&D Pd 1 Ends	0 days	05/06/2050	05/06/2050
47	**SNF D&D Pd 2 - ISFSI D&D**	**350 days**	**05/06/2050**	**09/08/2051**



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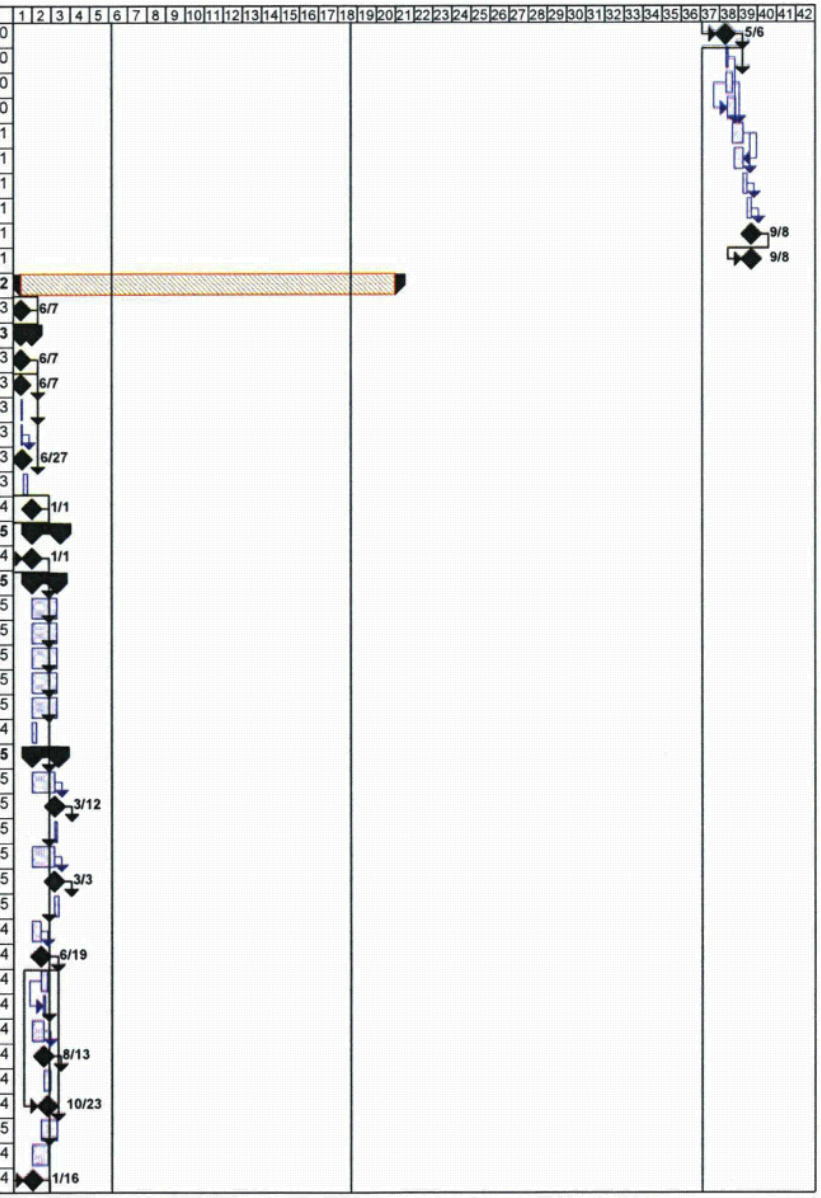
Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
48	SNF D&D Pd 2 Begins	0 days	05/06/2050	05/06/2050
49	Install GARDIAN Bulk Assay System	30 days	05/07/2050	06/17/2050
50	Decon AHSMs	90 days	05/07/2050	09/09/2050
51	Final Status Survey of ISFSI	120 days	05/28/2050	11/11/2050
52	Clean Demolition of ISFSI AHSMs and Pad	145 days	09/10/2050	03/31/2051
53	Clean Demolition of ISFSI Support Structures	120 days	10/15/2050	03/31/2051
54	Restore ISFSI Site	55 days	04/01/2051	06/16/2051
55	Preparation of Final Report on Decommissioning and NRC Review	60 days	06/17/2051	09/08/2051
56	SNF D&D Pd 2 Ends - License Termination Complete	0 days	09/08/2051	09/08/2051
57	Post-Shutdown Spent Fuel Management Complete	0 days	09/08/2051	09/08/2051
58	**Part 50 License Termination**	**5102 days**	**06/07/2013**	**12/24/2032**
59	Announcement of Cessation of Operations (June 7, 2013)	0 days	06/07/2013	06/07/2013
60	**Decon Pd 1 - Transition to Decommissioning**	**149 days**	**06/07/2013**	**12/31/2013**
61	Decon Pd 1 Begins	0 days	06/07/2013	06/07/2013
62	Certification of Permanent Cessation Submitted to NRC (June 12, 2013)	0 days	06/07/2013	06/07/2013
63	Defuel Unit 3 Reactor	15 days	06/07/2013	06/27/2013
64	Defuel Unit 2 Reactor	15 days	06/07/2013	06/27/2013
65	Notification of Permanent Fuel Removal (July 23, 2013)	0 days	06/27/2013	06/27/2013
66	Disposition of Legacy Wastes	60 days	07/19/2013	10/10/2013
67	Decon Pd 1 Ends	0 days	01/01/2014	01/01/2014
68	**Decon Pd 2 - Decommissioning Planning and Site Modifications**	**389 days**	**1/1/2014**	**06/30/2015**
69	Decon Pd 2 Begins	0 wks	01/01/2014	01/01/2014
70	**Preparation of Decommissioning License Documents**	**340 days**	**01/02/2014**	**04/22/2015**
71	Develop Certified Fuel Handler Program	340 days	01/02/2014	04/22/2015
72	Prepare Post-Shutdown QA Plan	340 days	01/02/2014	04/22/2015
73	Prepare Post-Shutdown Security Plan	340 days	01/02/2014	04/22/2015
74	Prepare Post-Shutdown Fire Protection Plan	340 days	01/02/2014	04/22/2015
75	Prepare Defueled Radiation Protection Manual	340 days	01/02/2014	04/22/2015
76	Prepare Preliminary Defueled Technical Specifications	63 days	01/02/2014	03/29/2014
77	**NRC Deliverables**	**364 days**	**01/02/2014**	**05/26/2015**
78	Prepare Defueled Safety Analysis Report (DSAR)	311 days	01/02/2014	03/12/2015
79	Submit DSAR to NRC	0 days	03/12/2015	03/12/2015
80	Implement Technical Specification Modifications	30 days	03/13/2015	04/23/2015
81	Prepare Post-Shutdown Emergency Preparedness Plan	304 days	01/02/2014	03/03/2015
82	Submit Emergency Plan to NRC	0 days	03/03/2015	03/03/2015
83	NRC Review of Emergency Plan	60 days	03/04/2015	05/26/2015
84	Prepare Post-Shutdown Decommissioning Activities Report (PSDAR)	121 days	01/02/2014	06/19/2014
85	Submit PSDAR to NRC	0 days	06/19/2014	06/19/2014
86	NRC Review of PSDAR	90 days	06/20/2014	10/23/2014
87	Public Meeting on PSDAR	30 days	08/01/2014	09/11/2014
88	Prepare Decommissioning Cost Estimate (DCE)	160 days	01/02/2014	08/13/2014
89	Submit DCE to NRC	0 days	08/13/2014	08/13/2014
90	NRC Review of Decommissioning Cost Estimate	90 days	08/14/2014	12/17/2014
91	Commencement of Major Decommisisoning Activities Allowable	0 days	10/23/2014	10/23/2014
92	Respond to NRC quesitons on PSDAR	220 days	06/20/2014	04/23/2015
93	Disposition of Legacy Wastes	220 days	01/02/2014	11/05/2014
94	Contract Award for Historic Site Assessment and Site Characterization	0 wks	01/16/2014	01/16/2014



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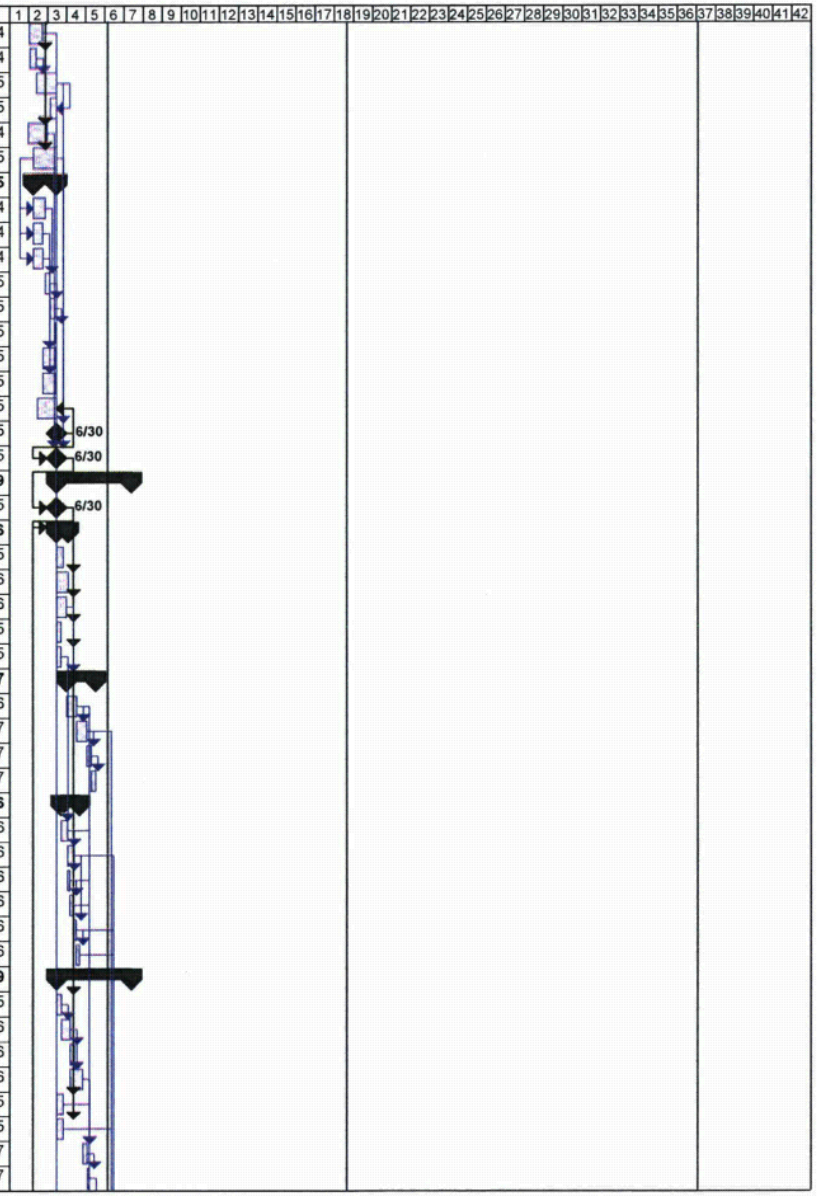
Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
95	Perform Historic Site Assessment and Site Characterization	180 days	01/17/2014	09/25/2014
96	Planning and Design For Cold and Dark	90 days	02/01/2014	06/06/2014
97	Implement Cold and Dark (Repower Site)	275 days	06/07/2014	06/26/2015
98	Install 12kV Service Line to Power Temporary Power Ring	90 days	02/21/2015	06/26/2015
99	Drain and De-Energize Non-Essential Systems (DEC Process)	260 days	01/02/2014	12/31/2014
100	Select Decommissioning General Contractor (DGC)	318 days	04/11/2014	06/30/2015
101	**Spent Fuel Pool Isolation**	**318 days**	**04/11/2014**	**06/30/2015**
102	Design Spent Fuel Pool Support System Modifications	160 days	04/11/2014	11/20/2014
103	Design Control Room Relocation	125 days	04/11/2014	10/02/2014
104	Design Spent Fuel Security System Modifications	130 days	04/11/2014	10/09/2014
105	Install Spent Fuel Pool System Modifications - Unit 2	66 days	11/21/2014	02/20/2015
106	Install Spent Fuel Pool System Modifications - Unit 3	66 days	02/21/2015	05/23/2015
107	Spent Fuel Pool Island System Training	10 days	05/26/2015	06/06/2015
108	Implement Control Room Modifications	185 days	10/03/2014	06/18/2015
109	Implement Spent Fuel Pool Security Modifications	180 days	10/10/2014	06/18/2015
110	Transition Project Modifictations	262 days	06/28/2014	06/30/2015
111	DGC Contract Award	0 days	06/30/2015	06/30/2015
112	Decon Pd 2 Ends	0 wks	06/30/2015	06/30/2015
113	**Decon Pd 3 - Decommissioning Preparations and Reactor Internals Segmenta**	**1024 days**	**06/30/2015**	**06/01/2019**
114	Decon Pd 3 Begins	0 days	06/30/2015	06/30/2015
115	**DGC Mobilization and Planning**	**160 days**	**07/01/2015**	**02/09/2016**
116	Prepare Integrated Work Sequence and Schedule for Decommissioning	90 days	07/01/2015	11/03/2015
117	Prepare Detailed Work Procedures for Decommissioning	160 days	07/01/2015	02/09/2016
118	Planning and Design of Primary System Decontamination	135 days	07/01/2015	01/05/2016
119	Planning and Design of Infrastructure Improvements	60 days	07/01/2015	09/22/2015
120	Design Containment Access Modifications	60 days	07/01/2015	09/22/2015
121	**System Decon**	**400 days**	**01/06/2016**	**07/18/2017**
122	Perform Primary System Decon- Unit 2	140 days	01/06/2016	07/19/2016
123	Perform Primary System Decon- Unit 3	140 days	07/20/2016	01/31/2017
124	Hot Spot Decontamination - Unit 2	60 days	02/01/2017	04/25/2017
125	Hot Spot Decontamination - Unit 3	60 days	04/26/2017	07/18/2017
126	**Rx Internals Removal Preparations**	**255 days**	**09/23/2015**	**09/13/2016**
127	Modify Containment Access- Unit 2	90 days	09/23/2015	01/26/2016
128	Modify Containment Access- Unit 3	90 days	01/27/2016	05/31/2016
129	Remove and Dispose of Missle Shields - Unit 2	30 days	01/27/2016	03/08/2016
130	Remove and Dispose of Reactor Head - Unit 2	45 days	03/09/2016	05/10/2016
131	Remove and Dispose of Missle Shields - Unit 3	30 days	06/01/2016	07/12/2016
132	Remove and Dispose of Reactor Head - Unit 3	45 days	07/13/2016	09/13/2016
133	**Reactor Internals Segmentation Planning and Implementation**	**1020 days**	**07/01/2015**	**05/28/2019**
134	Finalize Residual Radiation Inventory (Rx Vessel & Internals)	65 days	07/01/2015	09/29/2015
135	Prepare Activity Specification for Rx Vessel and Internals Segmentation	120 days	09/30/2015	03/15/2016
136	Select Shipping Casks and Obtain Shipping Permits	60 days	03/16/2016	06/07/2016
137	Design, Specify, and Procure Special Items and Materials	175 days	03/16/2016	11/15/2016
138	Purchase Dry Storage Modules for GTCC Waste - Unit 2	90 days	07/01/2015	11/03/2015
139	Purchase Dry Storage Modules for GTCC Waste - Unit 3	90 days	07/01/2015	11/03/2015
140	Test Special Cutting and Handling Equipment and Train Operators	60 days	11/16/2016	02/07/2017
141	Finalize Internals and Vessel Segmenting Details - Unit 2	30 days	02/08/2017	03/21/2017



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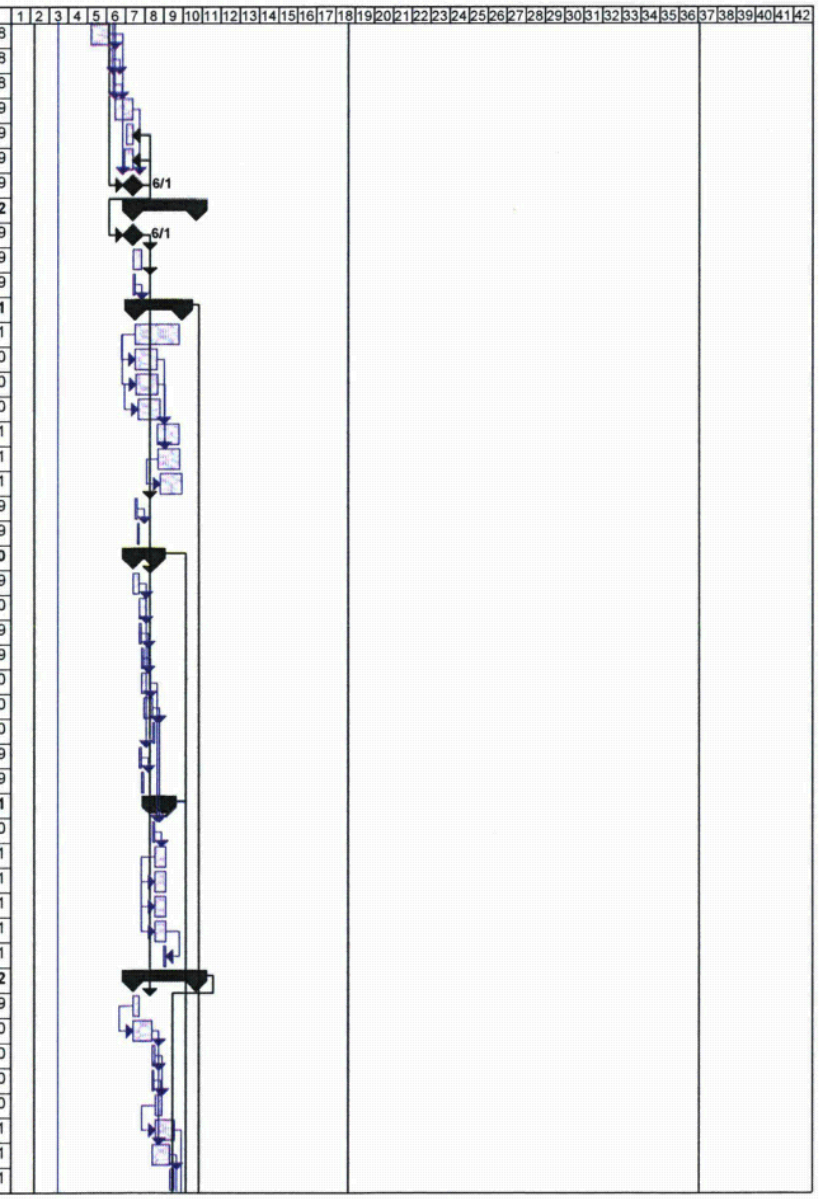
Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
142	Segment, Package and Dispose of Reactor Internals - Unit 2	240 days	03/22/2017	02/20/2018
143	Transfer Internals Segmentation Equipment to Unit 3	60 days	02/21/2018	05/15/2018
144	Finalize Internals and Vessel Segmenting Details - Unit 3	30 days	05/16/2018	06/26/2018
145	Segment, Package and Dispose of Reactor Internals - Unit 3	240 days	06/27/2018	05/28/2019
146	Construct new change rooms, hot laundry, in-plant laydown areas	90 days	01/29/2019	06/01/2019
147	Procure Non-Engineered Standard Equipment	120 days	12/18/2018	06/01/2019
148	Decon Pd 3 Ends	0 wks	06/01/2019	06/01/2019
149	**Decon Pd 4 - Plant Systems and Large Component Removal**	**865 days**	**06/01/2019**	**09/24/2022**
150	Decon Pd 4 Begins	0 days	06/01/2019	06/01/2019
151	Upgrade Rail Spur	120 days	06/04/2019	11/16/2019
152	Install GARDIAN Bulk Assay System	30 days	06/04/2019	07/13/2019
153	**Non Essential System Removal**	**640 days**	**07/16/2019**	**12/25/2021**
154	Scaffolding for Non-Essential System Removal	120 wks	07/16/2019	10/30/2021
155	Asbestos Abatement for Non-Essential Systems Removal - Unit 2	60 wks	07/16/2019	09/05/2020
156	Lead Abatement for Non-Essential Systems Removal - Unit 2	60 wks	07/30/2019	09/19/2020
157	Remove, Package and Dispose of Non-Essential Systems - Unit 2	60 wks	09/10/2019	10/31/2020
158	Asbestos Abatement for Non-Essential Systems - Unit 3	60 wks	09/08/2020	10/30/2021
159	Lead Abatement for Non-Essential Systems - Unit 3	60 wks	09/22/2020	11/13/2021
160	Remove, Package and Dispose of Non-Essential Systems - Unit 3	60 wks	11/03/2020	12/25/2021
161	Remove Underground Diesel Tank - Unit 2	30 days	07/16/2019	08/24/2019
162	Remove Underground Diesel Tank - Unit 3	30 days	08/27/2019	10/05/2019
163	**Fuel Pool Closure**	**300 days**	**06/04/2019**	**07/25/2020**
164	Remove and Dispose of Spent Fuel Storage Racks - Unit 2	90 days	06/04/2019	10/05/2019
165	Remove and Dispose of Spent Fuel Storage Racks - Unit 3	90 days	10/08/2019	02/08/2020
166	Remove and Dispose of Legacy Class B and C Waste - Unit 2	30 days	10/08/2019	11/16/2019
167	Remove and Dispose of Legacy Class B and C Waste - Unit 3	30 days	11/19/2019	12/28/2019
168	Drain Spent Fuel Pool and Process Liquid Waste - Unit 2	24 wks	11/19/2019	05/02/2020
169	Drain Spent Fuel Pool and Process Liquid Waste - Unit 3	24 wks	12/31/2019	06/13/2020
170	Segment, Package and Dispose of Spent Fuel Pool Island Equipment	30 days	06/16/2020	07/25/2020
171	Segment and Dispose of Fuel Pool Bridge Crane - Unit 2	30 days	10/08/2019	11/16/2019
172	Segment and Dispose of Fuel Pool Bridge Crane - Unit 3	30 days	11/19/2019	12/28/2019
173	**Essential Systems Removal**	**180 days**	**06/16/2020**	**02/20/2021**
174	Flush and Drain Essential Systems Following Fuel Pool Closure	30 days	06/16/2020	07/25/2020
175	Scaffolding for Essential System Removal	30 wks	07/28/2020	02/20/2021
176	Asbestos Abatement for Essential Systems	30 wks	07/28/2020	02/20/2021
177	Lead Abatement for Essential Systems Removal	30 wks	07/28/2020	02/20/2021
178	Remove, Package and Dispose of Essential Systems	30 wks	07/28/2020	02/20/2021
179	Removal and Disposal of Spent Resins, Filter Media and Tank Sludge	30 days	01/12/2021	02/20/2021
180	**Large Component Removal**	**865 days**	**06/04/2019**	**09/24/2022**
181	Reactor Vessel Insulation Removal and Disposal - Unit 2	90 days	06/04/2019	10/05/2019
182	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 2	260 days	06/04/2019	05/30/2020
183	Transfer Rx Vessel Segmentation Equipment to Unit 3	45 days	06/02/2020	08/01/2020
184	Procure Replacement Non-Engineered Standard Equipment	30 days	06/02/2020	07/11/2020
185	Reactor Vessel Insulation Removal and Disposal - Unit 3	90 days	08/04/2020	12/05/2020
186	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 3	260 days	08/04/2020	07/31/2021
187	Remove and Dispose of Steam Generators - Unit 2	240 days	06/02/2020	05/01/2021
188	Remove and Dispose of Pressurizer - Unit 2	60 days	05/04/2021	07/24/2021



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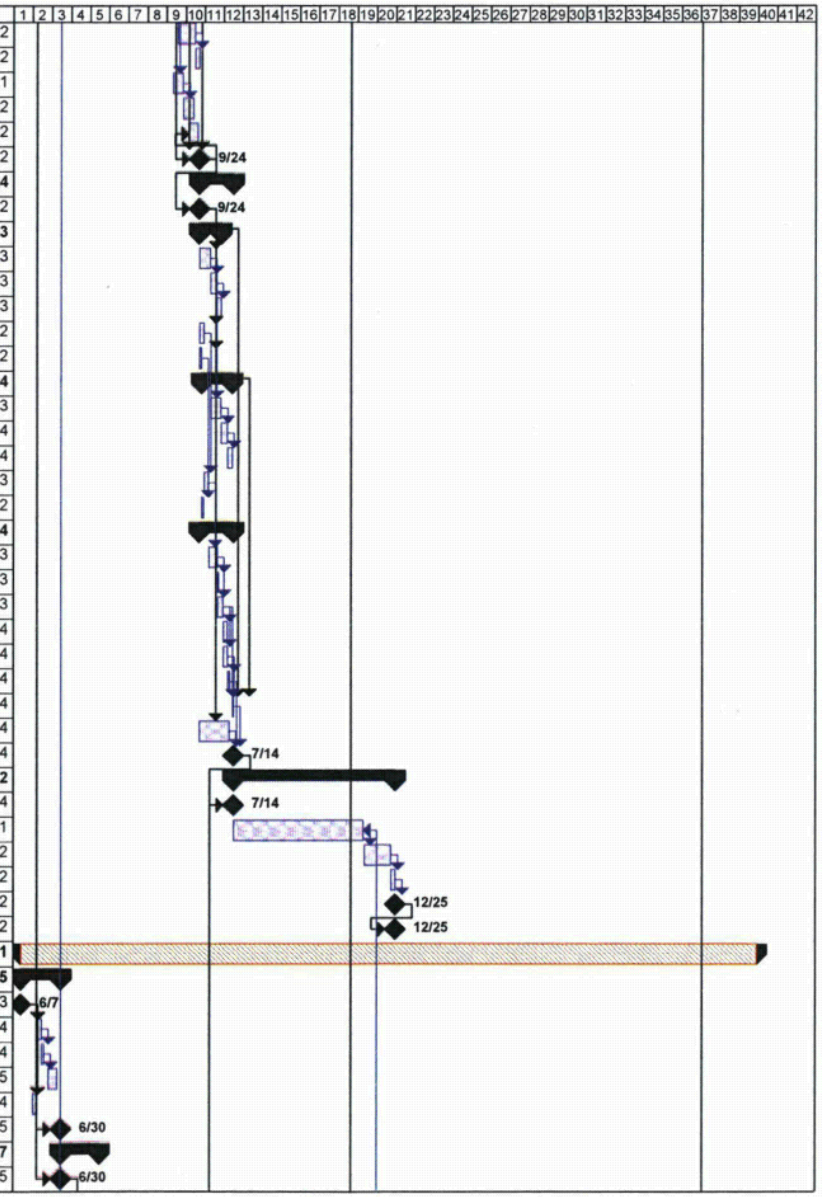
ID	Task Name	Duration	Start	Finish
189	Remove and Dispose of Steam Generators - Unit 3	240 days	08/03/2021	07/02/2022
190	Remove and Dispose of Pressurizer - Unit 3	60 days	07/05/2022	09/24/2022
191	Remove and Dispose of Turbine Gantry Crane - Unit 2	140 days	05/04/2021	11/13/2021
192	Remove and Dispose of Turbine Gantry Crane - Unit 3	140 days	11/16/2021	05/28/2022
193	Prepare License Termination Plan	26 wks	03/01/2022	08/27/2022
194	Decon Pd 4 Ends	0 days	09/24/2022	09/24/2022
195	**Decon Pd 5 - Building Decontamination**	**470 days**	**09/24/2022**	**07/13/2024**
196	Decon Pd 5 Begins	0 days	09/24/2022	09/24/2022
197	**Unit 3**	**305 days**	**09/27/2022**	**11/25/2023**
198	Decon Containment Building - Unit 3	150 days	09/27/2022	04/22/2023
199	Decon Penetration Building - Unit 3	85 days	04/25/2023	08/19/2023
200	Decon Safety Equipment and MSIV Building - Unit 3	70 days	08/22/2023	11/25/2023
201	Decon Fuel Handling Building - Unit 3	65 days	09/27/2022	12/24/2022
202	Decon Turbine Building - Unit 3	30 days	09/27/2022	11/05/2022
203	**Unit 2**	**425 days**	**11/08/2022**	**06/22/2024**
204	Decon Containment Building - Unit 2	150 days	04/25/2023	11/18/2023
205	Decon Penetration Building - Unit 2	85 days	11/21/2023	03/16/2024
206	Decon Safety Equipment and MSIV Building - Unit 2	70 days	03/19/2024	06/22/2024
207	Decon Fuel Handling Building - Unit 2	65 days	12/27/2022	03/25/2023
208	Decon Turbine Building - Unit 2	30 days	11/08/2022	12/17/2022
209	**Common**	**470 days**	**09/27/2022**	**07/13/2024**
210	Decon Auxiliary Radwaste Building - Common	120 days	03/28/2023	09/09/2023
211	Decon Auxiliary Control Building - Common	20 days	09/12/2023	10/07/2023
212	Decon Condensate Area and Tunnels - Units 2 and 3	80 days	09/12/2023	12/30/2023
213	Excavate, Remove and Dispose of Yard Area Drains	60 days	01/02/2024	03/23/2024
214	Remove and Dispose of Contaminated Sumps, Trenches and Pavement	60 days	01/02/2024	03/23/2024
215	Remove and Dispose of Radiologically Contaminated Soil	30 days	03/26/2024	05/04/2024
216	Dispose of Contaminated Decon Equipment and Tooling	15 days	06/25/2024	07/13/2024
217	Radiological Survey of Structures During Decon	410 days	09/27/2022	04/20/2024
218	Decon Pd 5 Ends	0 days	07/13/2024	07/13/2024
219	**Decon Pd 6 - License Termination During Demolition**	**2206 days**	**07/13/2024**	**12/24/2032**
220	Decon Pd 6 Begins	0 days	07/13/2024	07/13/2024
221	Final Status Survey	1771 days	07/13/2024	04/25/2031
222	ORISE Verification and NRC Approval	18 mons	05/17/2031	10/01/2032
223	Prepare Final Report of Dismantling Program	60 days	10/02/2032	12/24/2032
224	Decon Complete - Partial License Termination	0 days	12/24/2032	12/24/2032
225	Decon Pd 6 Ends	0 days	12/24/2032	12/24/2032
226	**Site Restoration**	**10052 days**	**06/07/2013**	**12/15/2051**
227	**SR Pd 1 - Transition to Site Restoration**	**538 days**	**06/07/2013**	**06/30/2015**
228	SR Pd 1 Begins	0 days	06/07/2013	06/07/2013
229	Mesa Site Phase I and II Site Assessment	60 days	04/11/2014	07/03/2014
230	Disposition Hazardous Waste from Mesa Site	30 days	07/04/2014	08/14/2014
231	Mesa Site Characterization Survey	120 days	11/07/2014	04/23/2015
232	Fuel Cancellation Expense	60 days	01/21/2014	04/12/2014
233	SR Pd 1 Ends	0 days	06/30/2015	06/30/2015
234	**SR Pd 2 - Building Demolition During Decommissioning**	**530 days**	**06/30/2015**	**07/11/2017**
235	SR Pd 2 Begins	0 days	06/30/2015	06/30/2015



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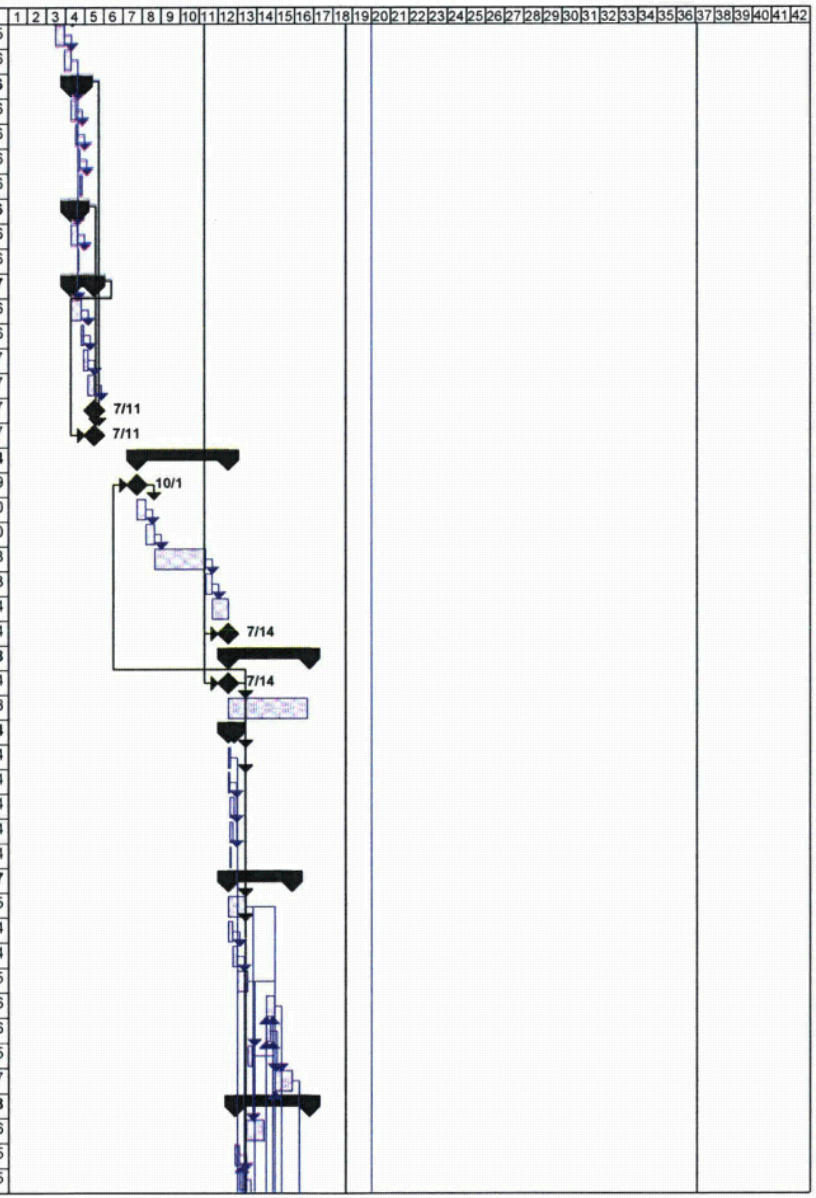
ID	Task Name	Duration	Start	Finish
236	Prepare Site Restoration Demolition Plan and Schedule	120 days	07/01/2015	12/15/2015
237	Obtain Required Permits For Mesa, South Access and South Yard	90 days	12/16/2015	04/19/2016
238	**South Access for Decommissioning**	**150 days**	**04/20/2016**	**11/15/2016**
239	Demolish Service Building (K-10, 20, 30)	60 days	04/20/2016	07/12/2016
240	Demolish South Security Processing Facility (K-70)	30 days	07/13/2016	08/23/2016
241	Demolish Staging Warehouse	30 days	08/24/2016	10/04/2016
242	Demolish Administration Building (K-40/50)	30 days	10/05/2016	11/15/2016
243	**South Yard Facility**	**105 days**	**04/20/2016**	**09/13/2016**
244	Demolish South Yard Area Buildings T-10, 20, 60 and Haz Mat.	90 days	04/20/2016	08/23/2016
245	Demolish REMS Staging Pad	15 days	08/24/2016	09/13/2016
246	**Mesa**	**320 days**	**04/20/2016**	**07/11/2017**
247	Demolish Mesa Buildings	140 days	04/20/2016	11/01/2016
248	Remove Underground Fuel Storage Tanks	30 days	11/02/2016	12/13/2016
249	Demolish Mesa Roads and Parking Lots	60 days	12/14/2016	03/07/2017
250	Finish Grading and Re-vegetate Mesa Site	90 days	03/08/2017	07/11/2017
251	Mesa Area Cleared for Easement Termination	0 days	07/11/2017	07/11/2017
252	SR Pd 2 Ends	0 days	07/11/2017	07/11/2017
253	**SR Pd 3 - Subsurface Demolition Engineering and Permitting**	**1250 days**	**10/01/2019**	**07/13/2024**
254	SR Pd 3 Begins	0 days	10/01/2019	10/01/2019
255	Hydrogeologic Investigation and Outfall Conduit Survey	120 days	10/01/2019	03/14/2020
256	Subsurface Structure Removal Engineering Planning and Design	120 days	03/17/2020	08/29/2020
257	Environmental Impacts Analyses for Lease Termination Activities	700 days	09/01/2020	05/06/2023
258	Final Site Grading and Shoreline Protection Engineering Planning and Design	90 days	05/09/2023	09/09/2023
259	Obtain Required Permits and Approvals	220 days	09/12/2023	07/13/2024
260	SR Pd 3 Ends	0 days	07/13/2024	07/13/2024
261	**SR Pd 4 - Building Demolition to 3 Feet Below Grade**	**1110 days**	**07/13/2024**	**10/14/2028**
262	SR Pd 4 Begins	0 days	07/13/2024	07/13/2024
263	Procure Building Demolition Equipment	1080 days	07/16/2024	09/02/2028
264	**Demolition Preparations**	**80 days**	**07/16/2024**	**11/02/2024**
265	Install Temporary Structures	30 days	07/16/2024	08/24/2024
266	Install Erosion and Sediment Controls	20 days	07/16/2024	08/10/2024
267	Remove Cathodic Protection Trench	60 days	08/13/2024	11/02/2024
268	Remove Protected Area Security Fencing	45 days	08/13/2024	10/12/2024
269	Remove Protected Area Pavement	20 days	08/13/2024	09/07/2024
270	**Unit 3**	**870 days**	**07/16/2024**	**11/13/2027**
271	Detension and Remove Unit 3 Containment Builidng Tendons	240 days	07/16/2024	06/14/2025
272	Demolish Diesel Generator Building - Unit 3	60 days	07/16/2024	10/05/2024
273	Demolish Condensate Building and Transformer Pads - Unit 3	60 days	10/08/2024	12/28/2024
274	Demolish Full Flow Area and Turbine Building - Unit 3	140 days	12/31/2024	07/12/2025
275	Demolish Unit 3 Fuel Handling Building to 3-Feet Below Grade	120 days	06/30/2026	12/12/2026
276	Demolish Penetration Building - Unit 3	60 days	06/30/2026	09/19/2026
277	Demolish Safety Equipmentand MSIV Building - Unit 3	60 days	07/15/2025	10/04/2025
278	Demolish Unit 3 Containment Building to 3-Feet Below Grade	240 days	12/15/2026	11/13/2027
279	**Unit 2**	**1020 days**	**11/19/2024**	**10/14/2028**
280	Detension and Remove Unit 2 Containment Builidng Tendons	240 days	06/17/2025	05/16/2026
281	Demolish Diesel Generator Building - Unit 2	60 days	11/19/2024	02/08/2025
282	Demolish Condensate Building and Transformer Pads - Unit 2	60 days	02/11/2025	05/03/2025

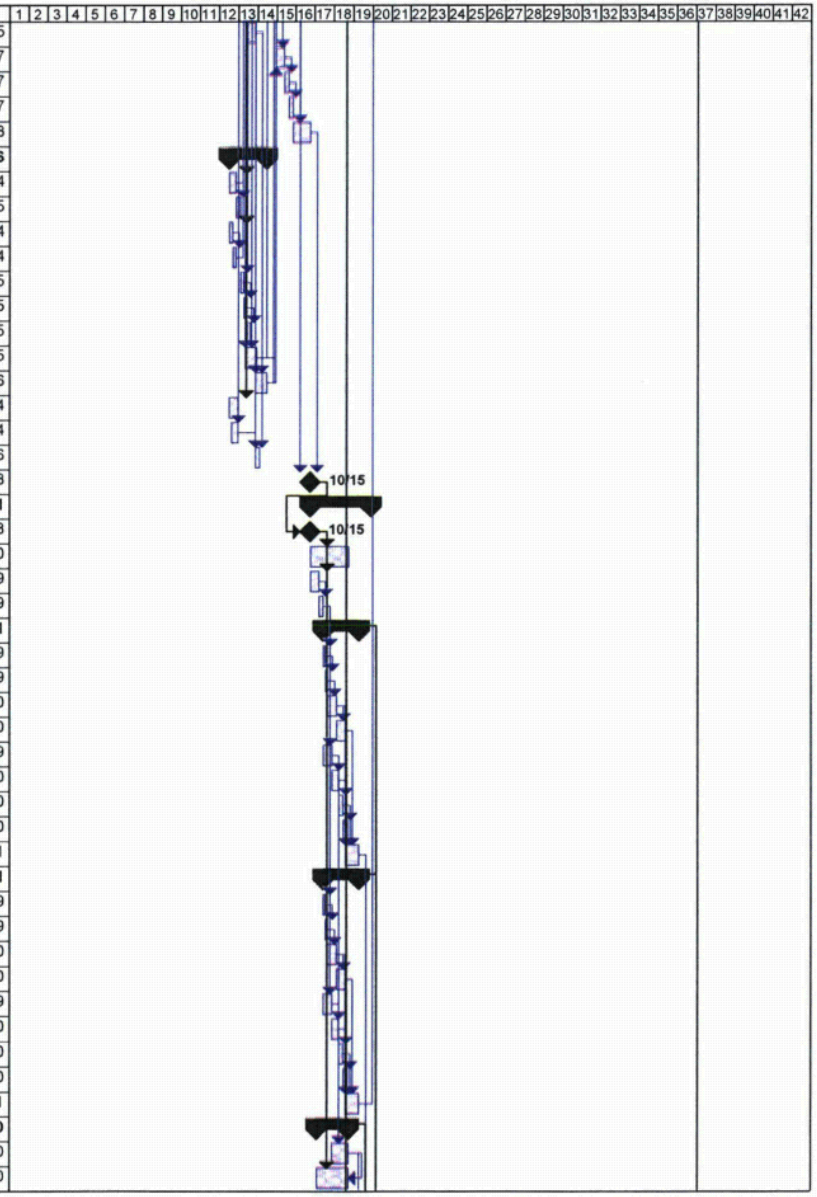


SONGS 2 & 3

Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
283	Demolish Full Flow Area and Turbine Building - Unit 2	140 days	05/06/2025	11/15/2025
284	Demolish Unit 2 Fuel Handling Building to 3-Feet Below Grade	120 days	12/15/2026	05/29/2027
285	Demolish Penetration Building - Unit 2	60 days	06/01/2027	08/21/2027
286	Demolish Safety Equipment and MSIV Building - Unit 2	60 days	08/24/2027	11/13/2027
287	Demolish Unit 2 Containment Building to 3-Feet Below Grade	240 days	11/16/2027	10/14/2028
288	**Common**	**510 days**	**07/16/2024**	**06/27/2026**
289	Demolish AWS Building	90 days	07/16/2024	11/16/2024
290	Demolish Building L-50	60 days	11/19/2024	02/08/2025
291	Demolish Building B-64/B-65	45 days	07/16/2024	09/14/2024
292	Demolish Building B-62/B-63	45 days	09/17/2024	11/16/2024
293	Demolish Outage Control Center	45 days	02/11/2025	04/12/2025
294	Demolish Building B-49/B-50	45 days	04/15/2025	06/14/2025
295	Demolish Building B-43/B-44	45 days	06/17/2025	08/16/2025
296	Demolish Auxiliary Radwaste Building - Common	160 days	05/06/2025	12/13/2025
297	Demolish Auxiliary Control Building - Common	160 days	11/18/2025	06/27/2026
298	Remove Systems and Demolish Make-Up Demineralizer Structures	120 days	07/16/2024	12/28/2024
299	Install Concrete Plugs in Intake and Discharge Structures	90 days	08/27/2024	12/28/2024
300	Demolish Intake and Discharge Structures to 3-Feet Below Grade	60 days	11/18/2025	02/07/2026
301	SR Pd 4 Ends	0 days	10/14/2028	10/14/2028
302	**SR Pd 5 - Subgrade Structure Removal Below -3 Feet**	**820 days**	**10/14/2028**	**12/05/2031**
303	SR Pd 5 Begins	0 days	10/14/2028	10/14/2028
304	Procure Subsurface Structure Demolition Equipment	520 days	10/17/2028	10/11/2030
305	Install Sheet Piling and Excavation Shoring	120 days	10/17/2028	03/31/2029
306	Install Dewatering System and Effluent Treatment and Discharge Controls	60 days	04/01/2029	06/22/2029
307	**Unit 3 Subsurface Structures**	**480 days**	**06/23/2029**	**04/25/2031**
308	Demolish and Backfill Unit 3 Condensate Storage Area Below -3 Feet	30 days	06/23/2029	08/03/2029
309	Demolish and Backfill Unit 3 Diesel Generator Builidng Below -3 Feet	30 days	08/04/2029	09/14/2029
310	Demolish and Backfill Unit 3 Fuel Handling Building Below -3 Feet	120 days	09/15/2029	03/01/2030
311	Demolish and Backfill Unit 3 Radwaste Building Below -3 Feet	120 days	03/02/2030	08/16/2030
312	Demolish and Backfill Unit 3 Turbine Building Structure Below 9 Ft Elevatior	120 days	06/23/2029	12/07/2029
313	Demolish and Backfill Unit 3 Safety Equipment Building Below -3 Feet	90 days	12/08/2029	04/12/2030
314	Demolish and Backfill Unit 3 Penetration Area Below -3 Feet	60 days	04/13/2030	07/05/2030
315	Demolish and Backfill Unit 3 Full Flow Building Below -3 Feet	60 days	07/06/2030	09/27/2030
316	Demolish and Backfill Unit 3 Containment Building Below -3 Feet	180 days	08/17/2030	04/25/2031
317	**Unit 2 Subsurface Structures**	**480 days**	**06/23/2029**	**04/25/2031**
318	Demolish and Backfill Unit 2 Condensate Storage Area Below -3 Feet	30 days	06/23/2029	08/03/2029
319	Demolish and Backfill Unit 2 Diesel Generator Builidng Below -3 Feet	30 days	08/04/2029	09/14/2029
320	Demolish and Backfill Unit 2 Fuel Handling Building Below -3 Feet	120 days	09/15/2029	03/01/2030
321	Demolish and Backfill Unit 2 Radwaste Building Below -3 Feet	120 days	03/02/2030	08/16/2030
322	Demolish and Backfill Unit 2 Turbine Building Structure Below 9 Ft Elevatior	120 days	06/23/2029	12/07/2029
323	Demolish and Backfill Unit 2 Safety Equipment Building Below -3 Feet	90 days	12/08/2029	04/12/2030
324	Demolish and Backfill Unit 2 Penetration Area Below -3 Feet	60 days	04/13/2030	07/05/2030
325	Demolish and Backfill Unit 2 Full Flow Building Below -3 Feet	60 days	07/06/2030	09/27/2030
326	Demolish and Backfill Unit 2 Containment Building Below -3 Feet	180 days	08/17/2030	04/25/2031
327	**Common Subgrade Structures**	**432 days**	**02/16/2029**	**10/11/2030**
328	Demolish and Backfill Intake Structure Inside Seawall Below -3 Feet	220 days	12/08/2029	10/11/2030
329	Remove Off Shore Intake and Outfall Conduits	432 days	02/16/2029	10/11/2030

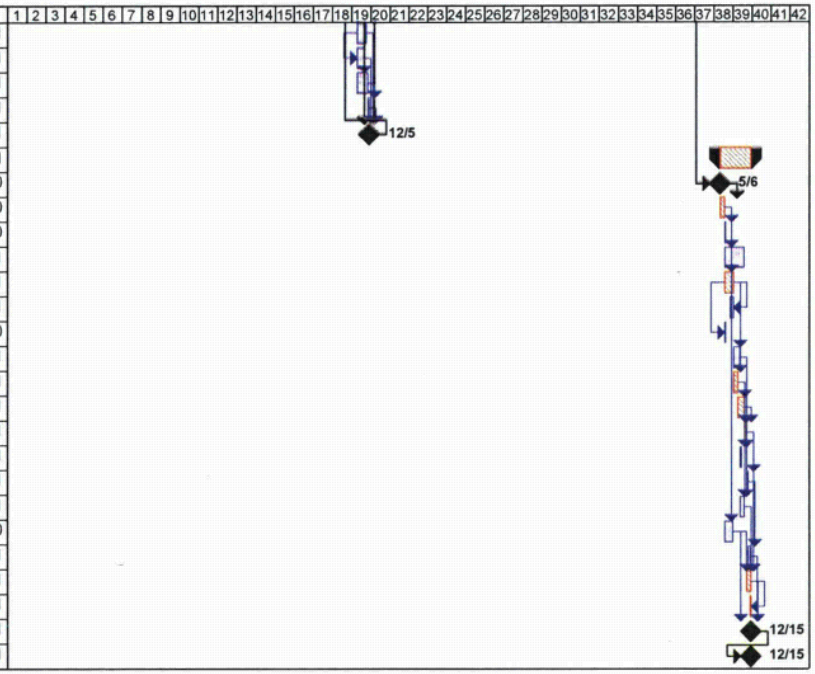


SONGS 2 & 3

Detailed Project Schedule

Prompt DECON, DOE Repository Opens 2024

ID	Task Name	Duration	Start	Finish
330	Remove Sheet Piling and Excavation Shoring	120 days	04/26/2031	10/10/2031
331	Remove Dewatering System and Effluent Treatment	90 days	04/26/2031	08/29/2031
332	Finish Grading and Re-Vegetate Site	140 days	04/26/2031	11/07/2031
333	Remove Temporary Structures	20 days	11/08/2031	12/05/2031
334	SR Pd 5 Ends	0 days	12/05/2031	12/05/2031
335	**SR Pd 6 - Final Site Restoration and Lease Termination**	**420 days**	**05/06/2050**	**12/15/2051**
336	SR Pd 6 Begins	0 days	05/06/2050	05/06/2050
337	Obtain Required Permits and Approvals	60 days	05/07/2050	07/29/2050
338	Install Temporary Structures	10 days	07/30/2050	08/12/2050
339	Procure Site Restoration Equipment	265 days	07/30/2050	08/04/2051
340	Install Temporary Seawall or Coffer Dam	120 days	07/30/2050	01/13/2051
341	Install Dewatering System and Effluent Treatment and Discharge Controls	45 days	11/12/2050	01/13/2051
342	Remove and Stockpile Existing Seawall Erosion Protection	10 days	07/30/2050	08/12/2050
343	Remove Unit 2 and 3 Seawall and Pedestrian Walkway	90 days	01/14/2051	05/19/2051
344	Remove Remaining Intake and Outfall Box Culvert	60 days	01/14/2051	04/07/2051
345	Remove Temporary Seawall or Coffer Dam	90 days	04/08/2051	08/11/2051
346	Backfill and Compaction of Excavation	30 days	08/12/2051	09/22/2051
347	Remove Dewatering System and Effluent Treatment	20 days	05/20/2051	06/16/2051
348	Install Shoreline Erosion Control and Restoration Features	20 days	09/23/2051	10/20/2051
349	Remove Railroad Tracks, Rails and Ballast	60 days	05/20/2051	08/11/2051
350	Remove Gunite Slope Protection	110 days	07/30/2050	12/30/2050
351	Remove Access Roads and Parking Lots	30 days	10/21/2051	12/01/2051
352	Finish Grading and Re-Vegetate Site	60 days	09/23/2051	12/15/2051
353	Remove Temporary Structures	10 days	12/02/2051	12/15/2051
354	SR Pd 6 Ends	0 days	12/15/2051	12/15/2051
355	Final Easement Termination	0 days	12/15/2051	12/15/2051



Appendix D

Detailed Cost Table

Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
A. License Termination							
Decon Pd 1	**Transition to Decommissioning**						
Distributed							
1.05	Disposition of Legacy Wastes	$0	$0	$9,153	$735	$0	$9,888
Distributed	**Subtotal**	**$0**	**$0**	**$9,153**	**$735**	**$0**	**$9,888**
Undistributed							
1.01	Utility Staff	$30,049	$0	$0	$0	$0	$30,049
1.05	Insurance	$0	$0	$0	$5,352	$0	$5,352
1.07	NRC Decommissioning Fees	$0	$0	$0	$1,349	$0	$1,349
1.08	Materials and Services	$0	$0	$0	$1,007	$0	$1,007
1.10	Energy	$0	$0	$0	$2,422	$0	$2,422
1.17	Association Fees and Expenses	$0	$0	$0	$315	$0	$315
1.18	Utilities (Water, gas, phone)	$0	$0	$0	$840	$0	$840
1.20	Non-Process Computers	$0	$0	$0	$224	$0	$224
1.21	Telecommunications	$0	$0	$0	$41	$0	$41
1.22	Personal Computers	$0	$0	$0	$9	$0	$9
1.24	Environmental Permits and Fees	$0	$0	$0	$818	$0	$818
Undistributed	**Subtotal**	**$30,049**	**$0**	**$0**	**$12,378**	**$0**	**$42,426**
Decon Pd 1	**Subtotal**	**$30,049**	**$0**	**$9,153**	**$13,113**	**$0**	**$52,315**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Decon Pd 2	**Decommissioning Planning and Site Modifications**						
Distributed							
2.01	Develop Certified Fuel Handler Program	$143	$1	$0	$0	$36	$180
2.02	Prepare Post-Shutdown QA Plan	$427	$1	$0	$0	$107	$535
2.03	Prepare Post-Shutdown Security Plan	$427	$1	$0	$0	$107	$535
2.04	Prepare Post-Shutdown Fire Protection Plan	$427	$1	$0	$0	$107	$535
2.05	Prepare Defueled Radiation Protection Manual	$427	$1	$0	$0	$107	$535
2.06	Prepare Preliminary Defueled Technical Specifications	$0	$0	$0	$135	$34	$169
2.07	Prepare Defueled Safety Analysis Report (DSAR)	$1,279	$5	$0	$0	$321	$1,605
2.08	Implement Technical Specification Modifications	$1,332	$5	$0	$0	$334	$1,671
2.09	Prepare Post-Shutdown Emergency Preparedness Plan	$634	$1	$0	$0	$159	$793
2.10	NRC Review of Emergency Preparedness Plan	$0	$0	$0	$105	$26	$131
2.11	Prepare Post-Shutdown Decommissioning Activities Report (PSDAR)	$550	$1	$0	$0	$138	$688
2.12	NRC Review of Post-Shutdown Decommissioning Activities Report (PSDAR)	$0	$0	$0	$105	$26	$131
2.13	Respond to NRC quesitons on PSDAR	$34	$1	$0	$0	$9	$43
2.14	Prepare Decommissioning Cost Estimate (DCE)	$1,429	$4	$0	$0	$358	$1,791
2.15	NRC Review of Decommissioning Cost Estimate	$0	$0	$0	$105	$26	$131
2.16	Disposition of Legacy Wastes	$0	$0	$16,457	$0	$4,114	$20,571
2.17	Perform Historic Site Assessment and Site Characterization	$6,784	$838	$0	$0	$1,143	$8,765
2.18	Planning and Design For Cold and Dark	$9,716	$90	$0	$0	$2,451	$12,257
2.19	Implement Cold and Dark (Repower Site)	$16,141	$17,860	$0	$0	$8,500	$42,501
2.20	Install 12kV Service Line to Power Temporary Power Ring	$0	$0	$0	$5,250	$1,313	$6,563
2.21	Drain and De-Energize Non-Essential Systems (DEC Process)	$822	$183	$1,485	$0	$623	$3,114
2.22	Select Decommissioning General Contractor	$645	$8	$0	$0	$163	$817
2.23	Design Spent Fuel Pool Support System Modifications	$622	$8	$0	$0	$157	$787
2.24	Design Control Room Relocation	$601	$7	$0	$0	$152	$760
2.25	Design Spent Fuel Security System Modifications	$459	$5	$0	$0	$116	$580
2.26	Install Spent Fuel Pool System Modifications - Unit 2	$1,863	$4,101	$0	$0	$1,491	$7,456
2.27	Install Spent Fuel Pool System Modifications - Unit 3	$1,863	$4,101	$0	$0	$1,491	$7,456
2.28	Spent Fuel Pool System Modification Training	$0	$0	$0	$273	$68	$341
2.29	Implement Control Room Modifications	$1,004	$1,519	$0	$0	$631	$3,153
2.30	Implement Spent Fuel Pool Security Modifications	$525	$795	$0	$0	$330	$1,650
2.31	Transition Project Modifications	$0	$0	$0	$105	$26	$131

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Distributed	**Subtotal**	**$48,154**	**$29,538**	**$17,942**	**$6,077**	**$24,665**	**$126,376**
Undistributed							
1.01	Utility Staff	$56,478	$0	$0	$0	$14,119	$70,597
1.02	Utility Staff HP Supplies	$0	$1,781	$0	$0	$445	$2,226
1.03	Security Guard Force	$2,087	$0	$0	$0	$522	$2,609
1.04	Security Related Expenses	$77	$0	$0	$0	$19	$96
1.05	Insurance	$0	$0	$0	$4,446	$1,111	$5,557
1.06	Site Lease and Easement Expenses	$0	$0	$0	$470	$70	$540
1.07	NRC Decommissioning Fees	$0	$0	$0	$2,390	$598	$2,988
1.08	Materials and Services	$0	$3,208	$0	$0	$802	$4,010
1.09	DAW Disposal	$0	$0	$295	$0	$74	$369
1.10	Energy	$0	$0	$0	$6,338	$1,584	$7,922
1.13	Craft Worker Training	$234	$0	$0	$0	$58	$292
1.14	Workers Compensation Insurance	$0	$0	$0	$283	$71	$353
1.15	Community Outreach	$1,638	$0	$0	$1,830	$867	$4,335
1.16	Property Tax	$0	$0	$0	$2,350	$588	$2,938
1.17	Association Fees and Expenses	$0	$2,350	$0	$0	$588	$2,938
1.18	Utilities (Water, gas, phone)	$0	$738	$0	$0	$185	$923
1.20	Non-Process Computers	$0	$157	$0	$0	$39	$196
1.21	Telecommunications	$0	$157	$0	$0	$39	$196
1.24	Environmental Permits and Fees	$0	$0	$0	$2,977	$744	$3,721
1.25	Decommissioning Advisor	$0	$0	$0	$1,567	$392	$1,958
Undistributed	**Subtotal**	**$60,513**	**$8,391**	**$295**	**$22,650**	**$22,915**	**$114,764**
Decon Pd 2	**Subtotal**	**$108,667**	**$37,928**	**$18,237**	**$28,727**	**$47,581**	**$241,140**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Decon Pd 3	**Decommissioning Preparations and Reactor Internals Segmentation**						
Distributed							
3.01	Prepare Integrated Work Sequence and Schedule for Decommissioning	$952	$0	$0	$0	$238	$1,190
3.02	Prepare Detailed Work Procedures and Activity Specifications for Decommissioning	$14,920	$70	$0	$0	$3,748	$18,738
3.03	Planning and Design of Primary System Decontamination	$516	$4	$0	$0	$130	$649
3.04	Planning and Design Site Infrastructure Improvements	$341	$4	$0	$0	$86	$431
3.05	Design Containment Access Modifications	$557	$6	$0	$0	$141	$705
3.06	Primary System Decontamination - Unit 2	$1,447	$1,857	$2,228	$0	$1,383	$6,914
3.07	Primary System Decontamination - Unit 3	$1,447	$1,857	$2,228	$0	$1,383	$6,914
3.08	Hot Spot Decontamination - Unit 2	$580	$887	$743	$0	$552	$2,761
3.09	Hot Spot Decontamination - Unit 3	$580	$913	$743	$0	$559	$2,794
3.10	Modify Containment Access- Unit 2	$315	$611	$0	$0	$231	$1,157
3.11	Modify Containment Access- Unit 3	$315	$611	$0	$0	$231	$1,157
3.12	Remove and Dispose of Missle Shields - Unit 2	$206	$30	$81	$0	$79	$395
3.13	Remove and Dispose of Reactor Head - Unit 2	$879	$453	$2,463	$0	$949	$4,744
3.14	Remove and Dispose of Missile Shields - Unit 3	$437	$178	$3,375	$0	$997	$4,987
3.15	Remove and Dispose of Reactor Head - Unit 3	$879	$453	$2,463	$0	$949	$4,744
3.16	Finalize Residual Radiation Inventory	$125	$0	$0	$287	$103	$516
3.17	Prepare Activity Specifications	$7,328	$696	$0	$0	$2,006	$10,031
3.18	Select Shipping Casks and Obtain Shipping Permits	$49	$0	$0	$0	$12	$62
3.19	Design, Specify, and Procure Special Items and Materials	$972	$5,379	$0	$0	$1,588	$7,938
3.22	Test Special Cutting and Handling Equipment and Train Operators	$1,157	$148	$0	$0	$326	$1,631
3.23	Finalize Internals and Vessel Segmenting Details - Unit 2	$212	$16	$0	$0	$57	$284
3.24	Segment, Package and Dispose of Reactor Internals - Unit 2	$5,669	$2,036	$62,661	$0	$17,591	$87,957
3.25	Transfer Internals Segmentation Equipment to Unit 3	$131	$19	$0	$0	$37	$187
3.26	Finalize Internals and Vessel Segmenting Details - Unit 3	$212	$16	$0	$0	$57	$284
3.27	Segment, Package and Dispose of Reactor Internals - Unit 3	$5,669	$2,036	$62,661	$0	$17,591	$87,957
3.28	Construct New Change Rooms, Hot Laundry, In-Plant Laydown Areas	$0	$1,290	$0	$0	$194	$1,484
3.29	Procure Non-Engineered Standard Equipment	$0	$5,454	$0	$0	$1,364	$6,818
Distributed	**Subtotal**	**$45,893**	**$25,024**	**$139,643**	**$287**	**$52,583**	**$263,431**
Undistributed							
1.01	Utility Staff	$79,350	$0	$0	$0	$19,837	$99,187

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
1.02	Utility Staff HP Supplies	$0	$2,693	$0	$0	$673	$3,366
1.03	Security Guard Force	$5,484	$0	$0	$0	$1,371	$6,855
1.04	Security Related Expenses	$326	$0	$0	$0	$82	$408
1.05	Insurance	$0	$0	$0	$8,000	$2,000	$10,000
1.06	Site Lease and Easement Expenses	$0	$0	$0	$1,235	$185	$1,420
1.07	NRC Decommissioning Fees	$0	$0	$0	$6,281	$1,570	$7,851
1.08	Materials and Services	$0	$4,582	$0	$0	$1,145	$5,727
1.09	DAW Disposal	$0	$0	$424	$0	$106	$529
1.10	Energy	$0	$0	$0	$10,226	$2,556	$12,782
1.11	Decommissioning General Contractor Staff	$62,219	$0	$0	$0	$15,555	$77,773
1.12	DGC HP Supplies	$0	$1,558	$0	$0	$389	$1,947
1.13	Craft Worker Training	$1,842	$0	$0	$0	$460	$2,302
1.14	Workers Compensation Insurance	$0	$0	$0	$742	$186	$928
1.15	Community Outreach	$4,303	$0	$0	$4,808	$2,278	$11,390
1.16	Property Tax	$0	$0	$0	$6,175	$1,544	$7,719
1.17	Association Fees and Expenses	$0	$6,175	$0	$0	$1,544	$7,719
1.18	Utilities (Water, gas, phone)	$0	$1,106	$0	$0	$277	$1,383
1.19	Tools and Equipment	$0	$182	$0	$0	$45	$227
1.20	Non-Process Computers	$0	$412	$0	$0	$103	$515
1.21	Telecommunications	$0	$412	$0	$0	$103	$515
1.22	Personal Computers	$0	$0	$0	$89	$22	$111
1.24	Environmental Permits and Fees	$0	$0	$0	$7,822	$1,955	$9,777
1.25	Decommissioning Advisor	$0	$0	$0	$4,117	$1,029	$5,146
Undistributed	**Subtotal**	**$153,524**	**$17,119**	**$424**	**$49,495**	**$55,017**	**$275,579**
Decon Pd 3	**Subtotal**	**$199,417**	**$42,144**	**$140,067**	**$49,782**	**$107,600**	**$539,009**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Decon Pd 4	**Plant Systems and Large Component Removal**						
Distributed							
4.01	Upgrade Rail Spur	$0	$0	$0	$3,277	$819	$4,096
4.02	Install GARDIAN System	$0	$0	$0	$525	$131	$656
4.03	Scaffolding for Non-Essential System Removal	$3,516	$1,144	$200	$0	$1,215	$6,075
4.04	Asbestos Abatement and Hazardous Waste Disposal for Non-Essential Systems - Unit	$0	$0	$0	$1,050	$525	$1,575
4.05	Lead Abatement for Non-Essential Systems Removal - Unit 2	$2,287	$23	$411	$0	$1,361	$4,082
4.06	Remove, Package and Dispose of Non-Essential Systems - Unit 2	$33,512	$5,597	$31,969	$0	$17,769	$88,847
4.07	Asbestos Abatement and Hazardous Waste Disposal for Non-Essential Systems - Unit	$0	$0	$0	$1,050	$525	$1,575
4.08	Lead Abatement for Non-Essential Systems - Unit 3	$2,287	$399	$411	$0	$1,549	$4,647
4.09	Remove, Package and Dispose of Non-Essential Systems - Unit 3	$36,851	$6,313	$36,610	$0	$19,944	$99,718
4.10	Remove Underground Diesel Tank - Unit 2	$111	$45	$0	$41	$49	$247
4.11	Remove Underground Diesel Tank - Unit 3	$111	$45	$0	$41	$49	$247
4.12	Remove and Dispose of Spent Fuel Storage Racks - Unit 2	$42	$36	$4,922	$0	$1,250	$6,250
4.13	Remove and Dispose of Spent Fuel Storage Racks - Unit 3	$42	$36	$4,922	$0	$1,250	$6,250
4.14	Remove and Dispose of Legacy Class B and C Waste - Unit 2	$0	$0	$500	$0	$125	$625
4.15	Remove and Dispose of Legacy Class B and C Waste - Unit 3	$0	$0	$500	$0	$125	$625
4.16	Drain Spent Fuel Pool and Process Liquid Waste - Unit 2	$557	$703	$0	$0	$315	$1,575
4.17	Drain Spent Fuel Pool and Process Liquid Waste - Unit 3	$557	$703	$0	$0	$315	$1,575
4.18	Segment, Package and Dispose of Spent Fuel Pool Island Equipment	$11	$2	$107	$0	$30	$150
4.19	Segment and Dispose of Fuel Pool Bridge Crane - Unit 2	$85	$12	$168	$0	$66	$332
4.20	Segment and Dispose of Fuel Pool Bridge Crane - Unit 3	$85	$12	$168	$0	$66	$332
4.21	Flush and Drain Essential Systems Following Fuel Pool Closure	$226	$181	$2,970	$0	$844	$4,221
4.22	Scaffolding for Essential System Removal	$989	$322	$56	$0	$342	$1,708
4.23	Asbestos Abatement and Hazardous Waste Disposal for Essential Systems	$0	$0	$0	$788	$394	$1,181
4.24	Lead Abatement for Essential Systems Removal	$332	$58	$59	$0	$225	$674
4.25	Remove, Package and Dispose of Essential Systems	$33,774	$5,869	$17,264	$0	$14,227	$71,134
4.26	Removal and Disposal of Spent Resins, Filter Media and Tank Sludge	$90	$40	$7,425	$0	$1,889	$9,445
4.27	Reactor Vessel Insulation Removal and Disposal - Unit 2	$105	$12	$147	$0	$66	$331
4.28	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 2	$1,044	$2,834	$29,313	$0	$8,298	$41,489
4.29	Transfer Rx Vessel Segmentation Equipment to Unit 3	$122	$18	$0	$0	$35	$175
4.30	Procure Replacement Non-Engineered Standard Equipment	$0	$454	$0	$0	$114	$568
4.31	Reactor Vessel Insulation Removal and Disposal - Unit 3	$105	$12	$147	$0	$66	$331

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
4.32	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 3	$1,044	$2,834	$29,313	$0	$8,298	$41,489
4.33	Remove and Dispose of Steam Generators - Unit 2	$2,789	$1,288	$18,154	$0	$5,558	$27,788
4.34	Remove and Dispose of Pressurizer - Unit 2	$462	$70	$2,620	$0	$788	$3,940
4.35	Remove and Dispose of Steam Generators - Unit 3	$2,789	$1,288	$18,154	$0	$5,558	$27,788
4.36	Remove and Dispose of Pressurizer - Unit 3	$462	$70	$2,620	$0	$788	$3,940
4.37	Remove and Dispose of Turbine Gantry Crane - Unit 2	$445	$229	$0	$4	$170	$848
4.38	Remove and Dispose of Turbine Gantry Crane - Unit 3	$445	$229	$0	$4	$170	$848
4.39	Prepare License Termination Plan	$1,646	$149	$0	$0	$449	$2,244
Distributed	**Subtotal**	**$126,926**	**$31,029**	**$209,131**	**$6,779**	**$95,755**	**$469,620**
Undistributed							
1.01	Utility Staff	$71,956	$0	$0	$0	$17,989	$89,945
1.02	Utility Staff HP Supplies	$0	$2,715	$0	$0	$679	$3,394
1.03	Security Guard Force	$4,638	$0	$0	$0	$1,159	$5,797
1.04	Security Related Expenses	$1,007	$0	$0	$0	$252	$1,259
1.05	Insurance	$0	$0	$0	$3,653	$913	$4,566
1.06	Site Lease and Easement Expenses	$0	$0	$0	$1,044	$157	$1,201
1.07	NRC Decommissioning Fees	$0	$0	$0	$5,312	$1,328	$6,639
1.08	Materials and Services	$0	$4,204	$0	$0	$1,051	$5,255
1.09	DAW Disposal	$0	$0	$1,568	$0	$392	$1,960
1.10	Energy	$0	$0	$0	$7,568	$1,892	$9,460
1.11	Decommissioning General Contractor Staff	$125,798	$0	$0	$0	$31,449	$157,247
1.12	DGC HP Supplies	$0	$5,834	$0	$0	$1,458	$7,292
1.13	Craft Worker Training	$7,788	$0	$0	$0	$1,947	$9,735
1.14	Workers Compensation Insurance	$0	$0	$0	$628	$157	$785
1.15	Community Outreach	$3,639	$0	$0	$4,066	$1,926	$9,632
1.16	Property Tax	$0	$0	$0	$5,222	$1,306	$6,528
1.18	Utilities (Water, gas, phone)	$0	$1,007	$0	$0	$252	$1,258
1.19	Tools and Equipment	$0	$423	$0	$0	$106	$529
1.20	Non-Process Computers	$0	$348	$0	$0	$87	$435
1.21	Telecommunications	$0	$348	$0	$0	$87	$435
1.24	Environmental Permits and Fees	$0	$0	$0	$6,615	$1,654	$8,268
1.25	Decommissioning Advisor	$0	$0	$0	$2,611	$653	$3,264

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Table 1
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		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Undistributed	**Subtotal**	**$214,826**	**$14,879**	**$1,568**	**$36,718**	**$66,893**	**$334,884**
Decon Pd 4	**Subtotal**	**$341,752**	**$45,908**	**$210,699**	**$43,497**	**$162,649**	**$804,504**

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Table 1
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		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Decon Pd 5	**Building Decontamination**						
Distributed							
5.01	Decon Containment Building - Unit 3	$6,056	$3,318	$54,825	$0	$16,050	$80,249
5.02	Decon Penetration Building - Unit 3	$1,065	$351	$2,933	$0	$1,087	$5,437
5.03	Decon Safety Equipment and MSIV Building - Unit 3	$905	$390	$5,562	$0	$1,715	$8,573
5.04	Decon Fuel Handling Building - Unit 3	$1,275	$577	$16,101	$0	$4,488	$22,442
5.05	Decon Turbine Building - Unit 3	$100	$95	$3,925	$0	$1,030	$5,150
5.06	Decon Containment Building - Unit 2	$6,056	$3,318	$54,825	$0	$16,050	$80,249
5.07	Decon Penetration Building - Unit 2	$1,065	$351	$2,933	$0	$1,087	$5,437
5.08	Decon Safety Equipment and MSIV Building - Unit 2	$911	$396	$5,777	$0	$1,771	$8,854
5.09	Decon Fuel Handling Building - Unit 2	$1,275	$577	$16,101	$0	$4,488	$22,442
5.10	Decon Turbine Building - Unit 2	$100	$95	$3,925	$0	$1,030	$5,150
5.11	Decon Auxiliary Radwaste Building - Common	$943	$691	$17,999	$0	$4,908	$24,541
5.12	Decon Auxiliary Control Building - Common	$198	$163	$38	$0	$100	$499
5.13	Decon Condensate Area and Tunnels - Units 2 & 3	$375	$316	$403	$0	$274	$1,368
5.14	Excavate, Remove and Dispose of Yard Area Drains	$1,159	$128	$240	$0	$382	$1,908
5.15	Remove and Dispose of Contaminated Sumps, Trenches and Pavement	$185	$21	$746	$0	$238	$1,191
5.16	Remove and Dispose of Radiologically Contaminated Soil	$192	$216	$1,158	$0	$392	$1,958
5.17	Segment, Package and Dispose of Contaminated Decon Equipment and Tooling	$38	$6	$92	$0	$34	$170
5.18	Radiological Survey of Structures During Decon	$4,702	$3,666	$0	$0	$1,255	$9,623
Distributed	**Subtotal**	**$26,600**	**$14,676**	**$187,585**	**$0**	**$56,379**	**$285,240**
Undistributed							
1.01	Utility Staff	$29,516	$0	$0	$0	$7,379	$36,895
1.02	Utility Staff HP Supplies	$0	$997	$0	$0	$249	$1,247
1.03	Security Guard Force	$2,520	$0	$0	$0	$630	$3,150
1.04	Security Related Expenses	$560	$0	$0	$0	$140	$701
1.05	Insurance	$0	$0	$0	$1,985	$496	$2,481
1.06	Site Lease and Easement Expenses	$0	$0	$0	$567	$85	$652
1.07	NRC Decommissioning Fees	$0	$0	$0	$2,886	$722	$3,608
1.08	Materials and Services	$0	$1,668	$0	$0	$417	$2,086
1.09	DAW Disposal	$0	$0	$464	$0	$116	$580
1.10	Energy	$0	$0	$0	$2,336	$584	$2,920

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Table 1
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		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
1.11	Decommissioning General Contractor Staff	$56,286	$0	$0	$0	$14,071	$70,357
1.12	DGC HP Supplies	$0	$3,170	$0	$0	$792	$3,962
1.13	Craft Worker Training	$1,693	$0	$0	$0	$423	$2,116
1.14	Workers Compensation Insurance	$0	$0	$0	$341	$85	$426
1.15	Community Outreach	$862	$0	$0	$964	$457	$2,283
1.16	Property Tax	$0	$0	$0	$2,837	$709	$3,547
1.18	Utilities (Water, gas, phone)	$0	$413	$0	$0	$103	$517
1.19	Tools and Equipment	$0	$204	$0	$0	$51	$255
1.20	Non-Process Computers	$0	$189	$0	$0	$47	$236
1.21	Telecommunications	$0	$189	$0	$0	$47	$236
1.22	Personal Computers	$0	$0	$0	$71	$18	$88
1.24	Environmental Permits and Fees	$0	$0	$0	$3,594	$899	$4,493
1.25	Decommissioning Advisor	$0	$0	$0	$825	$206	$1,031
Undistributed	**Subtotal**	**$91,437**	**$6,832**	**$464**	**$16,406**	**$28,728**	**$143,866**
Decon Pd 5	**Subtotal**	**$118,037**	**$21,508**	**$188,049**	**$16,406**	**$85,106**	**$429,106**

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Table 1
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		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
Decon Pd 6	**License Termination During Demolition**						
Distributed							
6.01	Final Status Survey	$9,613	$3,088	$0	$2,360	$2,259	$17,320
6.02	Prepare Final Report of Dismantling Program	$164	$4	$0	$0	$42	$210
Distributed	**Subtotal**	**$9,777**	**$3,091**	**$0**	**$2,360**	**$2,301**	**$17,530**
Undistributed							
1.01	Utility Staff	$1,378	$0	$0	$0	$345	$1,723
1.04	Security Related Expenses	$4	$0	$0	$0	$1	$5
1.07	NRC Decommissioning Fees	$0	$0	$0	$13,535	$3,384	$16,919
1.08	Materials and Services	$0	$47	$0	$0	$12	$58
1.09	DAW Disposal	$0	$0	$62	$0	$16	$78
1.10	Energy	$0	$0	$0	$1,872	$468	$2,340
1.11	Decommissioning General Contractor Staff	$651	$0	$0	$0	$163	$814
1.12	DGC HP Supplies	$0	$301	$0	$0	$75	$376
1.15	Community Outreach	$2,386	$0	$0	$2,666	$1,263	$6,315
1.18	Utilities (Water, gas, phone)	$0	$10	$0	$0	$3	$13
Undistributed	**Subtotal**	**$4,420**	**$357**	**$62**	**$18,074**	**$5,728**	**$28,641**
Decon Pd 6	**Subtotal**	**$14,197**	**$3,449**	**$62**	**$20,434**	**$8,029**	**$46,171**
A. License Termination	**Subtotal**	**$812,119**	**$150,936**	**$566,266**	**$171,959**	**$410,965**	**$2,112,246**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
B. Spent Fuel							
SNF Pd 1	**Spent Fuel Management Transition**						
Distributed							
7.01	Security Shut Down Strategy	$0	$0	$0	$8,388	$0	$8,388
7.02	Design and Fabricate Spent Fuel Canisters	$0	$0	$0	$8,842	$0	$8,842
7.03	Post Fukushima Modifications - Unit 2	$0	$0	$0	$126	$0	$126
7.05	Cyber Security Modifications	$0	$0	$0	$1,901	$0	$1,901
Distributed	**Subtotal**	**$0**	**$0**	**$0**	**$19,258**	**$0**	**$19,258**
Undistributed							
2.01	Utility Spent Fuel Staff	$38,478	$0	$0	$0	$0	$38,478
2.04	Security Guard Force	$69,889	$0	$0	$0	$0	$69,889
2.09	Emergency Preparedness Fees	$0	$0	$0	$2,340	$0	$2,340
2.10	Spent Fuel Maintenance	$0	$0	$0	$32	$0	$32
Undistributed	**Subtotal**	**$108,367**	**$0**	**$0**	**$2,372**	**$0**	**$110,739**
SNF Pd 1	**Subtotal**	**$108,367**	**$0**	**$0**	**$21,630**	**$0**	**$129,997**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF Pd 2	**Spent Fuel Transfer to Dry Storage**						
Distributed							
8.01	Security Shut Down Strategy	$0	$0	$0	$2,855	$714	$3,569
8.02	Decay Heat Analysis	$0	$0	$0	$105	$26	$131
8.03	Zirconium Fire/ Shine Analysis	$0	$0	$0	$105	$26	$131
8.05	NRC Review of Irradiated Fuel Management Plan	$0	$0	$0	$105	$26	$131
8.07	ISFSI Pad Study	$0	$0	$0	$103	$26	$129
8.08	Design ISFSI Expansion	$0	$0	$0	$3,150	$788	$3,938
8.09	Construct ISFSI Expansion	$0	$0	$0	$33,600	$8,400	$42,000
8.10	Purchase and Fabrication of Spent Fuel Canisters and AHSMs - Unit 2	$0	$49,613	$0	$0	$12,403	$62,016
8.11	Purchase and Fabrication Spent Fuel Canisters and AHSMs - Unit 3	$0	$50,794	$0	$0	$12,698	$63,492
8.12	Deliver and Load Spent Fuel Canisters and Transfer to ISFSI - Unit 2	$71,338	$17,478	$0	$0	$22,204	$111,021
8.13	Deliver and Load Spent Fuel Canisters and Transfer to ISFSI - Unit 3	$73,037	$17,894	$0	$0	$22,733	$113,664
Distributed	**Subtotal**	**$144,375**	**$135,779**	**$0**	**$40,023**	**$80,044**	**$400,221**
Undistributed							
2.01	Utility Spent Fuel Staff	$90,824	$0	$0	$0	$22,706	$113,530
2.02	Utility Staff HP Supplies	$0	$6,590	$0	$0	$1,647	$8,237
2.04	Security Guard Force	$112,313	$0	$0	$0	$28,078	$140,391
2.05	Security Related Expenses	$1,334	$0	$0	$0	$333	$1,667
2.06	Insurance	$0	$0	$0	$4,408	$1,102	$5,510
2.08	NRC Spent Fuel Fees	$0	$0	$0	$1,107	$277	$1,383
2.09	Emergency Preparedness Fees	$0	$0	$0	$18,756	$4,689	$23,445
2.10	Spent Fuel Maintenance	$0	$0	$0	$2,131	$533	$2,664
2.11	Materials and Services	$0	$5,848	$0	$0	$1,462	$7,310
2.12	DAW Disposal	$0	$0	$275	$0	$69	$343
2.13	Energy	$0	$0	$0	$3,991	$998	$4,989
2.15	Craft Worker Training	$2,119	$0	$0	$0	$530	$2,649
2.18	Utilities (Water, gas, phone)	$0	$3,572	$0	$0	$893	$4,465
2.22	Personal Computers	$0	$0	$0	$14	$3	$17
Undistributed	**Subtotal**	**$206,590**	**$16,010**	**$275**	**$30,406**	**$63,320**	**$316,601**
SNF Pd 2	**Subtotal**	**$350,965**	**$151,789**	**$275**	**$70,429**	**$143,364**	**$716,822**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF Pd 3	**Dry Storage During Decommissioning - Units 1, 2 and 3**						
Undistributed							
2.01	Utility Spent Fuel Staff	$39,894	$0	$0	$0	$9,973	$49,867
2.02	Utility Staff HP Supplies	$0	$1,487	$0	$0	$372	$1,859
2.04	Security Guard Force	$45,944	$0	$0	$0	$11,486	$57,430
2.05	Security Related Expenses	$2,556	$0	$0	$0	$639	$3,195
2.08	NRC Spent Fuel Fees	$0	$0	$0	$2,302	$576	$2,878
2.10	Spent Fuel Maintenance	$0	$0	$0	$1,478	$370	$1,848
2.11	Materials and Services	$0	$2,017	$0	$0	$504	$2,522
2.13	Energy	$0	$0	$0	$1,209	$302	$1,511
2.18	Utilities (Water, gas, phone)	$0	$1,380	$0	$0	$345	$1,725
2.22	Personal Computers	$0	$0	$0	$12	$3	$15
Undistributed	**Subtotal**	**$88,393**	**$4,884**	**$0**	**$5,001**	**$24,570**	**$122,849**
SNF Pd 3	**Subtotal**	**$88,393**	**$4,884**	**$0**	**$5,001**	**$24,570**	**$122,849**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF Pd 4	**Dry Storage Only - Units 1, 2 and 3**						
Undistributed							
2.01	Utility Spent Fuel Staff	$12,687	$0	$0	$0	$3,172	$15,859
2.02	Utility Staff HP Supplies	$0	$882	$0	$0	$220	$1,102
2.03	Additional Staff for Spent Fuel Shipping	$1,119	$0	$0	$0	$280	$1,398
2.04	Security Guard Force	$14,949	$0	$0	$0	$3,737	$18,687
2.05	Security Related Expenses	$2,506	$0	$0	$0	$626	$3,132
2.06	Insurance	$0	$0	$0	$2,538	$634	$3,172
2.07	Site Lease and Easement Expenses	$0	$0	$0	$1,154	$173	$1,327
2.08	NRC Spent Fuel Fees	$0	$0	$0	$1,638	$409	$2,047
2.10	Spent Fuel Maintenance	$0	$0	$0	$481	$120	$601
2.11	Materials and Services	$0	$778	$0	$0	$194	$972
2.13	Energy	$0	$0	$0	$393	$98	$492
2.16	Workers Compensation Insurance	$0	$0	$0	$694	$173	$867
2.17	Property Tax	$0	$0	$0	$6,412	$1,603	$8,015
2.18	Utilities (Water, gas, phone)	$0	$475	$0	$0	$119	$594
2.20	Non-Process Computers	$0	$192	$0	$0	$48	$240
2.21	Telecommunications	$0	$192	$0	$0	$48	$240
2.22	Personal Computers	$0	$0	$0	$15	$4	$18
Undistributed	**Subtotal**	**$31,261**	**$2,519**	**$0**	**$13,325**	**$11,661**	**$58,765**
SNF Pd 4	**Subtotal**	**$31,261**	**$2,519**	**$0**	**$13,325**	**$11,661**	**$58,765**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF Pd 5	**Dry Storage Only - Units 2 and 3**						
Undistributed							
2.01	Utility Spent Fuel Staff	$48,480	$0	$0	$0	$12,120	$60,601
2.02	Utility Staff HP Supplies	$0	$3,369	$0	$0	$842	$4,211
2.03	Additional Staff for Spent Fuel Shipping	$4,275	$0	$0	$0	$1,069	$5,344
2.04	Security Guard Force	$57,126	$0	$0	$0	$14,281	$71,407
2.05	Security Related Expenses	$4,124	$0	$0	$0	$1,031	$5,155
2.06	Insurance	$0	$0	$0	$9,698	$2,425	$12,123
2.07	Site Lease and Easement Expenses	$0	$0	$0	$4,409	$661	$5,071
2.08	NRC Spent Fuel Fees	$0	$0	$0	$6,259	$1,565	$7,823
2.10	Spent Fuel Maintenance	$0	$0	$0	$1,838	$459	$2,297
2.11	Materials and Services	$0	$2,972	$0	$0	$743	$3,715
2.13	Energy	$0	$0	$0	$1,503	$376	$1,879
2.16	Workers Compensation Insurance	$0	$0	$0	$2,651	$663	$3,314
2.17	Property Tax	$0	$0	$0	$22,053	$5,513	$27,566
2.18	Utilities (Water, gas, phone)	$0	$1,816	$0	$0	$454	$2,270
2.20	Non-Process Computers	$0	$735	$0	$0	$184	$919
2.21	Telecommunications	$0	$735	$0	$0	$184	$919
2.22	Personal Computers	$0	$0	$0	$32	$8	$40
Undistributed	**Subtotal**	**$114,005**	**$9,627**	**$0**	**$48,443**	**$42,578**	**$214,653**
SNF Pd 5	**Subtotal**	**$114,005**	**$9,627**	**$0**	**$48,443**	**$42,578**	**$214,653**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF D&D Pd 1	**ISFSI License Termination**						
Distributed							
12.01	Preparation and NRC Review of License Termination Plan	$116	$0	$0	$163	$70	$349
Distributed	**Subtotal**	**$116**	**$0**	**$0**	**$163**	**$70**	**$349**
Undistributed							
2.01	Utility Spent Fuel Staff	$366	$0	$0	$0	$91	$457
2.02	Utility Staff HP Supplies	$0	$11	$0	$0	$3	$14
2.04	Security Guard Force	$181	$0	$0	$0	$45	$226
2.05	Security Related Expenses	$70	$0	$0	$0	$18	$88
2.06	Insurance	$0	$0	$0	$215	$54	$269
2.07	Site Lease and Easement Expenses	$0	$0	$0	$98	$15	$112
2.08	NRC Spent Fuel Fees	$0	$0	$0	$75	$19	$94
2.11	Materials and Services	$0	$17	$0	$0	$4	$21
2.13	Energy	$0	$0	$0	$102	$26	$128
2.16	Workers Compensation Insurance	$0	$0	$0	$59	$15	$73
2.17	Property Tax	$0	$0	$0	$543	$136	$679
2.18	Utilities (Water, gas, phone)	$0	$7	$0	$0	$2	$9
Undistributed	**Subtotal**	**$617**	**$36**	**$0**	**$1,092**	**$426**	**$2,172**
SNF D&D Pd 1	**Subtotal**	**$733**	**$36**	**$0**	**$1,255**	**$496**	**$2,520**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SNF D&D Pd 2	**ISFSI Demolition**						
Distributed							
13.01	Install GARDIAN Bulk Assay System	$0	$0	$0	$525	$131	$656
13.02	Decon AHSMs	$339	$147	$443	$0	$232	$1,161
13.03	Final Status Survey of ISFSI	$1,589	$256	$0	$0	$277	$2,122
13.04	Clean Demolition of ISFSI AHSMs and Pad	$4,094	$2,590	$3,333	$0	$2,504	$12,521
13.05	Clean Demolition of ISFSI Support Structures	$1,126	$458	$1,372	$0	$739	$3,696
13.06	Restore ISFSI Site	$246	$161	$0	$0	$102	$509
13.07	Preparation of Final Report on Decommissioning and NRC Review	$52	$0	$0	$0	$13	$65
Distributed	**Subtotal**	**$7,446**	**$3,612**	**$5,148**	**$525**	**$3,998**	**$20,729**
Undistributed							
2.01	Utility Spent Fuel Staff	$1,801	$0	$0	$0	$450	$2,251
2.02	Utility Staff HP Supplies	$0	$72	$0	$0	$18	$90
2.04	Security Guard Force	$704	$0	$0	$0	$176	$880
2.05	Security Related Expenses	$37	$0	$0	$0	$9	$46
2.11	Materials and Services	$0	$93	$0	$0	$23	$116
2.12	DAW Disposal	$0	$0	$7	$0	$2	$8
2.13	Energy	$0	$0	$0	$268	$67	$334
2.14	Decommissioning General Contractor Staff	$4,525	$0	$0	$0	$1,131	$5,656
2.15	Craft Worker Training	$189	$0	$0	$0	$47	$236
2.18	Utilities (Water, gas, phone)	$0	$35	$0	$0	$9	$43
2.24	DGC HP Supplies	$0	$159	$0	$0	$40	$199
Undistributed	**Subtotal**	**$7,255**	**$359**	**$7**	**$268**	**$1,972**	**$9,861**
SNF D&D Pd 2	**Subtotal**	**$14,701**	**$3,972**	**$5,154**	**$793**	**$5,970**	**$30,590**
B. Spent Fuel	**Subtotal**	**$708,425**	**$172,826**	**$5,429**	**$160,876**	**$228,639**	**$1,276,196**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
C. Site Restoration							
SR Pd 1	**Transition to Site Restoration**						
Distributed							
14.01	Mesa Site Phase I and II Site Assessment	$0	$0	$0	$42	$11	$53
14.02	Disposition Hazardous Waste from Mesa Site	$0	$0	$0	$211	$106	$317
14.03	Mesa Site Characterization Survey	$988	$261	$0	$0	$312	$1,561
14.04	Fuel Cancellation Expense	$0	$0	$0	$17,679	$0	$17,679
Distributed	**Subtotal**	**$988**	**$261**	**$0**	**$17,932**	**$428**	**$19,610**
Undistributed							
3.05	Site Lease and Easement Expenses	$0	$0	$0	$1,030	$0	$1,030
3.11	Severance	$0	$0	$0	$109,850	$0	$109,850
Undistributed	**Subtotal**	**$0**	**$0**	**$0**	**$110,880**	**$0**	**$110,880**
SR Pd 1	**Subtotal**	**$988**	**$261**	**$0**	**$128,812**	**$428**	**$130,489**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SR Pd 2	**Building Demolition During Decommissioning**						
Distributed							
15.01	Prepare Site Restoration Demolition Plan and Schedule	$684	$10	$0	$0	$173	$866
15.02	Obtain Required Permits For Mesa, South Access and South Yard	$209	$4	$0	$0	$53	$266
15.03	Demolish Service Building (K-10, 20, 30)	$250	$189	$481	$0	$230	$1,150
15.04	Demolish South Security Processing Facility (K-70)	$46	$44	$122	$0	$53	$264
15.05	Demolish Staging Warehouse	$67	$55	$126	$0	$62	$311
15.06	Demolish Administration Building (K-40/50)	$367	$258	$565	$0	$297	$1,487
15.07	Demolish South Yard Area Buildings T-10, 20, 60 and Haz Mat.	$670	$590	$1,370	$0	$658	$3,288
15.08	Demolish REMS Staging Pad	$98	$184	$549	$0	$208	$1,038
15.09	Demolish Mesa Buildings	$2,788	$1,879	$6,006	$0	$2,668	$13,341
15.10	Remove Underground Fuel Storage Tanks	$56	$22	$0	$21	$25	$123
15.11	Demolish Mesa Roads and Parking Lots	$582	$400	$0	$0	$245	$1,227
15.12	Finish Grading and Re-vegetate Mesa Site	$299	$404	$0	$0	$176	$878
Distributed	**Subtotal**	**$6,114**	**$4,038**	**$9,219**	**$21**	**$4,848**	**$24,239**
Undistributed							
3.01	Utility Staff	$2,563	$0	$0	$0	$641	$3,204
3.03	Security Related Expenses	$898	$0	$0	$0	$224	$1,122
3.05	Site Lease and Easement Expenses	$0	$0	$0	$4,266	$640	$4,906
3.06	Materials and Services	$0	$134	$0	$0	$34	$168
3.08	Decommissioning General Contractor Staff	$4,248	$0	$0	$0	$1,062	$5,310
3.09	Craft Worker Training	$318	$0	$0	$0	$80	$398
3.11	Severance	$0	$0	$0	$8,688	$2,172	$10,860
3.13	Utilities (Water, gas, phone)	$0	$29	$0	$0	$7	$36
Undistributed	**Subtotal**	**$8,027**	**$164**	**$0**	**$12,955**	**$4,860**	**$26,005**
SR Pd 2	**Subtotal**	**$14,141**	**$4,201**	**$9,219**	**$12,975**	**$9,708**	**$50,245**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SR Pd 3	**Subsurface Demolition Engineering and Permitting**						
Distributed							
16.01	Hydrogeologic Investigation and Outfall Conduit Survey	$297	$131	$0	$105	$133	$667
16.02	Subsurface Structure Removal Engineering Planning and Design	$1,264	$33	$0	$0	$324	$1,621
16.03	Environmental Impacts Analyses for Lease Termination Activities	$581	$50	$0	$525	$289	$1,445
16.04	Final Site Grading and Shoreline Protection Engineering Planning and Design	$242	$13	$0	$0	$64	$319
16.05	Obtain Required Permits and Approvals	$1,856	$20	$0	$263	$535	$2,673
Distributed	**Subtotal**	**$4,240**	**$248**	**$0**	**$893**	**$1,345**	**$6,726**
Undistributed							
3.03	Security Related Expenses	$275	$0	$0	$0	$69	$344
3.11	Severance	$0	$0	$0	$24,674	$6,168	$30,842
Undistributed	**Subtotal**	**$275**	**$0**	**$0**	**$24,674**	**$6,237**	**$31,186**
SR Pd 3	**Subtotal**	**$4,516**	**$248**	**$0**	**$25,566**	**$7,582**	**$37,912**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SR Pd 4	**Building Demolition to 3 Feet Below Grade**						
Distributed							
17.01	Procure Clean Building Demolition Equipment	$0	$10,691	$0	$0	$2,673	$13,363
17.02	Install Temporary Structures	$11	$190	$0	$0	$30	$230
17.03	Install Erosion and Sediment Controls	$123	$14	$0	$0	$34	$172
17.04	Remove Cathodic Protection Trench	$1,813	$1,527	$22	$0	$840	$4,201
17.05	Remove Protected Area Security Fencing	$57	$18	$0	$0	$19	$95
17.06	Remove Protected Area Pavement	$139	$97	$755	$0	$248	$1,239
17.07	Detension and Remove Unit 3 Containment Builidng Tendons	$0	$0	$0	$4,200	$1,050	$5,250
17.08	Demolish Diesel Generator Building - Unit 3	$618	$245	$794	$0	$414	$2,072
17.09	Demolish Condensate Building and Transformer Pads - Unit 3	$1,067	$1,755	$3,183	$0	$1,501	$7,505
17.10	Demolish Full Flow Area and Turbine Building - Unit 3	$3,221	$1,149	$3,444	$0	$1,953	$9,767
17.11	Demolish Unit 3 Fuel Handling Building to 3-Feet Below Grade	$306	$354	$1,470	$0	$533	$2,663
17.12	Demolish Penetration Building - Unit 3	$293	$167	$642	$0	$275	$1,377
17.13	Demolish Safety Equipment and MSIV Building - Unit 3	$336	$403	$1,858	$0	$649	$3,246
17.14	Demolish Unit 3 Containment Building to 3-Feet Below Grade	$2,418	$1,351	$6,198	$0	$2,492	$12,459
17.15	Detension and Remove Unit 2 Containment Builidng Tendons	$0	$0	$0	$4,200	$1,050	$5,250
17.16	Demolish Diesel Generator Building - Unit 2	$128	$168	$787	$0	$271	$1,353
17.17	Demolish Condensate Building and Transformer Pads - Unit 2	$1,067	$1,755	$3,183	$0	$1,501	$7,505
17.18	Demolish Full Flow Area and Turbine Building - Unit 2	$3,734	$1,186	$3,447	$0	$2,092	$10,458
17.19	Demolish Unit 2 Fuel Handling Building to 3-Feet Below Grade	$306	$354	$1,470	$0	$533	$2,663
17.20	Demolish Penetration Building - Unit 2	$99	$136	$639	$0	$219	$1,093
17.21	Demolish Safety and MSIV Equipment Building - Unit 2	$336	$403	$1,859	$0	$649	$3,247
17.22	Demolish Unit 2 Containment Building to 3-Feet Below Grade	$2,418	$1,351	$6,198	$0	$2,492	$12,459
17.23	Demolish AWS Building	$1,108	$1,050	$2,925	$0	$1,271	$6,354
17.24	Demolish Building L-50	$59	$33	$67	$0	$40	$198
17.25	Demolish Maintenance Building 4 (B-64/B-65)	$24	$13	$25	$0	$16	$78
17.26	Demolish Maintenance Building 5 (B-62/B-63)	$35	$20	$37	$0	$23	$115
17.27	Demolish Outage Control Center	$98	$57	$148	$0	$76	$378
17.28	Demolish Maintenance Building 2 (B-49/B-50)	$49	$32	$82	$0	$41	$205
17.29	Demolish Maintenance Building 1 (B-43/B-44)	$163	$196	$857	$0	$304	$1,520
17.30	Demolish Auxilary Radwaste Building - Common	$1,521	$1,984	$9,214	$0	$3,180	$15,898
17.31	Demolish Auxilary Control Building - Common	$1,491	$811	$3,219	$0	$1,380	$6,901

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
17.32	Remove Systems and Demolish Make-Up Demineralizer Structures	$737	$122	$471	$0	$332	$1,662
17.33	Install Concrete Plugs in Intake and Discharge Structures	$272	$1,614	$0	$0	$472	$2,358
17.34	Demolish Intake and Discharge Structures to 3-Feet Below Grade	$82	$114	$535	$0	$183	$914
Distributed	**Subtotal**	**$24,128**	**$29,358**	**$53,530**	**$8,400**	**$28,834**	**$144,249**
Undistributed							
3.01	Utility Staff	$12,553	$0	$0	$0	$3,138	$15,691
3.02	Security Guard Force	$2,480	$0	$0	$0	$620	$3,100
3.03	Security Related Expenses	$1,158	$0	$0	$0	$290	$1,448
3.04	Insurance	$0	$0	$0	$3,995	$999	$4,993
3.05	Site Lease and Easement Expenses	$0	$0	$0	$1,340	$201	$1,541
3.06	Materials and Services	$0	$751	$0	$0	$188	$938
3.07	Energy	$0	$0	$0	$1,184	$296	$1,480
3.08	Decommissioning General Contractor Staff	$50,906	$0	$0	$0	$12,727	$63,633
3.09	Craft Worker Training	$1,999	$0	$0	$0	$500	$2,498
3.10	Workers Compensation Insurance	$0	$0	$0	$806	$201	$1,007
3.11	Severance	$0	$0	$0	$7,273	$1,818	$9,091
3.12	Property Tax	$0	$0	$0	$6,701	$1,675	$8,377
3.13	Utilities (Water, gas, phone)	$0	$214	$0	$0	$53	$267
3.14	Tools and Equipment	$0	$156	$0	$0	$39	$195
3.15	Non-Process Computers	$0	$223	$0	$0	$56	$279
3.16	Telecommunications	$0	$223	$0	$0	$56	$279
Undistributed	**Subtotal**	**$69,096**	**$1,567**	**$0**	**$21,298**	**$22,856**	**$114,817**
SR Pd 4	**Subtotal**	**$93,224**	**$30,924**	**$53,530**	**$29,698**	**$51,690**	**$259,066**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SR Pd 5	**Subgrade Structure Removal Below - 3 Feet**						
Distributed							
18.01	Procure Subsurface Structure Demolition Equipment	$0	$6,630	$0	$0	$1,658	$8,288
18.02	Install Sheet Piling and Excavation Shoring	$8,468	$17,219	$0	$0	$6,422	$32,109
18.03	Install Dewatering System and Effluent Treatment and Discharge Controls	$0	$0	$0	$9,651	$2,413	$12,064
18.04	Demolish and Backfill Unit 3 Condensate Storage Area Below -3 Feet	$179	$305	$912	$0	$349	$1,746
18.05	Demolish and Backfill Unit 3 Diesel Generator Builidng Below -3 Feet	$130	$173	$442	$0	$186	$932
18.06	Demolish and Backfill Unit 3 Fuel Handling Building Below -3 Feet	$271	$696	$1,170	$0	$534	$2,671
18.07	Demolish and Backfill Unit 3 Radwaste and Control Building Below -3 Feet	$1,367	$3,268	$5,249	$0	$2,471	$12,355
18.08	Demolish and Backfill Unit 3 Turbine Building Structure Below 9 Ft Elevation	$3,956	$9,277	$12,551	$0	$6,446	$32,231
18.09	Demolish and Backfill Unit 3 Safety Equipment Building Below -3 Feet	$717	$1,883	$2,713	$0	$1,328	$6,641
18.10	Demolish and Backfill Unit 3 Penetration Area Below -3 Feet	$294	$586	$1,285	$0	$541	$2,706
18.11	Demolish and Backfill Unit 3 Full Flow Building Below -3 Feet	$167	$527	$411	$0	$276	$1,382
18.12	Demolish and Backfill Unit 3 Containment Building Below -3 Feet	$1,211	$2,214	$4,636	$0	$2,015	$10,077
18.13	Demolish and Backfill Unit 2 Condensate Storage Area Below -3 Feet	$179	$305	$912	$0	$349	$1,746
18.14	Demolish and Backfill Unit 2 Diesel Generator Builidng Below -3 Feet	$130	$173	$442	$0	$186	$932
18.15	Demolish and Backfill Unit 2 Fuel Handling Building Below -3 Feet	$271	$696	$1,170	$0	$534	$2,671
18.16	Demolish and Backfill Unit 2 Radwaste and Control Building Below -3 Feet	$1,415	$3,308	$5,249	$0	$2,493	$12,466
18.17	Demolish and Backfill Unit 2 Turbine Building Structure Below 9 Ft Elevation	$3,959	$9,277	$12,551	$0	$6,447	$32,234
18.18	Demolish and Backfill Unit 2 Safety Equipment Building Below -3 Feet	$717	$1,883	$2,713	$0	$1,328	$6,641
18.19	Demolish and Backfill Unit 2 Penetration Area Below -3 Feet	$294	$586	$1,285	$0	$541	$2,706
18.20	Demolish and Backfill Unit 2 Full Flow Building Below -3 Feet	$167	$527	$411	$0	$276	$1,382
18.21	Demolish and Backfill Unit 2 Containment Building Below -3 Feet	$1,211	$2,214	$4,636	$0	$2,015	$10,077
18.22	Demolish and Backfill Intake Structure Below -3 Feet	$6,664	$12,970	$36,706	$0	$14,085	$70,426
18.23	Remove Off Shore Intake and Outfall Conduits	$12,406	$44,308	$19,580	$0	$19,073	$95,367
18.24	Remove Sheet Piling and Excavation Shoring	$11,776	$0	$0	$0	$2,944	$14,721
18.25	Remove Dewatering System and Effluent Treatment	$0	$0	$0	$2,308	$577	$2,885
18.26	Finish Grading and Re-Vegetate Site	$945	$813	$0	$0	$440	$2,198
18.27	Remove Temporary Structures	$58	$48	$0	$0	$16	$122
Distributed	**Subtotal**	**$56,952**	**$119,889**	**$115,025**	**$11,959**	**$75,946**	**$379,772**
Undistributed							
3.01	Utility Staff	$7,082	$0	$0	$0	$1,771	$8,853

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
3.02	Security Guard Force	$1,830	$0	$0	$0	$458	$2,288
3.03	Security Related Expenses	$139	$0	$0	$0	$35	$173
3.04	Insurance	$0	$0	$0	$2,948	$737	$3,685
3.05	Site Lease and Easement Expenses	$0	$0	$0	$989	$148	$1,137
3.06	Materials and Services	$0	$415	$0	$0	$104	$519
3.07	Energy	$0	$0	$0	$814	$204	$1,018
3.08	Decommissioning General Contractor Staff	$26,176	$0	$0	$0	$6,544	$32,720
3.09	Craft Worker Training	$983	$0	$0	$0	$246	$1,229
3.10	Workers Compensation Insurance	$0	$0	$0	$595	$149	$743
3.11	Severance	$0	$0	$0	$2,050	$513	$2,563
3.12	Property Tax	$0	$0	$0	$4,946	$1,237	$6,183
3.13	Utilities (Water, gas, phone)	$0	$128	$0	$0	$32	$160
3.14	Tools and Equipment	$0	$73	$0	$0	$18	$91
3.15	Non-Process Computers	$0	$165	$0	$0	$41	$206
3.16	Telecommunications	$0	$165	$0	$0	$41	$206
Undistributed	**Subtotal**	**$36,211**	**$946**	**$0**	**$12,343**	**$12,276**	**$61,775**
SR Pd 5	**Subtotal**	**$93,163**	**$120,834**	**$115,025**	**$24,302**	**$88,222**	**$441,547**

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
SR Pd 6	**Final Site Restoration and Lease Termination**						
Distributed							
19.01	Obtain Required Permits and Approvals	$404	$20	$0	$131	$139	$693
19.02	Install Temporary Structures	$6	$35	$0	$0	$6	$48
19.03	Procure Site Restoration Equipment	$0	$404	$0	$0	$101	$505
19.04	Install Temporary Seawall or Coffer Dam	$8,551	$17,624	$0	$0	$6,544	$32,718
19.05	Install Dewatering System and Effluent Treatment and Discharge Controls	$0	$0	$0	$1,427	$357	$1,784
19.06	Remove and Stockpile Existing Seawall Erosion Protection	$6	$11	$0	$0	$4	$21
19.07	Remove Unit 2 and 3 Seawall and Pedestrian Walkway	$3,206	$3,060	$4,558	$0	$2,706	$13,530
19.08	Remove Remaining Intake and Outfall Box Culvert	$336	$468	$2,188	$0	$748	$3,739
19.09	Remove Temporary Seawall or Coffer Dam	$11,791	$143	$0	$0	$2,983	$14,917
19.10	Backfill and Compaction of Excavation	$1,471	$2,238	$0	$0	$556	$4,265
19.11	Remove Dewatering System and Effluent Treatment	$0	$0	$0	$592	$148	$740
19.12	Install Shoreline Erosion Control and Restoration Features	$10	$144	$0	$0	$38	$192
19.13	Remove Railroad Tracks, Rails and Ballast	$63	$35	$0	$0	$24	$122
19.14	Remove Gunite Slope Protection	$262	$366	$1,710	$0	$585	$2,923
19.15	Remove Access Roads and Parking Lots	$240	$181	$0	$0	$105	$527
19.16	Finish Grading and Re-Vegetate Site	$27	$28	$0	$0	$14	$68
19.17	Remove Temporary Structures	$8	$7	$0	$0	$2	$18
Distributed	**Subtotal**	**$26,380**	**$24,763**	**$8,456**	**$2,151**	**$15,061**	**$76,810**
Undistributed							
3.01	Utility Staff	$2,219	$0	$0	$0	$555	$2,773
3.04	Insurance	$0	$0	$0	$605	$151	$756
3.05	Site Lease and Easement Expenses	$0	$0	$0	$507	$76	$583
3.06	Materials and Services	$0	$142	$0	$0	$35	$177
3.07	Energy	$0	$0	$0	$418	$104	$522
3.08	Decommissioning General Contractor Staff	$8,062	$0	$0	$0	$2,016	$10,078
3.09	Craft Worker Training	$504	$0	$0	$0	$126	$630
3.10	Workers Compensation Insurance	$0	$0	$0	$305	$76	$381
3.11	Severance	$0	$0	$0	$6,077	$1,519	$7,596
3.12	Property Tax	$0	$0	$0	$2,536	$634	$3,169
3.13	Utilities (Water, gas, phone)	$0	$31	$0	$0	$8	$38

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Table 1
SONGS Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

		License Status	POL	Unit 2 Shut Down:	6/7/2013
Decommissioning Alternative	DECON	Fuel Pool Systems	Modified	Unit 3 Shut Down:	6/7/2013
Spent Fuel Alternative	Dry	Repository Opening Date:	1/1/2024		

2014 Dollars in Thousands

No	Item Description	Labor	Equipment	Disposal	Other	Contingency	Total
3.14	Tools and Equipment	$0	$24	$0	$0	$6	$31
Undistributed	**Subtotal**	**$10,785**	**$197**	**$0**	**$10,446**	**$5,307**	**$26,735**
SR Pd 6	**Subtotal**	**$37,165**	**$24,960**	**$8,456**	**$12,597**	**$20,367**	**$103,545**
C. Site Restoration	**Subtotal**	**$243,198**	**$181,428**	**$186,230**	**$233,951**	**$177,997**	**$1,022,804**
	Total	**$1,763,742**	**$505,191**	**$757,925**	**$566,786**	**$817,601**	**$4,411,246**

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Appendix E

Annual Cash Flow Table

SONGS Annual Cost By Account

Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

Unit No: Unit 2

2014 Dollars in Thousands

Year	License Termination	Spent Fuel	Site Restoration	Total
2013	$25,749	$63,891	$49,067	$138,706
2014	$79,799	$35,719	$15,089	$130,607
2015	$69,196	$106,308	$7,439	$182,943
2016	$54,541	$59,308	$3,730	$117,579
2017	$111,903	$59,308	$1,957	$173,168
2018	$47,520	$59,308	$0	$106,828
2019	$108,328	$27,554	$13,539	$149,420
2020	$185,482	$4,908	$36	$190,426
2021	$79,081	$4,908	$36	$84,026
2022	$54,785	$4,908	$1,927	$61,621
2023	$158,207	$4,908	$36	$163,151
2024	$37,930	$4,908	$16,848	$59,687
2025	$2,922	$4,908	$44,621	$52,451
2026	$2,922	$4,908	$19,412	$27,243
2027	$2,922	$4,908	$22,469	$30,299
2028	$2,922	$4,908	$31,688	$39,518
2029	$2,922	$4,908	$66,873	$74,704
2030	$2,922	$4,908	$71,867	$79,697
2031	$2,055	$5,089	$23,181	$30,325
2032	$2,122	$7,214	$0	$9,336
2033	$0	$7,214	$0	$7,214
2034	$0	$7,214	$0	$7,214
2035	$0	$7,228	$0	$7,228
2036	$0	$7,665	$0	$7,665
2037	$0	$7,665	$0	$7,665
2038	$0	$7,665	$0	$7,665
2039	$0	$7,665	$0	$7,665
2040	$0	$7,665	$0	$7,665
2041	$0	$7,665	$0	$7,665
2042	$0	$7,665	$0	$7,665
2043	$0	$7,665	$0	$7,665
2044	$0	$7,665	$0	$7,665
2045	$0	$7,665	$0	$7,665
2046	$0	$7,665	$0	$7,665
2047	$0	$7,665	$0	$7,665
2048	$0	$7,665	$0	$7,665

SONGS Annual Cost By Account

Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

Unit No: Unit 2

2014 Dollars in Thousands

Year	License Termination	Spent Fuel	Site Restoration	Total
2049	$0	$7,667	$0	$7,667
2050	$0	$9,974	$20,177	$30,151
2051	$0	$6,573	$11,928	$18,500
2052	$0	$0	$1,377	$1,377
Total	$1,034,230	$623,209	$423,297	$2,080,735

SONGS Annual Cost By Account

Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

Unit No: Unit 3

2014 Dollars in Thousands

Year	License Termination	Spent Fuel	Site Restoration	Total
2013	$26,566	$66,105	$49,067	$141,739
2014	$78,964	$40,156	$15,969	$135,089
2015	$74,096	$112,024	$9,390	$195,509
2016	$61,451	$64,405	$25,227	$151,083
2017	$40,631	$64,405	$3,799	$108,835
2018	$86,348	$64,405	$0	$150,753
2019	$96,521	$29,675	$13,908	$140,104
2020	$120,873	$4,908	$2,135	$127,916
2021	$194,090	$4,908	$575	$199,574
2022	$135,313	$4,908	$2,467	$142,688
2023	$114,581	$4,908	$1,511	$121,000
2024	$26,874	$4,908	$36,778	$68,560
2025	$2,922	$4,908	$40,655	$48,485
2026	$2,922	$4,908	$21,676	$29,507
2027	$2,922	$4,908	$25,848	$33,678
2028	$2,922	$4,908	$20,945	$28,776
2029	$2,922	$4,908	$117,321	$125,151
2030	$2,922	$4,908	$116,672	$124,503
2031	$2,055	$5,089	$25,501	$32,645
2032	$2,122	$7,214	$0	$9,336
2033	$0	$7,214	$0	$7,214
2034	$0	$7,214	$0	$7,214
2035	$0	$7,228	$0	$7,228
2036	$0	$7,665	$0	$7,665
2037	$0	$7,665	$0	$7,665
2038	$0	$7,665	$0	$7,665
2039	$0	$7,665	$0	$7,665
2040	$0	$7,665	$0	$7,665
2041	$0	$7,665	$0	$7,665
2042	$0	$7,665	$0	$7,665
2043	$0	$7,665	$0	$7,665
2044	$0	$7,665	$0	$7,665
2045	$0	$7,665	$0	$7,665
2046	$0	$7,665	$0	$7,665
2047	$0	$7,665	$0	$7,665
2048	$0	$7,665	$0	$7,665

SONGS Annual Cost By Account

Prompt DECON Base Case, 2024 DOE Acceptance, Dry Storage

Unit No: Unit 3

2014 Dollars in Thousands

Year	License Termination	Spent Fuel	Site Restoration	Total
2049	$0	$7,667	$0	$7,667
2050	$0	$9,974	$23,120	$33,094
2051	$0	$6,573	$45,566	$52,139
2052	$0	$0	$1,377	$1,377
Total	$1,078,016	$652,987	$599,507	$2,330,511

Appendix F

SDG&E SONGS Decommissioning Costs (100%)

San Diego Gas & Electric Company (SDG&E) provides the following information regarding its internal decommissioning costs, which it expects to incur and to fund on its own behalf (100%) in addition to its 20% share of the Decommissioning Cost Estimate.

I. BACKGROUND

As the 20% minority owner, SDG&E is contractually obligated to pay its 20% ownership share of decommissioning expenses for SONGS. These costs, outlined in the DCE, will be incurred by the decommissioning agent and SDG&E will receive invoicing for its proportional share.

II. SDG&E COSTS

Table F-1

SDG&E SONGS DECOMMISSIONING COSTS (1,000's, $2014)

Total Units 2 & 3	SDG&E Labor	Other/ Non-Labor	Total Costs
License Termination	$3,832	$1,047	$4,879
Spent Fuel Management	$2,729	$417	$3,147
Site Restoration	$1,904	$401	$2,305
Total	$8,465	$1,865	$10,330

In addition to SDG&E's 20% share of the costs outlined in the DCE, SDG&E also incurs internal costs related to its SONGS ownership. SDG&E incurs 100% of these Labor and Non-Labor costs related to SDG&E's oversight activities. These costs are apportioned into SCE's DCE categories of License Termination, Spent Fuel Management, and Site Restoration by determining the percentage of costs SCE allocated to each category and multiplying SDG&E's

costs by that same percentage for each category. SDG&E estimates that its total internal costs over the decommissioning period to be $10.33 million (2014$).

a. SDG&E LABOR

The first category, "SDG&E Labor" includes SDG&E staff who provide oversight of SONGS costs and activities. SDG&E's internal staffing efforts are expected to mirror site staffing where the three (3) full-time equivalents ("FTEs") are reduced after 2016 to two (2) FTEs, then to one (1) FTE after 2025, and eventually to zero (0) FTEs after 2032. After 2032, invoicing and oversight activities are anticipated to be minor during this period. Once ISFSI decommissioning is initiated on or around 2049, SDG&E plans to identify one (1) full-time equivalent through 2052.

These costs are shown in Table F-1 under the column heading of "SDG&E Labor" and are apportioned into SCE's categories of License Termination, Spent Fuel Management, and Site Restoration.

b. OTHER/NON-LABOR

The second type of SDG&E-specific costs are "Other/Non-Labor", which consist of outside decommissioning consultants and direct costs related to oversight activities.

To provide oversight of decommissioning activities, SDG&E has retained an external decommissioning consultant who has the expertise SDG&E requires. The external consultant is utilized to a greater extent through 2016 and then the consultant services are tapered off annually through 2025.

SDG&E also incurs direct costs related specifically to SDG&E's oversight activities at SONGS. These costs, which include travel reimbursement, phone services, training, and wireless

communication from SONGS, will coincide with the number of SDG&E SONGS oversight personnel FTEs.

These costs are shown in Table F-1 under the column heading of Other/Non-labor and are apportioned into SCE's categories of License Termination, Spent Fuel Management, and Site Restoration.

III. CONCLUSION

All of SDG&E's internal decommissioning costs presented in Table F-1 are separate and distinct from the costs incurred by the decommissioning agent and invoiced to SDG&E.

SDG&E will seek authority to access its nuclear decommissioning trust funds to pay for its proportional share of SONGS related decommissioning expenses and for its internal decommissioning costs incurred through a Commission-approved advice letter process consistent with the terms of the SDG&E Master Trust Agreement, and relevant rules and regulations of the Internal Revenue Service and the Nuclear Regulatory Commission.

SDG&E SONGS Detailed Annual Expenditures

Base Case: Prompt DECON, Time Reasonable Schedule, DOE Repository Opening 2024, Utility and DGC, Dry Storage
(2014 Dollars in Thousands)

Account Totals

	Unit 2			Unit 3			Total			
	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Total
License Termination	$1,905	$0	$487	$1,927	$0	$560	$3,832	$0	$1,047	$4,879
Spent Fuel Management	$1,349	$0	$184	$1,380	$0	$233	$2,729	$0	$417	$3,147
Site Restoration	$761	$0	$153	$1,143	$0	$248	$1,904	$0	$401	$2,305
	$4,016	**$0**	**$823**	**$4,450**	**$0**	**$1,041**	**$8,465**	**$0**	**$1,865**	**$10,330**

Unit 2

	License Termination			Spent Fuel Management			Site Restoration			ISFSI D&D		
Year	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other
2013	$25	$0	$0	$91	$0	$0	$0	$0	$1	$0	$0	$0
2014	$240	$0	$41	$122	$0	$22	$0	$0	$28	$0	$0	$0
2015	$225	$0	$20	$123	$0	$66	$6	$0	$5	$0	$0	$0
2016	$133	$0	$41	$203	$0	$22	$10	$0	$3	$0	$0	$0
2017	$88	$0	$77	$138	$0	$23	$4	$0	$2	$0	$0	$0
2018	$74	$0	$34	$144	$0	$24	$0	$0	$0	$0	$0	$0
2019	$162	$0	$47	$78	$0	$7	$0	$0	$21	$0	$0	$0
2020	$244	$0	$89	$11	$0	$1	$0	$0	$0	$0	$0	$0
2021	$146	$0	$35	$13	$0	$1	$0	$0	$0	$0	$0	$0
2022	$184	$0	$25	$20	$0	$1	$0	$0	$5	$0	$0	$0
2023	$206	$0	$57	$21	$0	$1	$0	$0	$0	$0	$0	$0
2024	$139	$0	$14	$29	$0	$1	$45	$0	$21	$0	$0	$0
2025	$6	$0	$1	$23	$0	$0	$89	$0	$9	$0	$0	$0
2026	$7	$0	$1	$30	$0	$0	$74	$0	$7	$0	$0	$0
2027	$7	$0	$1	$28	$0	$0	$73	$0	$7	$0	$0	$0
2028	$7	$0	$1	$27	$0	$0	$88	$0	$10	$0	$0	$0
2029	$5	$0	$0	$20	$0	$0	$71	$0	$6	$0	$0	$0
2030	$5	$0	$0	$21	$0	$0	$71	$0	$7	$0	$0	$0
2031	$3	$0	$1	$25	$0	$1	$82	$0	$7	$0	$0	$0
2032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2033	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2036	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2039	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2040	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2041	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2042	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2044	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2045	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2046	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2047	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2048	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2049	$0	$0	$0	$114	$0	$9	$0	$0	$0	$0	$0	$0
2050	$0	$0	$0	$46	$0	$2	$111	$0	$6	$0	$0	$0
2051	$0	$0	$0	$24	$0	$1	$35	$0	$4	$0	$0	$0
2052	$0	$0	$0	$0	$0	$0	$0	$0	$4	$0	$0	$0
	$1,905	**$0**	**$487**	**$1,349**	**$0**	**$184**	**$761**	**$0**	**$153**	**$0**	**$0**	**$0**

Unit 3

	License Termination			Spent Fuel Management			Site Restoration			ISFSI D&D		
	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other
	$25	$0	$0	$91	$0	$0	$0	$0	$1	$0	$0	$0
	$235	$0	$41	$122	$0	$30	$2	$0	$28	$0	$0	$0
	$228	$0	$23	$123	$0	$71	$15	$0	$5	$0	$0	$0
	$134	$0	$53	$206	$0	$32	$34	$0	$38	$0	$0	$0
	$71	$0	$33	$139	$0	$34	$6	$0	$4	$0	$0	$0
	$83	$0	$67	$145	$0	$36	$0	$0	$0	$0	$0	$0
	$127	$0	$46	$79	$0	$10	$1	$0	$21	$0	$0	$0
	$174	$0	$50	$11	$0	$1	$5	$0	$0	$0	$0	$0
	$272	$0	$94	$13	$0	$1	$1	$0	$0	$0	$0	$0
	$220	$0	$83	$20	$0	$1	$1	$0	$6	$0	$0	$0
	$192	$0	$51	$21	$0	$1	$6	$0	$1	$0	$0	$0
	$125	$0	$13	$29	$0	$1	$79	$0	$51	$0	$0	$0
	$6	$0	$1	$23	$0	$0	$83	$0	$8	$0	$0	$0
	$7	$0	$1	$30	$0	$0	$80	$0	$8	$0	$0	$0
	$7	$0	$1	$28	$0	$0	$83	$0	$8	$0	$0	$0
	$7	$0	$1	$27	$0	$0	$73	$0	$5	$0	$0	$0
	$5	$0	$0	$20	$0	$0	$108	$0	$12	$0	$0	$0
	$5	$0	$0	$21	$0	$0	$105	$0	$11	$0	$0	$0
	$3	$0	$1	$25	$0	$1	$89	$0	$8	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$114	$0	$9	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$46	$0	$2	$69	$0	$8	$0	$0	$0
	$0	$0	$0	$24	$0	$1	$152	$0	$11	$0	$0	$0
	$0	$0	$0	$24	$0	$1	$152	$0	$11	$0	$0	$0
	$1,927	**$0**	**$560**	**$1,380**	**$0**	**$233**	**$1,143**	**$0**	**$248**	**$0**	**$0**	**$0**

SDG&E SONGS Detailed Annual Expenditures

Base Cas Prompt DECON, Time Reasonable Schedule, DOE Repository Opening 2024, Utility and DGC, Dry Storage
(2014 Dollars in Thousands)

Account Totals

	Unit 2			Unit 3			Total			
	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Total
License Termination	$1,905	$0	$487	$1,927	$0	$560	$3,832	$0	$1,047	$4,879
Spent Fuel Management	$1,349	$0	$184	$1,380	$0	$233	$2,729	$0	$417	$3,147
Site Restoration	$761	$0	$153	$1,143	$0	$248	$1,904	$0	$401	$2,305
	$4,016	**$0**	**$823**	**$4,450**	**$0**	**$1,041**	**$8,465**	**$0**	**$1,865**	**$10,330**

Unit 2 and 3 Total

Year	License Termination			Spent Fuel Management			Site Restoration			ISFSI D&D		
	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other	Labor	LLRW Burial	Other
2013	$50	$0	$0	$182	$0	$1	$0	$0	$3	$0	$0	$0
2014	$474	$0	$82	$243	$0	$51	$2	$0	$56	$0	$0	$0
2015	$453	$0	$42	$245	$0	$137	$21	$0	$10	$0	$0	$0
2016	$267	$0	$95	$409	$0	$53	$44	$0	$41	$0	$0	$0
2017	$159	$0	$109	$277	$0	$57	$10	$0	$5	$0	$0	$0
2018	$157	$0	$101	$289	$0	$60	$0	$0	$0	$0	$0	$0
2019	$288	$0	$93	$157	$0	$16	$1	$0	$42	$0	$0	$0
2020	$418	$0	$139	$23	$0	$2	$5	$0	$0	$0	$0	$0
2021	$419	$0	$129	$26	$0	$2	$1	$0	$0	$0	$0	$0
2022	$404	$0	$107	$41	$0	$3	$2	$0	$11	$0	$0	$0
2023	$399	$0	$108	$42	$0	$3	$6	$0	$1	$0	$0	$0
2024	$264	$0	$27	$58	$0	$2	$124	$0	$72	$0	$0	$0
2025	$11	$0	$1	$45	$0	$0	$171	$0	$17	$0	$0	$0
2026	$15	$0	$3	$60	$0	$1	$153	$0	$15	$0	$0	$0
2027	$14	$0	$2	$57	$0	$1	$157	$0	$15	$0	$0	$0
2028	$13	$0	$2	$53	$0	$1	$161	$0	$16	$0	$0	$0
2029	$10	$0	$0	$39	$0	$0	$179	$0	$18	$0	$0	$0
2030	$10	$0	$0	$42	$0	$0	$176	$0	$18	$0	$0	$0
2031	$6	$0	$2	$50	$0	$1	$172	$0	$15	$0	$0	$0
2032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2033	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2036	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2039	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2040	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2041	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2042	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2043	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2044	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2045	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2046	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2047	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2048	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2049	$0	$0	$0	$228	$0	$18	$0	$0	$0	$0	$0	$0
2050	$0	$0	$0	$93	$0	$4	$180	$0	$14	$0	$0	$0
2051	$0	$0	$0	$48	$0	$3	$187	$0	$16	$0	$0	$0
2052	$0	$0	$0	$24	$0	$1	$152	$0	$16	$0	$0	$0
	$3,832	**$0**	**$1,047**	**$2,729**	**$0**	**$417**	**$1,904**	**$0**	**$401**	**$0**	**$0**	**$0**

Unit 2 and 3 Project Totals

License Term	Spent Fuel	Site Restoration	Total
$51	$182	$3	$236
$557	$294	$58	$909
$496	$382	$31	$909
$362	$462	$85	$909
$269	$334	$15	$618
$258	$349	$0	$608
$381	$173	$43	$598
$557	$25	$5	$588
$548	$28	$2	$578
$511	$43	$13	$567
$508	$44	$7	$557
$291	$60	$196	$547
$12	$45	$188	$246
$18	$60	$168	$246
$16	$57	$172	$246
$15	$54	$177	$246
$10	$39	$197	$246
$11	$42	$194	$246
$9	$51	$187	$246
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$0	$0	$0
$0	$246	$0	$246
$0	$97	$195	$291
$0	$51	$203	$253
$0	$25	$168	$193
$4,879	**$3,147**	**$2,306**	**$10,330**

EXHIBIT 4

March 3, 2010

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Atomic Safety and Licensing Board

Before Administrative Judges:
Thomas S. Moore, Chairman
Paul S. Ryerson
Richard E. Wardwell

In the Matter of	)	Docket No. 63-001
U.S. DEPARTMENT OF ENERGY	)	ASLBP No. 09-892-HLW-CAB04
(High-Level Waste Repository)	)	

U.S. DEPARTMENT OF ENERGY'S MOTION TO WITHDRAW

The United States Department of Energy ("DOE") hereby moves, pursuant to 10 C.F.R. § 2.107, to withdraw its pending license application for a permanent geologic repository at Yucca Mountain, Nevada. DOE asks the Board to dismiss its application with prejudice and to impose no additional terms of withdrawal.

While DOE reaffirms its obligation to take possession and dispose of the nation's spent nuclear fuel and high-level nuclear waste, the Secretary of Energy has decided that a geologic repository at Yucca Mountain is not a workable option for long-term disposition of these materials. Additionally, at the direction of the President, the Secretary has established the Blue Ribbon Commission on America's Nuclear Future, which will conduct a comprehensive review

and consider alternatives for such disposition.[1] And Congress has already appropriated $5 million for the Blue Ribbon Commission to evaluate and recommend such "alternatives." Energy and Water Development and Related Agencies Appropriations Act, 2010, Pub. L. No. 111-85, 123 Stat. 2845, 2864-65 (2009). In accord with those decisions, and to avoid further expenditure of funds on a licensing proceeding for a project that is being terminated, DOE has decided to discontinue the pending application in this docket,[2] and hereby moves to withdraw that application with prejudice.

Under the Nuclear Waste Policy Act of 1982, as amended, 42 U.S.C. §§ 10101 *et seq.* ("NWPA"), this licensing proceeding must be conducted "in accordance with the laws applicable to such applications . . . ." NWPA § 114(d), 42 U.S.C. § 10134(d). Those laws necessarily include the NRC's regulations governing license applications, including, as this Board has already recognized, 10 C.F.R. § 2.107(a). *See* CAB Order (Concerning LSNA Memorandum), ASLBP No. 09-892-HLW-CAB04, at 2 (Dec. 22, 2009) (stating that "the parties are reminded that, pursuant to 10 C.F.R. § 2.107, withdrawal shall be on such terms as the Board may prescribe."). That section provides in relevant part that "[w]ithdrawal of an application after the

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1 *See* Presidential Memorandum -- Blue Ribbon Commission on America's Nuclear Future (Jan. 29, 2010) ("Presidential Memorandum"), *available at* http://www.whitehouse.gov/the-press-office/presidential-memorandum-blue-ribbon-commission-americas-nuclear-future; Department of Energy Press Release, Secretary Chu Announces Blue Ribbon Commission on America's Nuclear Future (January 29, 2010), *available at* http://www.energy.gov/news/8584.htm; Charter, Blue Ribbon Commission on America's Nuclear Future (filed March 1, 2010), *available at* http://www.energy.gov/news/documents/BRC_Charter.pdf. The Commission will conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle, including all alternatives for the storage, processing, and disposal of civilian and defense used nuclear fuel and materials derived from nuclear activities. *See id.*

2 This decision was announced in the Administration's Fiscal Year 2011 Budget, which states that "[i]n 2010, the Department will discontinue its application to the Nuclear Regulatory Commission (NRC) for a license to construct a high-level waste geologic repository at Yucca Mountain, Nevada." Budget of the U.S. Government, Fiscal Year 2011: Terminations, Reductions, and Savings, at 62 (Feb. 1, 2010). The Department of Energy's Fiscal Year 2011 Congressional Budget Request similarly states that "in 2010, Department will discontinue its application to the U.S. Nuclear Regulatory Commission for a license to construct a high-level waste geologic repository at Yucca Mountain." Department of Energy, FY 2011 Congressional Budget Request, Vol. 7, at 163 (Feb. 2010).

issuance of a notice of hearing shall be on such terms as the presiding officer may prescribe." 10 C.F.R. § 2.107(a).

Thus, applicable Commission regulations empower this Board to regulate the terms and conditions of withdrawal. *Philadelphia Electric Company* (Fulton Generating Station, Units 1 and 2), ALAB-657, 14 N.R.C. 967, 974 (1981). Any terms imposed for withdrawal must bear a rational relationship to the conduct and legal harm at issue. *Id.* And the record must support any findings concerning the conduct and harm in question to impose a term. *Id.*, citing *LeCompte v. Mr. Chip, Inc.*, 528 F.2d 601, 604-05 (5th Cir. 1976); 5 Moore's Federal Practice ¶ 41.05[1] at 41–58.

A. The Board Should Grant Dismissal With Prejudice

In this instance, the Board should prescribe only one term of withdrawal—that the pending application for a permanent geologic repository at the Yucca Mountain site shall be dismissed with prejudice.[3]

That action will provide finality in ending the Yucca Mountain project for a permanent geologic repository and will enable the Blue Ribbon Commission, as established by the Department and funded by Congress, to focus on alternative methods of meeting the federal government's obligation to take high-level waste and spent nuclear fuel. It is the Secretary of Energy's judgment that scientific and engineering knowledge on issues relevant to disposition of high-level waste and spent nuclear fuel has advanced dramatically over the twenty years since the Yucca Mountain project was initiated. *See also* Presidential Memorandum at 1. Future proposals for the disposition of such materials should thus be based on a comprehensive and

[3] DOE seeks this form of dismissal because it does not intend ever to refile an application to construct a permanent geologic repository for spent nuclear fuel and high-level radioactive waste at Yucca Mountain.

careful evaluation of options supported by that knowledge, as well as other relevant factors, including the ability to secure broad public support, not on an approach that "has not proven effective" over several decades. *Id.*

The Board should defer to the Secretary's judgment that dismissal of the pending application with prejudice is appropriate here. Settled law in this area directs the NRC to defer to the judgment of policymakers within the Executive Branch.[4] And whether the public interest would be served by dismissing this application with prejudice is a matter within the purview of the Secretary.[5] From public statements already made, we of course understand that some will nevertheless argue that dismissing this application is contrary to the NWPA. Although it is impossible to anticipate exactly what parties will argue at this point, at least one litigant seeking to raise these issues in federal court has said the NWPA obligation to file the pending application is inconsistent with the decision to withdraw the application. This is simply wrong.

Nothing in the text of the NWPA strips the Secretary of an applicant's ordinary right to seek dismissal. In fact, the text of the statute cuts sharply in favor of the Secretary's right to seek

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[4] *U.S. Department Of Energy* (Plutonium Export License), CLI-04-17, 59 N.R.C. 357, 374 (2004) (deferring, upon "balanc[ing] our statutory role in export licensing with the conduct of United States foreign relations, which is the responsibility of the Executive Branch," to Executive Branch determination on an export license application). *See also Private Fuel Storage, L.L.C.* (Independent Spent Fuel Storage Installation), LBP-03-30, 58 N.R.C. 454, 472 (2003) (expressing "considerable doubt" about the NRC's authority to "second-guess" the Bureau of Land Management on an issue relating to recommendations as to the wilderness status of land, and declining an invitation to do so); *see also Environmental Radiation Protection Standards for Nuclear Power Operations, 40 CFR 190*, CLI–81–4, 13 N.R.C. 298, 301 (1981) (deferring to EPA standards for radiation protection: "This agency does not sit as a reviewing court for a sister agency's regulations…."). *See generally Pacific Gas & Electric Company* (Stanislaus Nuclear Project, Unit 1), LBP-83-2 , 17 N.R.C. 45, 52 (1983) ("The law on withdrawal does not require a determination of whether [the applicant's] decision [to withdraw] is sound.").

[5] The Atomic Energy Act ("AEA" or "Act") gives the Secretary broad authority to carry out the Act's purposes, including the authority to direct the Government's "control of the possession, use, and production of atomic energy and special nuclear material, whether owned by the Government or others, so directed as to make the maximum contribution to the common defense and security and the national welfare." AEA § 3(c), 42 U.S.C. § 2013(c). Indeed, as the D.C. Circuit has recognized, the AEA established "a regulatory scheme which is virtually unique in the degree to which broad responsibility is reposed in the administering agency, free of close prescription in its charter as to how it shall proceed in achieving the statutory objectives." *Siegel v. AEC*, 400 F.2d 778, 783 (D.C. Cir. 1968). While *Siegel* concerned directly the branch of the then-Atomic Energy Commission that later became the NRC, its recognition that broad discretion is to be given to the governmental agencies charged with administering the AEA's objectives applies equally to the Department of Energy, the other lineal descendant of the AEC.

dismissal. The statute simply requires that the Secretary "shall submit . . . an application for a construction authorization." NWPA § 114(b), 42 U.S.C. § 10134(b). It neither directs nor circumscribes the Secretary's actions on the application after that submission.[6]

Indeed, far from imposing special limitations on DOE after the submission, the NWPA expressly requires that the application be considered "in accordance with the laws applicable to such applications." NWPA § 114(d), 42 U.S.C. § 10134(d). Those laws include 10 C.F.R. § 2.107, which, as this Board has recognized, authorizes withdrawals on terms the Board prescribes. Congress, when it enacted the NWPA in 1982, could have dictated that special rules applied to this proceeding to prevent withdrawal motions, or could have prescribed duties by DOE with respect to prosecution of the application after filing, but it chose not to do so.

Nor does the structure of the NWPA somehow override the plain textual indication in the statute that ordinary NRC rules govern here or dictate that the Secretary must continue with an application he has decided is contrary to the public interest. The NWPA does not prescribe a step-by-step process that leads inexorably to the opening of a repository at Yucca Mountain. Indeed, even if the NRC granted the pending application today, the Secretary would not have the authority to create an operational repository. That would require further action by DOE, other agencies, and Congress itself, yet none of those actions is either mandated or even mentioned by the NWPA. The NWPA does not require the Secretary to undertake the actions necessary to obtain the license to receive and possess materials that would be necessary to open a repository. 10 C.F.R. §§ 63.3, 63.32(d). Rather, the NWPA refers only to the need for a "construction

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[6] After filing the application, the only NWPA mandate imposed on the Secretary is a *reporting* requirement to Congress to note the "project decision schedule that portrays the optimum way to attain the operation of the repository, within the time periods specified in this part." NWPA § 114(e)(1), 42 U.S.C. §10134(e)(1).

authorization," NWPA § 114(b), 42 U.S.C. § 10134(b) – and even there, as discussed, it mandates only the submission of an application. To open a facility, moreover, the Department would be required to obtain water rights, rights of way from the Bureau of Land Management for utilities and access roads, and Clean Water Act § 404 permits for repository construction, as well as all the state and federal approvals necessary for an approximately 300-mile rail line, among many other things. None of those actions is mandated by the NWPA. At least as important, as the prior Administration stressed, *Congress* would need to take further action not contained in the NWPA before any such repository could be opened.[7] In short, there are many acts between the filing of the application and the actual use of the repository that the NWPA does not require.

Where, even if the NRC granted the pending application, Congress has not authorized the Secretary to make the Yucca Mountain site operational, or even mandated that he take the many required steps to make it operational, it would be bizarre to read the statute to impose a non-discretionary duty to continue with any particular intermediate step (here, prosecuting the application), absent clear statutory language mandating that result. More generally, it has not been the NRC's practice to require any litigant to maintain a license application that the litigant does not wish to pursue. That deference to an applicant's decisions should apply more strongly where a government official has decided not to pursue a license application because he believes that other courses would better serve the public interest.

Finally, the fact that Congress has approved Yucca Mountain as the site of a repository, *see* Pub. L. No. 107-200, 116 Stat. 735 (2002) ("there hereby is approved the site at Yucca Mountain, Nevada, for a repository, with respect to which a notice of disapproval was submitted

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7 *See* January 2009 Project Decision Schedule at 1 ("This schedule is predicated upon the enactment of legislation ... [regarding] land withdrawal."). *See also, e.g.*, Nuclear Fuel Management and Disposal Act, S.2589, 109th Congress, 2d Sess. § 3 (2006) (proposed legislation authorizing the withdrawal of lands necessary for the Yucca Mountain repository).

by the Governor of the State of Nevada on April 8, 2002"), means, in the D.C. Circuit's words, simply that the Secretary is "permitted" to seek authority to open such a site and that challenges to the prior process to select that site are moot. *Nuclear Energy Institute, Inc. v. EPA*, 373 F.3d 1251, 1309-10 (D.C. Cir. 2004). It does *not* require the Secretary to continue with an application proceeding if the Secretary decides that action is contrary to the public interest. *See, e.g.,* S. Rep. No. 107-159, at 13 (2002) ("It bears repeating that enactment of the joint resolution will not authorize construction of the repository or allow DOE to put any radioactive waste or spent nuclear fuel in it or even allow DOE to begin transporting waste to it. Enactment of the joint resolution will only allow DOE to take the next step in the process laid out by the Nuclear Waste Policy Act and apply to the NRC for authorization to construct the repository at Yucca Mountain."); H.R. Rep. No. 107-425, at 7 (2002) ("In accordance with the Nuclear Waste Policy Act (NWPA), such approval would allow the Department of Energy (DOE) to apply for a license with the Nuclear Regulatory Commission to construct a nuclear waste storage facility on the approved site.").[8] That conclusion is even more strongly compelled now, in light of Congress's recent decision to provide funding to a Blue Ribbon Commission, whose explicit purpose is to propose "alternatives" for the disposal of high-level waste and spent nuclear fuel.

Even if there were any ambiguity on these points, the Secretary's interpretation of the NWPA would be entitled to deference. *See Chevron, U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984); *Gen. Elec. Uranium Mgmt. Corp. v. DOE*, 764 F.2d 896, 907 (D.C. Cir. 1985) (applying *Chevron* deference to uphold DOE's interpretation of the NWPA); *see also Skidmore v Swift Co.*, 323 U.S. 65 (1944); *Auer v. Robbins*, 519 U.S. 452 (1977); *Coeur*

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[8] *See also* 148 Cong. Rec. 7155 (2002) (Rep. Dingell) (stating that Yucca Mountain Site Approval Act "is just about a step in a process"); *id.* at 7166 (Rep. Norwood) ("The vote today does not lock us in forever and we are not committed forever to Yucca Mountain."); *id.* at 12340 (Sen. Crapo) ("[T]his debate is not about whether to open the Yucca Mountain facility so much as it is about allowing the process of permitting to begin to take place.").

Alaska, Inc. v. Southeastern Alaska Conservation Council, 129 S. Ct. 2458 (2009). Simply put, the text of the NWPA does not specify actions the Secretary can or must take once the application is filed. Accordingly, while some may disagree with the wisdom of the Secretary's underlying policy decision, the Secretary may fill this statutory "gap." The Secretary's interpretation is a reasonable one that should be given great weight and sustained. *See, e.g., Tennessee v. Herrington*, 806 F.2d 642, 653 (6th Cir. 1986) ("[W]e are mindful of the Supreme Court's statement in *Chevron, supra*, that: 'When a challenge to an agency construction of a statutory provision, fairly conceptualized, really centers on the wisdom of the agency's policy, rather than whether it is a reasonable choice within a gap left open by Congress, the challenge must fail.'").

B. No Conditions Are Necessary As to the Licensing Support Network

Finally, there is no reason to impose conditions relating to the Licensing Support Network ("LSN") as a term of withdrawal. As DOE's prior filings with this Board explain, DOE will, at a minimum, maintain the LSN throughout this proceeding, including any appeals, and then archive the LSN materials in accordance with the Federal Records Act and other relevant law. *See* Department of Energy's Answers to the Board's Questions at the January 27, 2010 Case Management Conference (filed Feb. 4, 2010); Department of Energy's Status Report on Its Archiving Plan (filed Feb. 19, 2010). Thus, DOE will retain the full LSN functionality throughout this proceeding, including appeal, and then follow well established legal requirements that already govern DOE's obligations regarding these documents. DOE is also considering whether sound public and fiscal policy, and the goal of preserving the knowledge gained both inside and outside of this proceeding, suggest going even further than those legal

requirements. There is thus no need for this Board to impose additional conditions concerning the preservation of records.

* * *

DOE counsel has communicated with counsel for the other parties commencing on February 24, 2010, in an effort to resolve any issues raised by them prior to filing this Motion, per 10 C.F.R. § 2.323(b). The State of Nevada and the State of California have stated that they agree with the relief requested here. The Nuclear Regulatory Commission Staff has stated that it takes no position at this time. The Nuclear Energy Institute has stated that it does not consent to the relief requested and will file its position in a response. All other parties that have responded have stated that they reserve their positions until they see the final text of the motion.[9]

[9] These parties include: Clark County, Eureka County, Four Counties (Esmeralda, Lavender, Churchill, Mineral), Inyo County, Lincoln County, Native Community Action Council, Nye County, Timbisha Shoshone Tribal Group, White Pine County.

Respectfully submitted,

U.S. DEPARTMENT OF ENERGY
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March 3, 2010

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Atomic Safety and Licensing Board

Before Administrative Judges:
Thomas S. Moore, Chairman
Paul S. Ryerson
Richard E. Wardwell

In the Matter of	)	Docket No. 63-001
U.S. DEPARTMENT OF ENERGY	)	ASLBP No. 09-892-HLW-CAB04
(High-Level Waste Repository)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the **U.S. DEPARTMENT OF ENERGY'S MOTION TO WITHDRAW** have been served on the following persons on this 3rd day of March 2010 through the Nuclear Regulatory Commission's Electronic Information Exchange.

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EXHIBIT 5

SOUTHERN CALIFORNIA EDISON®
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NEWS

Media Contact: Maureen Brown, (626) 302-2255

SCE Selects Robust Underground System to Store San Onofre Used Nuclear Fuel

ROSEMEAD, Calif., Dec. 11, 2014 — Southern California Edison (SCE) has selected Holtec International to expand the San Onofre nuclear plant's storage of used nuclear fuel in a robust underground facility.

The contract with Holtec represents a major step in the decommissioning of the nuclear plant. It sets the stage to transfer San Onofre's used fuel from steel-lined concrete storage pools to steel-and-concrete-encased canisters, with a goal of completing the work by mid-2019.

"After reviewing leading designs with the San Onofre Community Engagement Panel, we concluded this underground design is best suited to safely and securely store used nuclear fuel at San Onofre until the federal government removes the fuel from site, as required," said Chris Thompson, SCE vice president of Decommissioning. "Our decision to move expeditiously to transfer the fuel also reflects feedback from community leaders who prefer dry storage of used nuclear fuel."

Thompson noted the robust Holtec design exceeds California earthquake requirements and protects against hazards such as water, fire or tsunamis.

"I especially want to thank the Community Engagement Panel for its thoughtful questions and enormous time commitment during SCE's evaluation," said Thompson, noting that SCE ultimately focused on cask designs licensed by the Nuclear Regulatory Commission for both storage *and* transport of used nuclear fuel.

While dry storage of nuclear fuel is a proven technology used for almost three decades in the United States, Thompson said SCE will go beyond industry practices by partnering with the Electric Power Research Institute to develop new inspection techniques to monitor cask integrity.

Holtec's HI-STORM UMAX underground storage system features corrosion-resistant, stainless-steel fuel canisters topped with a 24,000-pound steel and concrete lid. The canisters will be encased in a concrete monolith. Holtec is a global supplier and has nuclear fuel storage systems at two other California locations, Humboldt Bay and Diablo Canyon. More information is available in this fact sheet.

Thompson said engineering work begins immediately, followed by fabrication of canisters. Completion of the dry storage project facilitates major dismantlement work SCE plans to complete within 20 years.

SCE announced in June 2013 that it would retire San Onofre Units 2 and 3, and begin preparations to decommission the facility. SCE has established core principles of safety, stewardship and engagement to guide decommissioning. For more information about SCE, visit www.songscommunity.com.

About Southern California Edison
An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal and Southern California.

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EXHIBIT 6

San Onofre Nuclear Waste Problems

Tom English, Ph.D., Samuel Lawrence Foundation
Subrata Chakraborty, Ph.D., UCSD, Dept. of Chemistry and Biochemistry
Rear Admiral Len Hering Sr. USN (ret)

January 2019

INTRODUCTION

In August 2018, a near-accident during the loading of nuclear waste into dry storage triggered a federal investigation and brought new urgency to the debate of how best to store some of the most dangerous waste known to humankind – spent nuclear fuel. The San Onofre Nuclear Generating Station (S.O.N.G.S.) closed in 2012 after a number of serious failures. Since then, Southern California Edison and its contractor, Holtec International, built a concrete storage vault to hold 3.6 million pounds of nuclear waste in dry storage. That vault is footsteps from the rising Pacific Ocean. In our brief report, we explore the fatal flaws of this location and recommend moving the storage facility to a technically defensible storage facility at a significantly higher elevation with distance from the ocean. We address the inadequacy of the equipment used to move and contain the nuclear waste material. We explore the gouging that occurs when stainless steel canisters are lowered into the storage vault and how gouging compromises the integrity of the containers. Finally, we examine management practices at San Onofre and an apparent lack of supervision, training and protocols. The examination of the perils of S.O.N.G.S. Independent Spent Fuel Storage Installations' poor location, poor technology and poor management, presents an urgent situation for regulators to: order Edison to permanently stop the loading of canisters into dry storage, require Edison to store the waste in canisters that may be inspected, and secure an independent analysis and risk assessment of canister loading procedure.

RATIONALE

Most serious of the issues facing the interim storage of nuclear waste at S.O.N.G.S. include the gouging damage to fully-loaded steel canisters upon downloading into the storage vault. These 54-ton thin-walled steel canisters are loaded with nuclear waste in wet storage – spent fuel pools – and are transported to the on-site concrete storage vault, adjacent to the reactor domes. With the Brinell hardness scale calculations our team demonstrates the depth and width of canister gouges upon downloading into the storage system. The current downloading procedure and on-site storage configuration provides the factors necessary to create gouges in the external steel walls of the canisters: operators have no visibility of the canister during downloading and precise adjustments to canister orientation cannot be made. These gouges remain undetected and unrepaired due to the lack of thorough inspection and monitoring at

the San Onofre Independent Spent Fuel Storage Installations (ISFSIs). The preliminary findings are found in this report.

1. POOR LOCATION

Today, two separate Independent Spent Fuel Storage Installations (ISFSIs) exist at San Onofre. The newest, built by Holtec, is located about 100 feet from the Pacific Ocean on the 85-acre grounds of S.O.N.G.S. The property is part of Marine Corps Base Camp Pendleton and is owned by the Department of the Navy. Two of the nation's busiest transportation corridors -- Interstate 5 and the Los Angeles-San Diego-San Luis Obispo Rail Line -- flank the site. The ISFSIs are clearly visible in Google Earth images and in numerous published photographs. The high accessibility and visibility of the site leaves it extremely vulnerable to an act of malfeasance.

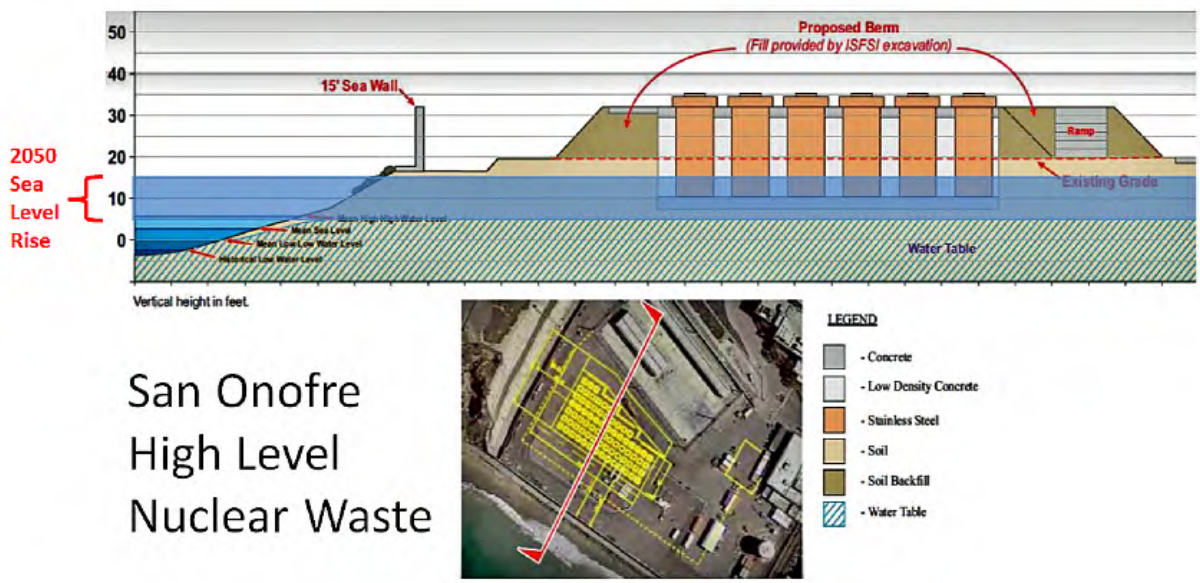

Figure 1. Independent Spent Fuel Storage Installations and Storage Vault.

Forces of nature, exacerbated by sea-level rise, carry further risks. Frequent high humidity and coastal fog make the metal at the site susceptible to short-term corrosion and stress-induced corrosion cracking. Also located at this site is a second, older ISFSI, which contains 51 thin-walled steel canisters that are up to 15 years old.

Numerous reports show that mean high tide level is about 18 inches below the base of the newer, oceanfront ISFSI, which was designed by Holtec. Since this is the mean height, the sea level frequently exceeds this height. Hence, it is likely the present ground water table will leach into the storage vault and result in at least damp storage. Further sea level rise due to climate change will make this problem far worse.

Dr. James Hansen, who managed NASA's climate change program for about 25 years, predicts sea levels could rise up to 10 feet during the next 50 years. At San Onofre, this would cause the bottom seven feet of the Holtec nuclear storage canisters to be submerged in seawater, unintentionally resulting in wet storage. This would invite a crisis similar to that of Fukushima, where spent fuel was exposed to moisture.

A second estimate appears in a comprehensive report by the Working Group of the California Ocean Protection Council Science Advisory Team. Published in 2017, the report shows 75% likelihood sea levels will rise by two feet by 2100. Either of these scenarios envisions that a major portion of the nuclear storage canisters as San Onofre would be submerged in seawater. The combination of the effects of sea-level rise and ground water inundation at the current location would change the Holtec ISFSI to wet storage site, for which it was not designed. Hence, little if anything would be accomplished by moving the waste from the spent-fuel pool to the dry storage ISFSI. The dangers would not be decreased. If anything, the inability to adequately measure and mitigate the impacts of corrosion on the underground nuclear canisters would lead to a significant increase in risk.

All of this can be avoided. If the nuclear waste at the two ISFSIs is transferred into thick-walled casks and then moved to a technically defensible storage facility at higher ground, the problems of ocean water and ground water intrusion can be avoided. As an added benefit, the waste would be easier to secure from an act of malfeasance.

2. POOR TECHNOLOGY

In California, the storage tanks at gas stations must be double-walled; painful experience has shown that single-walled containers can leak gasoline into the groundwater system. With a double-walled fuel tank, if a leak occurs it can be detected and the storage container can be repaired or replaced before any gasoline is released. At San Onofre, we certainly should expect that some kind of leak prevention system would be in place to contain extremely toxic high-level radioactive waste. Additionally, the canisters should be able to be monitored and inspected. The thin-walled canisters at the San Onofre ISFSIs cannot be adequately monitored or inspected. Regulators and Holtec officials have stated that the canisters cannot be inspected from the inside or the outside for cracks or other degradation and that, even if damage could be identified, it would be impossible to fix.

To illustrate the importance of adequate monitoring, we analyze a scenario in which one vent of a canister clogs. We refer to a Holtec non-proprietary safety analysis report[1] that calculates a temperature rise to about 90% of the maximum permissible limit (MPL) in 24 hours. This infers that within the next 12 hours the system will exceed the MPL rating and lead to a meltdown[2].

[1] Table 4.I.9, page 1050, Holtec International Final Safety Analysis Report for the HI-STORM 100 Cask System. USNRC Docket No.: 72-1014, Holtec Report No.: HI-2002444.

[2] S. Alyokhina, Thermal analysis of certain accident conditions of dry spent nuclear fuel storage, Nuclear Engineering and Technology 50 (2018) 717-723.

Through our own statistical analysis,[3] we prove that if the probability of clogging one of the vents during an event is 1%, then the chance that one of the 146 total vents (two vents on each of 73 canisters) will clog in such an event is 78%. This chance reduces to 53% if we reduce the probability of occurrence to .5% from 1%. Tsunamis followed by clogging are dependent events and thus the combined chance of such an event is about 11% during a 30-year period. The sea level rise, the rise of tide levels and the associated rise in the coastal aquifer are all interlinked, as discussed previously. These climate-related phenomena could cause serious damage to the ISFSIs. Therefore, close monitoring and the use of proven thick-walled cask technology for all nuclear waste storage containers is not only necessary but urgent. A mishap could imperil the lives and livelihoods of more than 8 million people who live within 50 miles of the ISFSIs.

2.1 NEAR MISS EVENT

David Fritch, an industrial safety inspector turned whistleblower, remembers August 3, 2018, as a bad day. Fritch worked at San Onofre during a loading failure that left a fully-loaded 54-ton canister of high-level radioactive waste stuck on the lip of a guide ring. Above the 17-foot-tall canister, the slings that attached it to the behemoth loading rig had gone slack.

The canister was, “hanging by about a quarter inch,” Fritch told attendees of the community engagement panel on August 9. “It’s a bad day. That happened, and you haven’t heard about it, and that’s not right. What we have is a canister that could have fallen 18 feet.”

Subsequent investigations revealed that the operators and managers could not see Canister No. 29 as it was being loaded into the storage cavity and became stuck for nearly an hour.

Since the near-accident, regulators have halted further loading of canisters into the seaside storage vault and researchers have explored what could have happened if Canister No. 29 had fallen.

Our own research explores the basic physics of a fully-loaded 54-ton canister in free fall to extrapolate the upper energy involved in the initial impact.

For example, the falling canister could hit the steel-lined concrete floor of the nuclear waste storage facility with explosive energy greater than that of several large sticks of dynamite. The resultant damage to the canister could cause a large radiation release.
At point of contact at the bottom of the storage cavity, damage to the concrete and metal structure could ruin the cooling system. The damage to the concrete would equal that of a fully-loaded 18-wheeler truck, with a gross weight of 80,000 pounds, crashing into reinforced concrete at 23 miles per hour. Our preliminary calculations show the combination of the weight and velocity of the dropped canister exceeds the ISFSIs’ “design criteria for tornado missiles,” by a factor of 4. Future experiments should include drop tests of the actual canisters with non-

[3] Chakraborty and English, 2019, ES&H Risk Estimation from “Interim Storage” of SNF at the Beach: The San Onofre NPP, WM2019 Conference, March 3-7, 2019, Phoenix, Arizona, USA (under review).

radioactive loads that simulate the weight of the spent fuel assemblies and fuel baskets to determine what would happen to the actual canisters.

Southern California Edison is set to move 73 canisters into the seaside storage vault and, at the time of publication, has moved 29. Each nuclear storage canister contains 37 spent fuel assemblies, which generate enormous amounts of heat. The systems are cooled by a simple air duct system, which could have been blocked by the damage caused by the canister's fall. If that had happened, great quantities of water would have been needed to cool the reaction and prevent or control a meltdown. The enveloping water would instantly become radioactive steam, as we saw at Fukushima. In the heavily-populated area surrounding San Onofre, however, radioactive steam could prompt the evacuation of millions of people. What's more, since both the canister and the surrounding structure could be badly damaged, there would be no available way to pull the damaged canister from the storage cavity.

Nuclear Regulatory Commission (NRC) computer simulations show what happens when a nuclear storage canister with slightly thinner walls[4] drops from 19 feet. In the test, a canister falls from a transfer cask onto a storage pedestal. The canister failure rate was 28%. Similar calculations must be performed at San Onofre to determine if that storage system has a similar probability of canister failure. At 28%, that is more than a one-in-four chance of catastrophic failure. Would you fly on an airplane with those odds? Our analysis alone should place the NRC, policymakers and Edison on alert. A more substantial analysis must be completed to examine the potential damage that can be caused by a falling, fully-loaded 54-ton nuclear storage canister.

Continued loading of the nuclear waste into canisters threatens the lives and livelihood of more than 8 million people. Software and computer resources are available by which estimates can be made of the impacts of a dropped canister on both the reinforced concrete and the canister walls. The NRC-approved Holtec technical specifications state that a canister drop of more than 11 inches requires the contents of the canister to be inspected for damage. This specification assumed the canister was in a transfer cask. The impact of an un-casked canister was never analyzed because Holtec and the NRC assumed it could never happen, citing triple-redundancy of the fuel transfer system. But a subsequent NRC inspection revealed that on August 3rd, all three components of this system simultaneously failed. Only the accidental snag of a quarter-inch of the 54-ton canister on the lip of the guide ring prevented a catastrophe.

Our research suggests the entire storage system may need to be redesigned to reduce the probability of canister failure to levels that are acceptable in such a highly-populated area.

[4] Pg. 4-24 Table 12, NUREG-1864 - A Pilot Probabilistic Risk Assessment of a Dry Cask Storage System at a Nuclear Power Plant, March 2007, A. Malliakos, NRC Project Manager

RESULTS

2.2 GOUGES IN DROPPED CANISTER

In their 2007 report, the NRC's analysts did not consider the impact of gouges on the strength of canister walls. There was no need, the analysts and a Holtec official said, as gouges were not important to the system under examination. We disagree. A detailed analysis of gouging is necessary to properly evaluate the damage to Canister No. 29 during the botched loading and to every other canister loaded into the ISFSI.

We established preliminary results of such an analysis using the Brinell hardness scale approach to estimate the depth and width of expected gouges in 316 stainless steel, of which the Holtec canisters at San Onofre is made.

While the canister is stuck, the guide ring gouges the bottom of the canister.

As the canister drops it is gouged on two sides by a combination of the guide ring, the storage cavity wall and the inner diameter of the transfer cask. This gouging absorbs some of the kinetic energy of the canister.

When the canister smashes into the bottom of the cavity, the kinetic energy and momentum from the fall will be dissipated by damage to:

- the ISFSI;
- the canister; and
- the contents of the canister.

The formation process of gouges will exert a force on the canister. This is the force, P, shown in Figure 2.

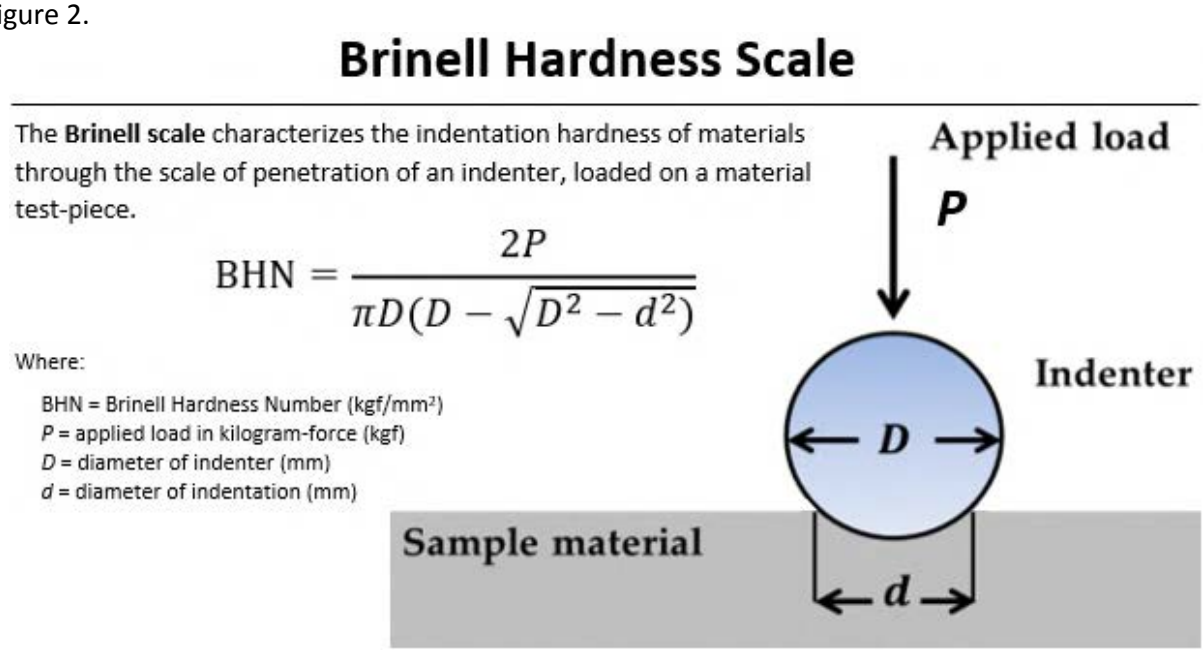

Figure 2. Brinell hardness scale calculation. Credit: *The Samuel Lawrence Foundation*.

In Figure 3, the width of a gouge is shown in relationship to the canister's weight. The expected range of gouge widths is shown in Figure 3. A variety of indenter widths are used as a surrogate for the gouging. The gouging widths range from 2 mm to 16 mm. This is highly significant, since the thickness of the nuclear canisters is 5/8", which is close to 16 mm. We recommend that tests be performed on actual canisters to experimentally determine the accuracy of these predictions.

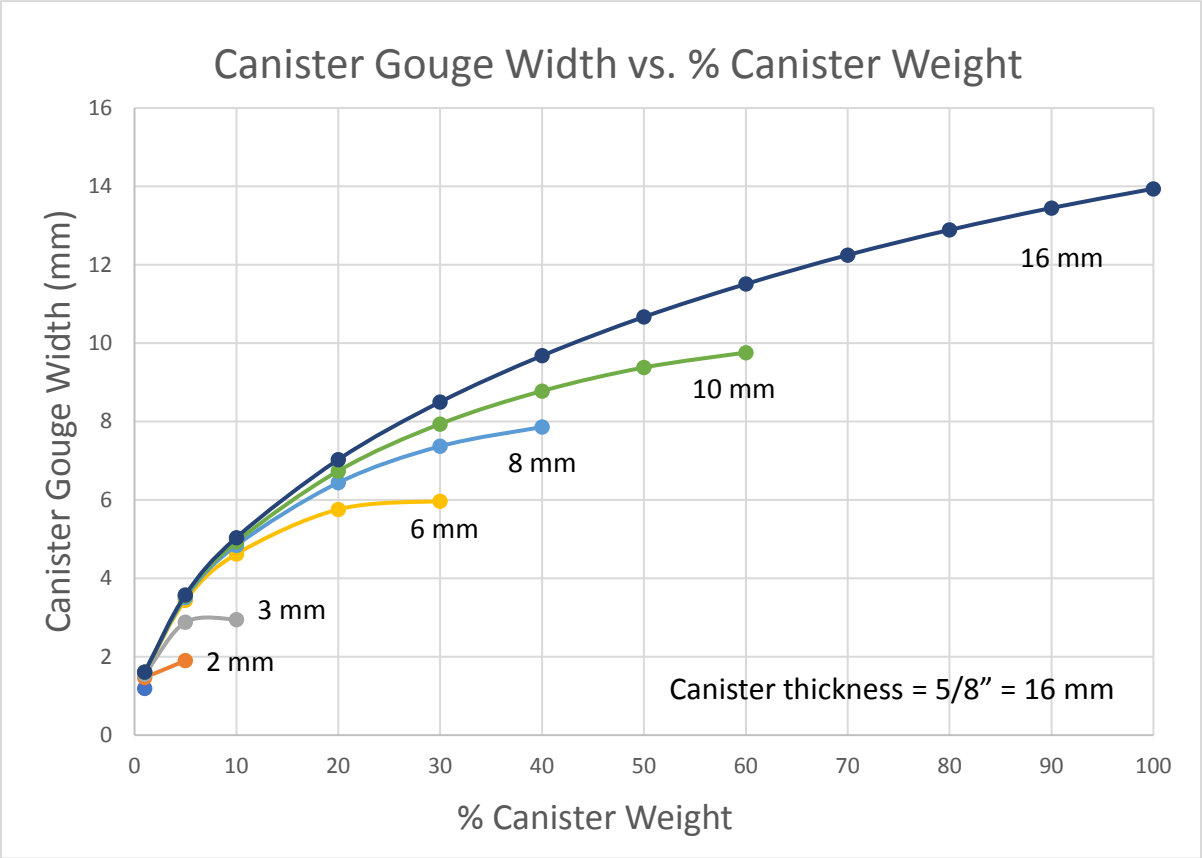

Figure 3. Calculated penetration width of gouge as a function of load for different intender diameter. The hardness number in Brinell scale for stainless steel 316 (BHN) is 217 kgf/mm^2. Saturated zone is eliminated.

The expected range of gouge depths is shown in Figure 4. A variety of indenter depths are used as a surrogate for the gouging. The gouging depths expected to be found range from 1 mm to 4.5 mm. This is highly significant, since 4.5 mm is 28% of the thickness of the nuclear storage canister.

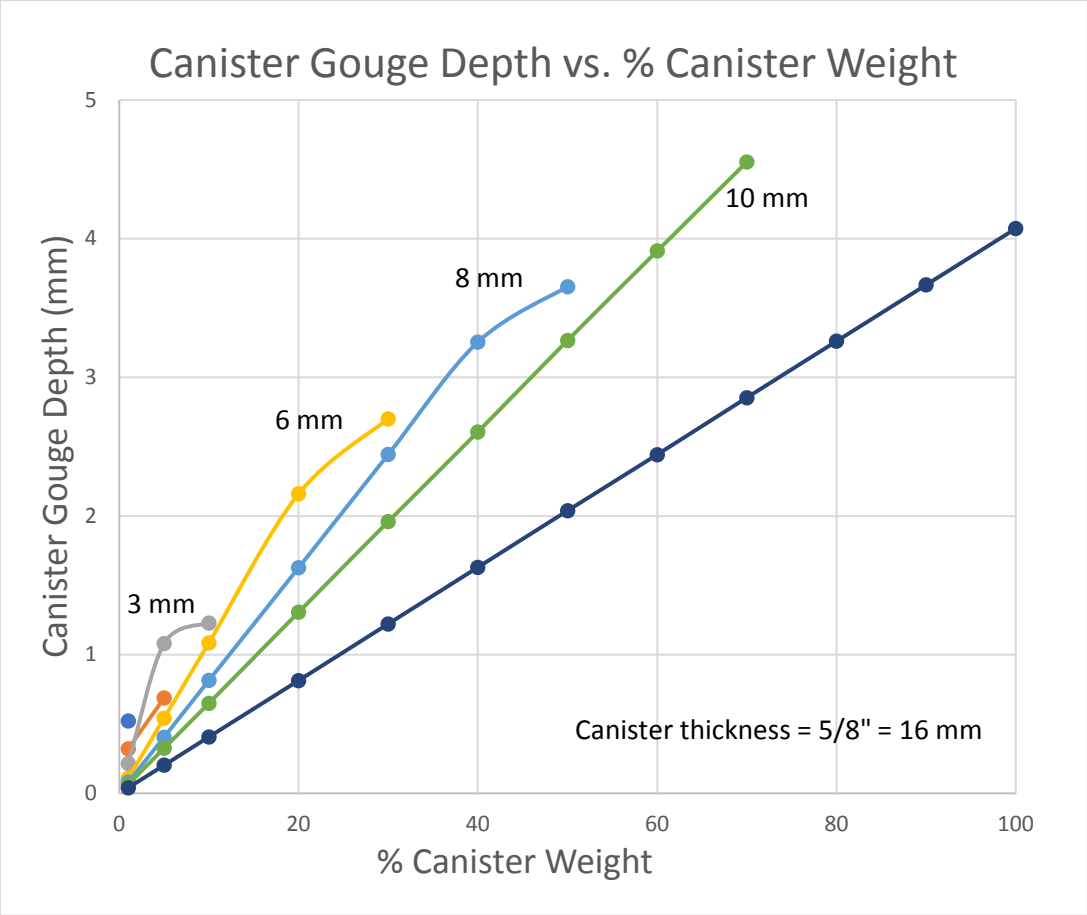

Figure 4. Calculated penetration depth of gouge as a function of load for different intender diameter. The hardness number in Brinell scale for stainless steel 316 (BHN) is 217 kgf/mm^2.

2.3 GOUGES DURING ROUTINE LOADING

Extensive gouging will also occur during routine loading of the nuclear storage canister into the storage cavity. By moving the Vertical Cask Transporter, shown in Figure 5, crude adjustments can be made to the alignment of the canister as it is lowered into the storage cavity. The bulky, tank-like machine travels on steel treads, like those found on earth-moving or military equipment. The transporter is not equipped to make the fine adjustments required to insert the nuclear storage canister into the narrow spacing of the storage cavity without banging the canister against the guide ring. This banging gouges the canister and causes the canister to move side-to-side, similar to a pendulum. An Edison official has referred to this process as "jiggling." This jiggling process continues for 15 to 30 minutes as the canister is lowered to the bottom of the storage cavity. Each "jiggle" causes the type of gouging shown in Figure 3 and

Figure 4. We expect that this routine loading process produces a multitude of gouges that significantly damage the canister walls, rendering them unsuitable for storage of nuclear waste.

Figure 5. Vertical Cask Transporter during downloading and alignment of a canister. Credit: *San Onofre Special Inspection Webinar Presentation (NRC)*.

We strongly recommend that a sampling of the canisters previously lowered into the storage vault be removed and inspected so the extent of gouging can be experimentally determined. We expect the damage will be so severe that the current ISFSI will need to be replaced.

3. POOR MANAGEMENT

During the late 1970s and early 1980s, Rear Admiral Len Hering, USN (ret) served as a Nuclear Weapons Safety Officer, Handling Officer and Surety Officer. Admiral Hering provides the following assessment of management practices at the S.O.N.G.S. ISFSI.

When it comes to the handling and movement of nuclear material, you would expect that only those specifically qualified and trained for such an important task would be deployed to ensure the safe movement of that material. In the Department of Defense (DOD), strict requirements are in place to make sure this very dangerous material is properly handled, transported and stowed.

The DOD and Navy programs were created and built to make certain nuclear material was secure, safely handled and accounted for. Every person who has any contact with nuclear material is required to have a security clearance. A “two-person rule” is in effect at all times. Personnel at all levels perform countless hours of training, obtain certifications of qualification, and complete rigorous inspection and training events to both prove and assure their proficiency in performing the job they are assigned. All of this is all done before anyone is permitted to even gaze upon a real weapon.

Handling gear and all aspects of the evolution are vigilantly maintained, inspected, weight-tested and inspected again. Cranes and dollies or hoist equipment are tested, placed under extreme loading conditions and prepared for specific tasks. Nothing goes untested. Nothing. We leave nothing to chance and we never hypothetically presume. If it isn’t tested and proven, it isn’t done with the actual material in question.

Ashore, and specifically at S.O.N.G.S, I find that virtually none of the protocols that should be expected for the safe handling of this dangerous material are present. I find that personnel and companies are being hired virtually off the street, no specific qualification standards are present or for that matter even required, training is not specific to the risks of the material involved, and there is no fully-qualified and certified team assembled for this highly-critical operation. They have not been required to conduct dry runs to ensure handling teams are proficient and, more importantly, they have never trained specifically to be ready to execute emergency procedures should the unexpected occur. The manuals are not on site, nor are they being followed to step a team through the evolution of moving the nuclear waste. Team leaders have no specific handling qualifications or training. Even the industrial safety inspectors are not specifically nuclear-certified but are general industrial specialists. No manuals are available for procedural review and, by their own admission, the required number of safety officials are often absent during movement of the nuclear storage canisters. In the Navy, if a near-accident such as the one at S.O.N.G.S is uncovered, the Commanding Officer, Weapons Officer -- and anyone else with a significant position on the team -- are relieved. The ship is then ordered to stand-down while a team of experts off-loads its cargo.

The widely reported incident in which a 54-ton, thin-walled container nearly fell 18 feet while it was being lowered into its silo rocked me to the core. What made things worse was narrative in a follow-up report that stated the canister was left suspended for nearly an hour, held up by a mere guide ring installed in the silo, cables slack and operators clueless. There is no doubt that this incident occurred because those on-scene were completely unqualified, unprepared, untrained and incompetent. This very dangerous operation was being performed as if this crew were moving a simple stack of wood around a construction site when, in actuality, the crew was conducting one of the most dangerous operations in the industrial sector. No one was relieved, fired or held accountable. The investigation being conducted is flawed in that those responsible for this deplorable safety environment are the same people who will feed findings to the investigation.

The handling of nuclear waste at San Onofre and other sites across our country should scare every single American. We have a regulatory agency that has failed to make sure the most basic safety precautions are being applied to one of the most dangerous industrial evolutions of our time. The number of waivers being issued where safety is of concern is staggering.

In the DOD, the reason why there were and continue to be no significant accidents with the handling of nuclear material is because there are no waivers and there are no quick wins. Workers are fully qualified, inspected and certified to handle this very dangerous material. In this case, there is no room for error. One mistake is too many. It is my professional opinion that we need to hit the reset button before a disaster of unparalleled portion occurs.

CONCLUSION

The nuclear waste at San Onofre requires a much better storage configuration and must be moved to a technically defensible storage facility to reduce threats. From a security standpoint, the waste should be moved further away from major transportation corridors. The thin-walled nuclear waste storage canisters are at risk of failure due to gouging when downloaded into the seaside storage vault. Once lowered into the storage system, the canisters cannot be thoroughly inspected, monitored or repaired. A near-accident on August 3rd demonstrated that safety protocols are lacking, and that further study is needed to understand the consequences of dropping a fully-loaded 54-ton canister of nuclear waste. The incident revealed that the loading equipment is imprecise and revealed a pattern of mismanagement in canister loading procedure. A complete analysis of canister loading procedure and comprehensive risk assessment must be conducted by an independent party with absolute transparency. If an accident, natural disaster, negligence, or an act of terrorism were to cause a large-scale release of radiation, the health and safety of 8.4 million people within a 50-mile radius would be put at risk. To secure the nuclear waste properly, we recommend a permanent stop to the loading of nuclear storage canisters into the seaside storage vault, placing spent fuel into reliable canisters that can be monitored, inspected and repaired, and moving these canisters to an acceptable storage facility at a significantly higher elevation.

ACKNOWLEDGEMENTS

We thank UCSD Departments of Chemistry and Biochemistry and The Samuel Lawrence Foundation. For more information visit www.samuellawrencefoundation.org/nuclear-energy.

EXHIBIT 7

EXHIBIT 28

ARTICLE XII.
CONTRACTOR'S WARRANTIES

12.1 WARRANTIES.

(a) Contractor warrants to Company that all Equipment shall be (i) new and of good quality; (ii) free from improper workmanship and Defects; (iii) conform to all applicable requirements of all Applicable Laws and all Applicable Permits; and (iv) be fit for Company's use in the nuclear power industry for the intended purpose. If Contractor accepts the Existing Canisters for use, Contractor warrants that the Existing Canisters shall be free from Defects or improper workmanship to the extent caused by or due to Contractor's acts or omissions.

(b) Contractor warrants to Company that the Work will be performed in a good and workmanlike manner, and that the Work will: (i) conform to and be designed, engineered and constructed in accordance with the Drawings, Scope of Work, all Applicable Laws and Applicable Permits and other terms of the Contract Documents; (ii) conform with, and be designed and engineered according to professional standards and skill, expertise and diligence of design professionals regularly involved in decommissioning projects similar to the Project, and comply with the requirements of the relevant Government Authorities, including the NRC; (iii) be suitable for the use as set forth in the Technical Specification; (iv) be compatible with the spent fuel pools for Units 2 and 3, spent fuel, fuel handling building, the existing ISFSI, Jobsite, and the SONGS site conditions; (v) contain the Equipment, supplies and materials described in the Scope of Work, all installed in accord with the applicable Contract Documents; (vi) in the case of Apparatus be designed, engineered, licensed, fabricated and manufactured using appropriate and approved processes, procedures and materials and to comply with and satisfy all the terms of the Certificate of Compliance issued by the NRC to Contractor as modified or amended as contemplated herein; (vii) in the case of Drawings or documents required hereunder, accurately and completely present information required to be included therein or necessary to avoid misunderstandings of the included content; and (viii) at such times as the NRC issues or amends a Certificate of Compliance with respect to an Apparatus or Existing Canisters, as applicable, the Apparatus or such Existing Canister specifically approved by the NRC to perform functions required by regulation as described in such Certificate of Compliance shall perform its required functions set forth in such Certificate.

(c) Contractor warrants to Company that all of the documents prepared by Contractor for submittal to a Government Authority for review and approval shall be prepared in full compliance with Applicable Laws and in form and substance such that Company shall not be

required to modify or revise such documents due to a failure to include any required information, inaccuracies or the use of inappropriate forms or formats.

(d) Contractor warrants to Company that none of the Work, including the Equipment (but not including the Existing Canisters), the Drawings, Final Plans and the design, engineering and other services rendered by Contractor hereunder, nor the use or ownership thereof by Company in accordance with the licenses granted hereunder, infringes, violates or constitutes a misappropriation of any trade secrets, proprietary rights, intellectual property rights, patents, copyrights or trademarks.

(e) Except as expressly stated herein to the contrary, Contractor warrants that it shall remedy, in accordance with Section 12.2, any Defects in the Work due to faulty design, materials or workmanship which appear within a period commencing upon the date of ISFSI Scope Completion and continuing for the applicable period following the ISFSI Scope Completion Date (as such period may be extended in accordance with the terms hereof, the "Warranty Period"), as follows:

(i) with respect to the MPC-37 canisters, twenty five (25) years;

(ii) with respect to Contractor's Work on Existing Canisters used to store non-fuel waste from the spent fuel pools, twenty five (25) years; provided that the Warranty Period with respect to such Work shall commence on the date that the last of the Existing Canisters containing non-fuel waste are loaded on the ISFSI during Post-ISFSI Scope Work and the related Milestone has been completed;

(iii) with respect to the Contractor's Work on Existing Canisters used to store greater than class "C" radioactive waste from reactor vessel segmentation in the Post-ISFSI Scope Work, twenty five (25) years; provided that the Warranty Period with respect to such Work shall commence on the Final Acceptance Date;

(iv) with respect to the HI-STORM UMAX System, ten (10) years;

(v) with respect to any other Work that is required to be completed in order to achieve ISFSI Scope Completion, including Contractor's Work on any newly assembled AHSM-HS modules that are used by Contractor in the performance of the Work, two (2) years; and

(vi) with respect to any other Work that is completed after the ISFSI Scope Completion Date, two (2) years from the Final Acceptance Date.

Contractor shall bear all costs of corrections and repairs during the Warranty Period. The provisions of this Section 12.1 apply to Work performed by Subcontractors as well as Work performed directly by Contractor. The provisions of this Article XII do not apply to corrective work caused by the acts or omissions of Company or any separate contractor of Company. If and in the event Company notifies Contractor of a Defect within the Warranty Period, Contractor, at Contractor's expense, shall perform all Work necessary to remedy the Defect, and the repair or replacement Work performed by Contractor to accomplish that purpose shall be subject to an additional express warranty from the date the repair or replacement is completed which shall continue for a duration equivalent to the original Warranty Period.

(f) Notwithstanding anything to the contrary herein, the warranties set forth in this Section 12.1 shall not apply with respect to any claims to the extent arising from (i) any use of the Work or components thereof by Company that exceeds the requirements or recommendations in Contractor's operation and maintenance manuals; (ii) the failure of any Equipment or Work to be maintained in accordance with Contractor's written instructions; or (iii) the modification of any Equipment or Work without Contractor's written consent.

(g) THE WARRANTIES OF CONTRACTOR SET FORTH IN THIS AGREEMENT ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND ALL WARRANTIES ARISING FROM COURSE OF DEALING AND USAGE OF TRADE). The foregoing sentence is not intended to disclaim any other obligations of Contractor set forth herein.

12.2 REPAIR OF NONCONFORMING WORK.

(a) If any of the Work is found to contain Defects, or Contractor is otherwise in breach of any of the warranties set forth in Section 12.1 within the Warranty Period, Contractor shall at its sole cost and expense and without reimbursement hereunder correct, reperform, repair or replace such Defect or otherwise cure such breach as promptly as practicable upon being given notice thereof. Subject to Section 12.3, Company shall give notice to Contractor within two (2) Business Days of discovery of such Defect. Company shall provide Contractor with reasonable access to the Project in order to perform such corrective Work and the Parties shall schedule such corrections or replacements as necessary so as to minimize disruptions to any on-going activities at SONGS. Contractor shall bear all costs and expenses associated with correcting any Defect or breach of warranty, including necessary disassembly, transportation, reassembly and retesting, as well as reworking, repair or replacement of such Work, disassembly and reassembly of piping, ducts, machinery, Equipment or other Work as necessary to give access to improper, defective or non-conforming Work and correction, removal or repair of any damage to other work or property that arises from the Defect. If Contractor is obligated to repair, replace or renew any Equipment, item or portion of the Work hereunder, Contractor will undertake a technical analysis of the problem and correct the "root cause" unless Contractor can demonstrate to Company's satisfaction that there is not a risk of the reoccurrence of such problem. Contractor's obligations under this Section 12.2 shall not be impaired or otherwise adversely affected by any actual or possible legal obligation or duty of any Subcontractor to Contractor or Company concerning any Defect or breach of warranty.

(b) If (i) Contractor fails to complete or commence with due diligence to complete the correction of any Defect or cure of any breach of warranty as required herein within twenty (20) days after receipt of written request from Company to perform such obligations, or (ii) a Defect cannot be corrected within twenty (20) days and Contractor fails to provide a correction plan within five (5) Business Days after receipt of Company's written request to perform such obligations or thereafter fails to implement the plan with due diligence following Company's approval of the plan, then Company may correct or cause to be corrected such Defect or cure such breach of warranty and Contractor shall be liable for all reasonable costs, charges, and expenses incurred by Company in connection therewith (including reasonable and necessary consultants' fees), and Contractor shall, within fifteen (15) days after request therefore, pay to

Company an amount equal to such reasonable costs, charges, and expenses. Any such request by Company shall be accompanied by proper documentation evidencing such reasonable costs, charges and expenses. Any amounts not paid when due shall accrue interest at the Reference Rate (established as of the first day of the month in which payment is due) from the date due until paid. Company and Contractor agree to treat (and shall cause each of their respective Affiliates to treat) any payment made to Company pursuant to this Section 12.2(b) as an adjustment to the Contract Price unless a final determination (which shall include execution of an Internal Revenue Service Form 870-AD or successor form) provides otherwise.

(c) If, during the Warranty Period, Contractor shall change, repair or replace any major Equipment item or component, Company, in its reasonable discretion and consistent with Applicable Laws or Applicable Permits, may require Contractor to assist Company in conducting any test required by any Applicable Law or Applicable Permit with respect to the affected Equipment; provided, however, in connection with any such test, appropriate allowance with respect to the performance of such Equipment shall be made for the fact that such Equipment may have operated prior thereto. If after running such test, the results indicate Contractor has not fulfilled any of its warranty obligations and there is a degradation in the performance of the Project and such degradation results from the warranty Work performed in accordance with this Article XII, then Contractor shall repair, correct or replace such affected Equipment and assist Company in re-running such test until the results no longer indicate a degradation in the performance of the Project resulting from the warranty Work performed in accordance with this Article XII. If Contractor cannot reasonably correct such degraded warranted performance condition then the Parties shall negotiate an equitable settlement of Company's damages based on the amount and scope of such deficient warranted performance, or if the amount of such deficient warranted performance is considered by Company to be a material breach of the terms of this Agreement, then Company may declare such breach to be a Contractor Event of Default pursuant to Section 15.1.

12.3 REPAIRS AND TESTING BY COMPANY.

During the Warranty Period, in the event of an emergency and if, in the reasonable judgment of Company, the delay that would result from giving notice to Contractor could cause serious loss or damage which could be prevented by immediate action, any action (including correction of Defects) may be taken by Company or a third party chosen by Company. Company shall give notice to Contractor within two (2) Business Days of discovery, and in the case of a Defect, the reasonable cost of correction shall be paid by Contractor. In the event such action is taken by Company, Contractor shall promptly respond within five (5) Business Days after correction efforts are implemented, and shall assist whenever and wherever possible in making the necessary corrections. All such warranties obtained shall be in addition to, and shall not alter the warranties of, Contractor. Upon Company's request, Contractor shall use all reasonable efforts to cause Subcontractors to honor warranties including filing suit to enforce same.

12.4 SUBCONTRACTORS. Contractor shall, for the protection of Contractor and Company, obtain from the Subcontractors such guarantees and warranties with respect to Work performed and Equipment supplied, used and installed hereunder as are reasonably obtainable, which guarantees and warranties shall equal or exceed those set forth in Section 12.1 and shall be made available and assignable to Company to the full extent of the terms thereof upon the expiration of Contractor's warranty hereunder. Company shall be an express third party

beneficiary of all such guarantees and warranties, provided such third party beneficiary rights shall not be effective unless this Agreement has been terminated. If available, Company may require Contractor to secure additional warranty or extended guarantee protection pursuant to a Change Order issued in accordance with the provisions of Article VI. Upon the earlier of the ISFSI Scope Completion Date or termination of this Agreement, Contractor shall deliver to Company copies of all relevant contracts providing for such guarantees and warranties.

12.5 CONDITIONS OF WARRANTIES. The warranties set forth in this Article XII are subject to the following conditions applicable to the item for which Company claims a breach of warranty exists:

(a) Company shall notify Contractor in writing of any Defect in the Work as soon as reasonably practicable after Company becomes aware of such Defect.

(b) Company shall have the right to continue to use the Equipment, including the Apparatus, as applicable, or any part thereof, which may require warranty correction or repair until such time as Company elects to remove such Equipment, or part thereof, as applicable, from service; provided, however, in such event, Company shall release Contractor from any additional claims for further defects or damage incurred as a result of such continued operation.

(c) Company shall use and maintain the Equipment, including the Apparatus, in accordance with the operation and maintenance procedures agreed upon by the Parties pursuant to this Agreement (these procedures shall be written by Contractor as part of Contractor's Work so as to integrate (where applicable) or replace and supersede (where not applicable) the operations and maintenance procedures required by the original manufacturer for the Existing Equipment and Existing Canisters such that Contractor may not assert that Company's failure to comply with any separate requirements from the existing manufacturer limits the warranty provided herein by Contractor).

(d) Completion of payments by Company shall not relieve Contractor of any of its warranty obligations.

12.6 ASSIGNMENT OF WARRANTIES. Contractor shall assign to Company or obtain for Company's benefit the manufacturer's warranties for all of the Equipment, including the Apparatus and other deliverables, which are provided in connection with the Work, but which are not manufactured by Contractor, including for Work performed under Section 12.3. Such assignment of warranties to Company must also allow Company to further assign such warranties.

12.7 SURVIVAL OF WARRANTIES. The provisions of this Article XII shall survive the expiration or termination of this Agreement.

EXHIBIT 8

NRC FORM 651
(10-2004)
10 CFR 72

U.S. NUCLEAR REGULATORY COMMISSION

CERTIFICATE OF COMPLIANCE FOR SPENT FUEL STORAGE CASKS

The U.S. Nuclear Regulatory Commission is issuing this Certificate of Compliance pursuant to Title 10 of the Code of Federal Regulations, Part 72, "Licensing Requirements for Independent Storage of Spent Nuclear Fuel and High-Level Radioactive Waste" (10 CFR Part 72). This certificate is issued in accordance with 10 CFR 72.238, certifying that the storage design and contents described below meet the applicable safety standards set forth in 10 CFR Part 72, Subpart L, and on the basis of the Final Safety Analysis Report (FSAR) of the cask design. This certificate is conditional upon fulfilling the requirements of 10 CFR Part 72, as applicable, and the conditions specified below.

Certificate No.	Effective Date	Expiration Date	Docket No.	Amendment No.	Amendment Effective Date	Package Identification No.
1040	TBD	TBD	72-1040	0		USA/72-1040

Issued To: (Name/Address)

Holtec International
Holtec Center
555 Lincoln Drive West
Marlton, NJ 08053

Safety Analysis Report Title

Holtec International
Final Safety Analysis Report for the
HI-STORM UMAX Canister Storage System

This certificate is conditioned upon fulfilling the requirements of 10 CFR Part 72, as applicable, the attached Appendix A (Technical Specifications) and Appendix B (Approved Contents and Design Features), and the conditions specified below:

APPROVED SPENT FUEL STORAGE CASK

Model No.: HI-STORM UMAX Canister Storage System

DESCRIPTION:

The HI-STORM UMAX Canister Storage System consists of the following components: (1) interchangeable multi-purpose canisters (MPCs), which contain the fuel; (2) underground Vertical Ventilated Modules (VVMs), which contains the MPCs during storage; and (3) a transfer cask (HI-TRAC VW), which contains the MPC during loading, unloading and transfer operations. The MPC stores up to 37 pressurized water reactor fuel assemblies or up to 89 boiling water reactor fuel assemblies.

The HI-STORM UMAX Canister Storage System is certified as described in the" UMAX" Final Safety Analysis Report (FSAR) supplemented by the information on the MPCs and transfer cask in the HI-STORM FW FSAR, and in the U. S. Nuclear Regulatory Commission's (NRC) Safety Evaluation Report (SER) accompanying the Certificate of Compliance (CoC).

The MPC is the confinement system for the stored fuel. It is a welded, cylindrical canister with a honeycombed fuel basket, a baseplate, a lid, a closure ring, and the canister shell. All MPC components that may come into contact with spent fuel pool water or the ambient environment are made entirely of stainless steel or passivated aluminum/aluminum alloys. The canister shell, baseplate, lid, vent and drain port cover plates, and closure ring are the main confinement boundary components. All confinement boundary components are made entirely of stainless steel. The honeycombed basket provides criticality control.

DESCRIPTION (continued)

There are two types of MPCs permitted for storage in HI-STORM UMAX VVM: the MPC-37 and MPC-89. The number suffix indicates the maximum number of fuel assemblies permitted to be loaded in the MPC. Both MPC models have the same external diameter.

The HI-TRAC VW transfer cask provides shielding and structural protection of the MPC during loading, unloading, and movement of the MPC from the cask loading area to the VVM. The transfer cask is a multi-walled (carbon steel/lead/carbon steel) cylindrical vessel with a neutron shield jacket attached to the exterior and a retractable bottom lid used during transfer operations.

The HI-STORM UMAX VVM utilizes a storage design identified as an air-cooled vault or caisson. The HI-STORM UMAX VVM relies on vertical ventilation instead of conduction through the fill material around the VVM, as it is essentially a below-grade storage cavity. Air inlets and an air outlet allow air to circulate naturally through the cavity to cool the MPC inside. The subterranean steel structure is seal welded to prevent ingress of any groundwater in the MPC storage cavity from the surrounding subgrade, and it is mounted on a stiff foundation. The surrounding subgrade and a top surface pad provide significant radiation shielding. A loaded MPC is stored within the HI-STORM UMAX VVM in a vertical orientation.

CONDITIONS

1. OPERATING PROCEDURES

Written operating procedures shall be prepared for handling, loading, movement, surveillance, and maintenance. The user's site-specific written operating procedures shall be consistent with the technical basis described in Chapter 9 of the FSAR.

2. ACCEPTANCE TESTS AND MAINTENANCE PROGRAM

Written acceptance tests and a maintenance program shall be prepared consistent with the technical basis described in Chapter 10 of the FSAR. At completion of welding the MPC shell to baseplate, an MPC confinement weld helium leak test shall be performed using a helium mass spectrometer. This test shall include the base metals of the MPC shell and baseplate. A helium leakage test shall also be performed on the base metal of the fabricated MPC lid. The confinement boundary welds leakage rate test shall be performed in accordance with ANSI N14.5 to "leaktight" criterion. If a leakage rate exceeding the acceptance criteria is detected, then the area of leakage shall be determined and the area repaired per ASME Code Section III, Subsection NB, Article NB-4450 requirements. Re-testing shall be performed until the leakage rate acceptance criterion is met.

3. QUALITY ASSURANCE

Activities in the areas of design, purchase, fabrication, assembly, inspection, testing, operation, maintenance, repair, modification of structures, systems and components, and decommissioning that are important-to-safety shall be conducted in accordance with a Commission-approved quality assurance program which satisfies the applicable requirements of 10 CFR Part 72, Subpart G, and which is established, maintained, and executed with regard to the storage system

4. HEAVY LOADS REQUIREMENTS

Each lift of an MPC or a HI-TRAC VW transfer cask must be made in accordance to the existing heavy loads requirements and procedures of the licensed facility at which the lift is made. A plant-specific review of the heavy load handling procedures (under 10 CFR 50.59 or 10 CFR 72.48, as applicable) is required to show operational compliance with existing plant specific heavy loads requirements. Lifting operations outside of structures governed by 10 CFR Part 50 must be in accordance with Section 5.2 of Appendix A.

5. APPROVED CONTENTS

Contents of the HI-STORM UMAX Canister Storage System must meet the fuel specifications given in Appendix B to this certificate.

6. DESIGN FEATURES

Features or characteristics for the site or system must be in accordance with Appendix B to this certificate.

7. CHANGES TO THE CERTIFICATE OF COMPLIANCE

The holder of this certificate who desires to make changes to the certificate, which includes Appendix A (Technical Specifications) and Appendix B (Approved Contents and Design Features), shall submit an application for amendment of the certificate.

8. PRE-OPERATIONAL TESTING AND TRAINING EXERCISE

A dry run training exercise of the loading, closure, handling, unloading, and transfer of the HI-STORM UMAX Canister Storage System shall be conducted by the licensee prior to the first use of the system to load spent fuel assemblies. The training exercise shall not be conducted with spent fuel in the MPC. The dry run may be performed in an alternate step sequence from the actual procedures, but all steps must be performed. The dry run shall include, but is not limited to the following:

a. Moving the MPC and the transfer cask into the spent fuel pool or cask loading pool.

b. Preparation of the HI-STORM UMAX Canister Storage System for fuel loading.

c. Selection and verification of specific fuel assemblies to ensure type conformance.

d. Loading specific assemblies and placing assemblies into the MPC (using a dummy fuel assembly), including appropriate independent verification.

e. Remote installation of the MPC lid and removal of the MPC and transfer cask from the spent fuel pool or cask loading pool.

f. MPC welding, NDE inspections, pressure testing, draining, moisture removal (by vacuum drying or forced helium dehydration, as applicable), and helium backfilling. (A mockup may be used for this dry-run exercise.)

g. Transfer of the MPC from the transfer cask to the VVM.

h. HI-STORM UMAX Canister Storage System unloading, including flooding MPC cavity and removing MPC lid welds. (A mockup may be used for this dry-run exercise.)

Any of the above steps can be omitted if the site has already successfully loaded a Holtec MPC System.

9. AUTHORIZATION

The HI-STORM UMAX Canister Storage System, which is authorized by this certificate, is hereby approved for general use by holders of 10 CFR Part 50 licenses for nuclear reactors at reactor sites under the general license issued pursuant to 10 CFR 72.210, subject to the conditions specified by 10 CFR 72.212, this certificate, and the attached Appendices A and B. The HI-STORM UMAX Canister Storage System may be fabricated and used in accordance with any approved amendment to CoC No. 1040 listed in 10 CFR 72.214. Each of the licensed HI-STORM UMAX Canister Storage System components (i.e., the MPC, overpack, and transfer cask), if fabricated in accordance with any of the approved CoC Amendments, may be used with one another provided an assessment is performed by the CoC holder that demonstrates design compatibility.

FOR THE U. S. NUCLEAR REGULATORY COMMISSION

DRAFT

Michele M. Sampson, Chief
Licensing Branch
Division of Spent Fuel Storage and Transportation
Office of Nuclear Material Safety
and Safeguards
Washington, DC 20555

Dated TBD

Attachments:
1. Appendix A
2. Appendix B

EXHIBIT 9

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 17, 2015

Mr. Thomas J. Palmisano
Vice President and Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3 - ISSUANCE OF AMENDMENT FOR PERMANENTLY SHUTDOWN AND DEFUELED OPERATING LICENSE AND TECHNICAL SPECIFICATIONS (TAC NOS. MF3774 AND MF3775)

Dear Mr. Palmisano:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 230 to Facility Operating License No. NPF-10, and Amendment No. 223 to Facility Operating License No. NPF-15, for the San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, respectively. The amendments consist of changes to the SONGS facility operating licenses and the Technical Specifications (TSs) in response to your application dated March 21, 2014, as supplemented by letters dated October 1, 2014; and February 23, February 25, and March 18, 2015.

The proposed amendments revise the operating licenses and associated TSs to reflect the permanent cessation of reactor operations and the permanently defueled condition of the reactor vessels at SONGS Units 2 and 3. In general, the changes eliminate those TSs applicable in operating MODES; MODES where fuel is emplaced in the reactor vessel, and certain TSs required for movement of irradiated fuel assemblies. Changes were also made to the TS definitions, administrative controls, and related to programs and procedures. The proposed amendments also revise the facility operating licenses to clarify or remove certain conditions no longer relevant and add conditions consistent with other permanently shutdown and defueled reactors. Related Amendment Nos. 227 and 220 for SONGS Units 2 and 3, respectively, were issued on September 30, 2014, to revise and remove certain requirements from Section 5.0, "Administrative Controls," of the SONGS Units 2 and 3 TSs to reflect the permanently shutdown and defueled staffing and training requirements for SONGS Units 2 and 3 operations staff.

T. Palmisano

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Thomas J. Wengert, Senior Project Manager
Plant Licensing IV-2 and Decommissioning
Transition Branch
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-361 and 50-362

Enclosures:
1. Amendment No. 230 to NPF-10
2. Amendment No. 223 to NPF-15
3. Safety Evaluation

cc w/enclosures: Distribution via Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

DOCKET NO. 50-361

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 230
License No. NPF-10

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Southern California Edison Company, et al. (SCE or the licensee), dated March 21, 2014, as supplemented by letters dated October 1, 2014; and February 23, February 25, and March 18, 2015, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 1

2. Accordingly, Facility Operating License No. NPF-10 is hereby amended to read, as follows, as indicated in the attachment to this license amendment.

Paragraph 2.B.(2) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities", to possess and use the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license;

Paragraph 2.B.(3) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

Paragraph 2.B.(4) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

Paragraph 2.C.(1) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(1) Deleted

Paragraph 2.C.(2) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 230, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Paragraph 2.C.(14) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(14) Deleted

Paragraph 2.C.(27) of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

(27) Deleted

New License Condition 2.C.(28) of Facility Operating License No. NPF-10 is hereby added to read, as follows:

(28) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 2 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 2 until such time that all spent fuel has been removed from the Unit 2 spent fuel pool.

Paragraph 2.J of Facility Operating License No. NPF-10 is hereby amended to read, as follows:

J. Deleted

New License Condition 3 of Facility Operating License No. NPF-10 is hereby added to read, as follows:

3. On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 2 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On July 22, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

   This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 2 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Meena K. Khanna, Chief
Plant Licensing IV-2 and Decommissioning
Transition Branch
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License No. NPF-10
and Technical Specifications

Date of Issuance: July 17, 2015

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

DOCKET NO. 50-362

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 223
License No. NPF-15

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Southern California Edison Company, et al. (SCE or the licensee), dated March 21, 2014, as supplemented by letters dated October 1, 2014; and February 23, February 25, and March 18, 2015, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 2

2. Accordingly, Facility Operating License No. NPF-15 is hereby amended to read, as follows, as indicated in the attachment to this license amendment.

Paragraph 2.B.(2) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities", to possess and use the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license;

Paragraph 2.B.(3) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

Paragraph 2.B.(4) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

Paragraph 2.C.(1) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(1) Deleted

Paragraph 2.C.(2) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 223, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Paragraph 2.C.(12) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(12) Deleted

Paragraph 2.C.(28) of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

(28) Deleted

New License Condition 2.C.(29) of Facility Operating License No. NPF-15 is hereby added to read, as follows:

(29) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 3 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 3 until such time that all spent fuel has been removed from the Unit 3 spent fuel pool.

Paragraph 2.J of Facility Operating License No. NPF-15 is hereby amended to read, as follows:

J. Deleted

New License Condition 3 of Facility Operating License No. NPF-15 is hereby added to read, as follows:

3. On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 3 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On June 28, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

   This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 3 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Meena K. Khanna, Chief
Plant Licensing IV-2 and Decommissioning
Transition Branch
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License No. NPF-15
and Technical Specifications

Date of Issuance: July 17, 2015

ATTACHMENT TO LICENSE AMENDMENT NO. 230

TO FACILITY OPERATING LICENSE NO. NPF-10

AND LICENSE AMENDMENT NO. 223

TO FACILITY OPERATING LICENSE NO. NPF-15

DOCKET NOS. 50-361 AND 50-362

Replace the following pages of the Facility Operating License Nos. NPF-10 and NPF-15, and Appendix A Technical Specifications, with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Facility Operating License No. NPF-10

Remove	Insert
-2-	-2-
-3-	-3-
-5-	-5-
-8-	-8-
-9-	-9-
---	-10-

Facility Operating License No. NPF-15

Remove	Insert
-2-	-2-
-3-	-3-
-4-	-4-
-5-	-5-
-7-	-7-
-9-	-9-

Technical Specifications

Remove	Insert
All pages	All pages

Facility Operating License No. NPF-10

Revised License Pages

G. The licensees have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

H. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public;

I. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Facility Operating License No. NPF-10, subject to the condition for protection of the environment set forth herein, is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied; and

J. The receipt, possession, and use of source, byproduct, and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70.

2. Based on the foregoing findings and the Partial Initial Decision issued by the Atomic Safety and Licensing Board on January 11, 1982, regarding this facility, Facility Operating License No. NPF-10 is hereby issued to the Southern California Edison Company, the San Diego Gas and Electric Company, the City of Riverside, California, and the City of Anaheim, California[1] to read as follows:

A. This license applies to the San Onofre Nuclear Generating Station, Unit 2, a pressurized water nuclear reactor and associated equipment (the facility), owned by the licensees. The facility is located in San Diego County, California, and is described in the Final Safety Analysis Report as supplemented and amended, and the Environmental Report, as supplemented and amended.

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

(1) Southern California Edison Company, San Diego Gas and Electric Company, the City of Riverside, California, and the City of Anaheim, California[1] to possess the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license;

(2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess and use the facility at the designated location in San Diego County, California in accordance with the procedures and limitations set forth in this license;

---

[1]The City of Anaheim has transferred its ownership interests in the facility, and entitlement to facility output, to Southern California Edison Company, except that it retains its ownership interests in its spent nuclear fuel and the facility's independent spent fuel storage installation located on the facility's site. In addition, the City of Anaheim retains financial responsibility for its spent fuel and for a portion of the facility's decommissioning costs. The City of Anaheim remains a licensee for purposes of its retained interests and liabilities.

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

(5) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of San Onofre Nuclear Generating Station, Units 1 and 2 and by the decommissioning of San Onofre Nuclear Generating Station Unit 1.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Deleted

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 230, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(14) Deleted

(15) Turbine Disc Inspection (Section 10.2.2, SER)

Deleted by Amendment No. 185

(16) Radioactive Waste System (Section 11.1, SER, SSER #5)

Deleted by Amendment No. 185

(17) Purge System Monitors (Section 11.3, SER, SSER #5)

Deleted by Amendment No. 185

(18) Initial Test Program (Section 14, SER)

Deleted by Amendment No. 185

(19) NUREG-0737 Conditions (Section 22)

a. Shift Technical Advisor (I.A.1.1, SSER #1)
Deleted by Amendment No. 185

b. Shift Manning (I.A.1.3. SSER #1, SSER #5)
Deleted by Amendment No. 147

c. Independent Safety Engineering Group (1.B.1.2. SSER #1)

Deleted by Amendment No. 185

d. Procedures for Transients and Accidents (I.C.1, SSER #1, SSER #2, SSER #5)

Deleted by Amendment No. 185

6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(27) Deleted

(28) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 2 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 2 until such time that all spent fuel has been removed from the Unit 2 spent fuel pool.

D. Exemptions to certain requirements of Appendices G, H and J to 10 CFR Part 50 are described in the Office of Nuclear Reactor Regulation's Safety Evaluation Report. These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions are hereby granted. The facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the regulations of the Commission.

E. SCE shall fully implement and maintain in effect all provisions of the Commission- approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contain Safeguards Information protected under 10 CFR 73.21 is entitled: "San Onofre Nuclear Generating Station Security, Training and Qualification, and Safeguards Contingency Plan, Revision 2" submitted by letter dated May 15, 2006. SCE shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The SONGS CSP was approved by License Amendment No. 225.

F. This license is subject to the following additional condition for the protection of the environment:

Before engaging in activities that may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than that evaluated in the Final Environmental Statement, SCE shall provide a written notification of such activities to the NRC Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

G. DELETED

H. SCE shall notify the Commission, as soon as possible but not later than one hour, of any accident at this facility which could result in an unplanned release of quantities of fission products in excess of allowable limits for normal operation established by the Commission.

I. SCE shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

J. Deleted

*On September 29, 1983, the Safeguards Contingency Plan was made a separate, companion document to the Physical Security Plan pursuant to the authority of 10 CFR 50.54.

3. On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 2 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On July 22, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

   This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 2 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

   A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

   B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by
Harold R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Appendix A (Technical Specifications)
2. Appendix B (Environmental Protection Plan)
3. Appendix C (Antitrust Conditions)

Date of Issuance: FEB 16 1982

Facility Operating License No. NPF-15

Revised License Pages

F. The licensees have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public;

H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Facility Operating License No. NPF-15, subject to the condition for protection of the environment set forth herein, is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied; and

I. The receipt, possession, and use of source, byproduct, and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70.

2. Based on the foregoing findings and the Partial Initial Decision issued by the Atomic Safety and Licensing Board on January 11, 1982, and the Initial Decision issued by the Atomic Safety and Licensing Board on May 14, 1982 regarding this facility, Facility Operating License No. NPF-15 is hereby issued to the Southern California Edison Company, the San Diego Gas and Electric Company, the City of Riverside, California, and the City of Anaheim, California[1] to read as follows:

A. This license applies to the San Onofre Nuclear Generating Station, Unit 3, a pressurized water nuclear reactor and associated equipment (the facility), owned by the licensees. The facility is located in San Diego County, California, and is described in the Final Safety Analysis Report, as amended, through Amendment 30, and the Environmental Report, as amended, through Amendment 6.

B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

(1) Southern California Edison Company, San Diego Gas and Electric Company, the City of Riverside, California, and the City of Anaheim, California[1] to possess the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license;

(2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess and use the facility at the designated location in San Diego County, California in accordance with the procedures and limitations set forth in this license;

[1]The City of Anaheim has transferred its ownership interests in the facility, and entitlement to facility output, to Southern California Edison Company, except that it retains its ownership interests in its spent nuclear fuel and the facility's independent spent fuel storage installation located on the facility's site. In addition, the City of Anaheim retains financial responsibility for its spent fuel and for a portion of the facility's decommissioning costs. The City of Anaheim remains a licensee for purposes of its retained interests and liabilities.

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

(5) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of San Onofre Nuclear Generating Station, Units 1 and 3 and by the decommissioning of San Onofre Nuclear Generating Station Unit 1.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Deleted

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 223, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

SCE shall comply with the antitrust conditions delineated in Appendix C to this license.

(4) Containment Tendon Surveillance (Section *3.8.1, SER, SSER #5)

Deleted by Amendment No. 26

(5) Environmental Qualification (Section 3.11, SER, SSER #3, SSER #4)

Deleted by Amendment No. 49

(6) High Burnup Fission Gas Release (Section 4.2.2.2, SER)

Deleted by Amendment No. 176

(7) Low Temperature Overpressurization Protection (Section 5.2.2.2, SER)

Deleted by Amendment No. 176

(8) Volume Control Tank Control Logic (Section 7.3.5, SSER #4)

Deleted by Amendment No. 176

(9) Compliance with Regulatory Guide 1.97 (Section 7.5.1, SER, SSER #5)

Deleted by Amendment No. 176

(10) Control System Failures (Section 7.7, SER, SSER #4)

Deleted by Amendment No. 176

(11) Diesel Generator Modifications (Section 8.3.1, SER)

Deleted by Amendment No. 176

(12) Deleted

*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(13) Turbine Disc Inspection (Section 10.2.2, SER)

Deleted by Amendment No. 176

(14) Radioactive Waste System (Section 11.1, SER, SSER #5)

Deleted by Amendment No. 176

(15) Purge System Monitors (Section 11.3, SER, SSER #5)

Deleted by Amendment No. 176

(16) Initial Test Program (Section 14, SER)

Deleted by Amendment No. 176

(17) NUREG-0737 Conditions (Section 22)

Deleted by Amendment No. 176

a. Procedures for Transients and Accidents (I.C.1, SSER #1, SSER #2, SSER #5)

Deleted by Amendment No. 176

b. Procedures for Verifying Correct Performance of Operating Activities (I.C.6, SSER #1)

Deleted by Amendment No. 176

c. Control Room Design Review (I.D.1, SSER #1)

Deleted by Amendment No. 176

d. Post Accident Sampling System (NUREG-0737 Item II.B.3)

Deleted by Amendment No. 169

e. Direct Indication of Safety Valve Position (II.D.3, SSER #1)

Deleted by Amendment No. 176

f. AFW Pump 48-hour Endurance Test (II.E.1.1, SSER #11)

Deleted by Amendment No. 176

g. Emergency Power Supply for Pressurizer Heaters (II.E.3.1, SSER #1, SSER #5)

Deleted by Amendment No. 176

h. ICC Instrumentation (II.F.2, SSER #1, SSER #2, SSER #4)

Deleted by Amendment No. 176

(27) Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(28) Deleted

(29) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 3 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 3 until such time that all spent fuel has been removed from the Unit 3 spent fuel pool.

D. Exemptions to certain requirements of Appendices G, H and J to 10 CFR Part 50 are described in the Office of Nuclear Reactor Regulation's Safety Evaluation

J. Deleted

K. Deleted by Amendment No. 176

3. On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 3 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On June 28, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 3 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by
Harold R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Attachments:
1. Attachment 1 - Deleted by Amendment No. 176
2. Appendix A (Technical Specifications)
3. Appendix B (Environmental Protection Plan)
4. Appendix C (Antitrust Conditions)

Date of Issuance: NOV 15 1982

APPENDIX A

TO THE

FACILITY OPERATING LICENSE NPF-10

AND

FACILITY OPERATING LICENSE NPF-15

TECHNICAL SPECIFICATIONS FOR

SAN ONOFRE NUCLEAR GENERATING STATION UNIT 2 AND UNIT 3

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1.0 USE AND APPLICATION

1.1 Definitions

----------NOTE----------
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
CERTIFIED FUEL HANDLER	A CERTIFIED FUEL HANDLER is an individual who complies with provisions of the CERTIFIED FUEL HANDLER training program required by TS 5.3.2.
OPERABLE–OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentions of the logical connectors.

When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

EXAMPLE

The following example illustrates the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Limiting Condition for Operation (LCOs) specify minimum requirements for ensuring safe storage of fuel assemblies. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).
DESCRIPTION	The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the facility is in a specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the facility is not within the LCO Applicability.
EXAMPLE	The following example illustrates the use of Completion Times.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Verify . . .	6 hours
	AND	
	B.2 Restore . . .	36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to perform the verification within 6 hours AND perform the restoration within 36 hours. A total of 6 hours is allowed for performing the verification and a total of 36 hours (not 42 hours) is allowed for performing the restoration from the time that Condition B was entered. If verification is performed within 3 hours, the

1.3 Completion Times

EXAMPLE (continued)	
	time allowed for performing the restoration is the next 33 hours because the total time allowed for performing the restoration is 36 hours.
IMMEDIATE COMPLETION TIME	When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE	The purpose of this section is to define the proper use and application of Frequency requirements.
DESCRIPTION	Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR. The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR, as well as certain Notes in the Surveillance column that modify performance requirements.
EXAMPLES	The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) occurs whenever any fuel assembly is stored in the fuel storage pool.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify . . .	7 days

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (7 days) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 7 days, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the facility is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the facility is in a specified condition in the Applicability of the LCO, then SR 3.0.3 becomes applicable.

1.4 Frequency

EXAMPLES (continued)

If the interval as specified by SR 3.0.2 is exceeded while the facility is not in a specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the specified condition. Failure to do so would result in a violation of SR 3.0.4.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify . . .	Prior to moving a fuel assembly . . .

Example 1.4-2 illustrates a one time performance Frequency.

This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1	LCOs shall be met during the specified conditions in the Applicability, except as provided in LCO 3.0.2.
LCO 3.0.2	Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met. If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1	SRs shall be met during the specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.
SR 3.0.2	The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.
SR 3.0.3	If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed. If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. The Completion Times of the Required Actions begin immediately upon expiration of the delay period. When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. The Completion Times of the Required Actions begin immediately upon failure to meet the Surveillance.
SR 3.0.4	Entry into a specified condition in the Applicability of an LCO shall not be made unless the LCO's Surveillances have been met within their specified Frequency. This provision shall not prevent entry into specified conditions in the Applicability that are required to comply with ACTIONS.

3.1 PLANT SYSTEMS

3.1.1 Fuel Storage Pool Water Level

LCO 3.1.1 The fuel storage pool water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of fuel assemblies in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Fuel storage pool water level not within limit.	A.1	Suspend movement of fuel assemblies in fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify the fuel storage pool water level is ≥ 23 ft above the top of irradiated fuel assemblies seated in the storage racks.	7 days

3.1 PLANT SYSTEMS

3.1.2 Fuel Storage Pool Boron Concentration

LCO 3.1.2 The fuel storage pool boron concentration shall be ≥ 2000 ppm.

APPLICABILITY: Whenever any fuel assembly is stored in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Fuel storage pool boron concentration not within limit.	A.1	Suspend movement of fuel assemblies in the fuel storage pool.	Immediately
	AND		
	A.2	Initiate action to restore fuel storage pool boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	Verify the fuel storage pool boron concentration is within limit.	7 days

3.1 PLANT SYSTEMS

3.1.3 Spent Fuel Assembly Storage

LCO 3.1.3 The combination of initial enrichment and burnup of each SONGS 2 and 3 spent fuel assembly stored in Region I shall be within the acceptable burnup domain of Figure 3.1.3-1 or Figure 3.1.3-2 or the fuel assembly shall be stored in accordance with Technical Specification 4.3.1.1.

The combination of initial enrichment and burnup of each SONGS 2 and 3 spent fuel assembly stored in Region II shall be within the acceptable burnup domain of Figure 3.1.3-3 or Figure 3.1.3-4, or the fuel assembly shall be stored in accordance with Technical Specification 4.3.1.1.

Each SONGS 1 uranium dioxide spent fuel assembly stored in Region II shall be stored in accordance with Technical Specification 4.3.1.1.

APPLICABILITY: Whenever any fuel assembly is stored in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Requirements of the LCO not met.	A.1	Initiate action to bring the noncomplying fuel assembly into compliance.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify by administrative means the initial enrichment, burnup, and cooling time of the fuel assembly are in accordance with LCO 3.1.3, or Design Features 4.3.1.1, or Licensee Controlled Specification (LCS) 4.0.100. Rev 2, dated 09/27/07.	Prior to moving a fuel assembly to any spent fuel pool storage location.

FIGURE 3.1.3-1

MINIMUM BURNUP AND COOLING TIME VS. INITIAL ENRICHMENT
FOR
UNRESTRICTED PLACEMENT OF SONGS 2 AND 3 FUEL
IN
REGION I RACKS

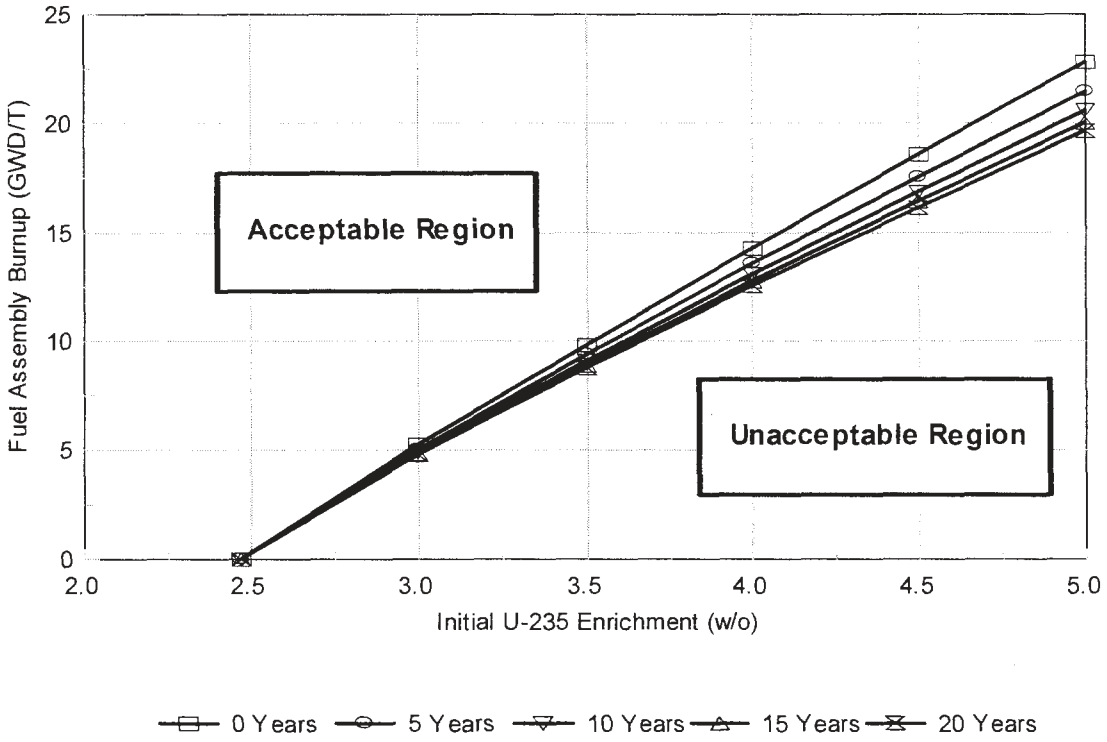


FIGURE 3.1.3-2

MINIMUM BURNUP AND COOLING TIME VS. INITIAL ENRICHMENT
FOR
PLACEMENT OF SONGS 2 AND 3 FUEL IN PERIPHERAL POOL LOCATIONS
IN
REGION I RACKS

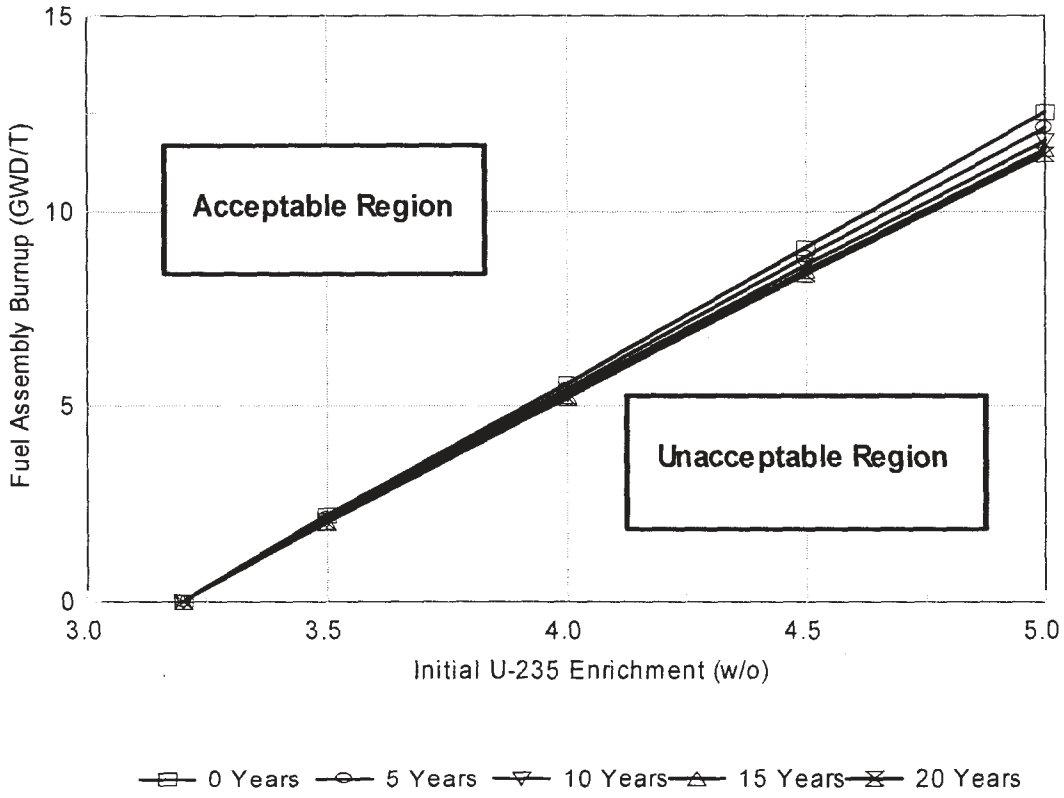


FIGURE 3.1.3-3

MINIMUM BURNUP AND COOLING TIME VS. INITIAL ENRICHMENT
FOR
UNRESTRICTED PLACEMENT OF SONGS 2 AND 3 FUEL
IN
REGION II RACKS

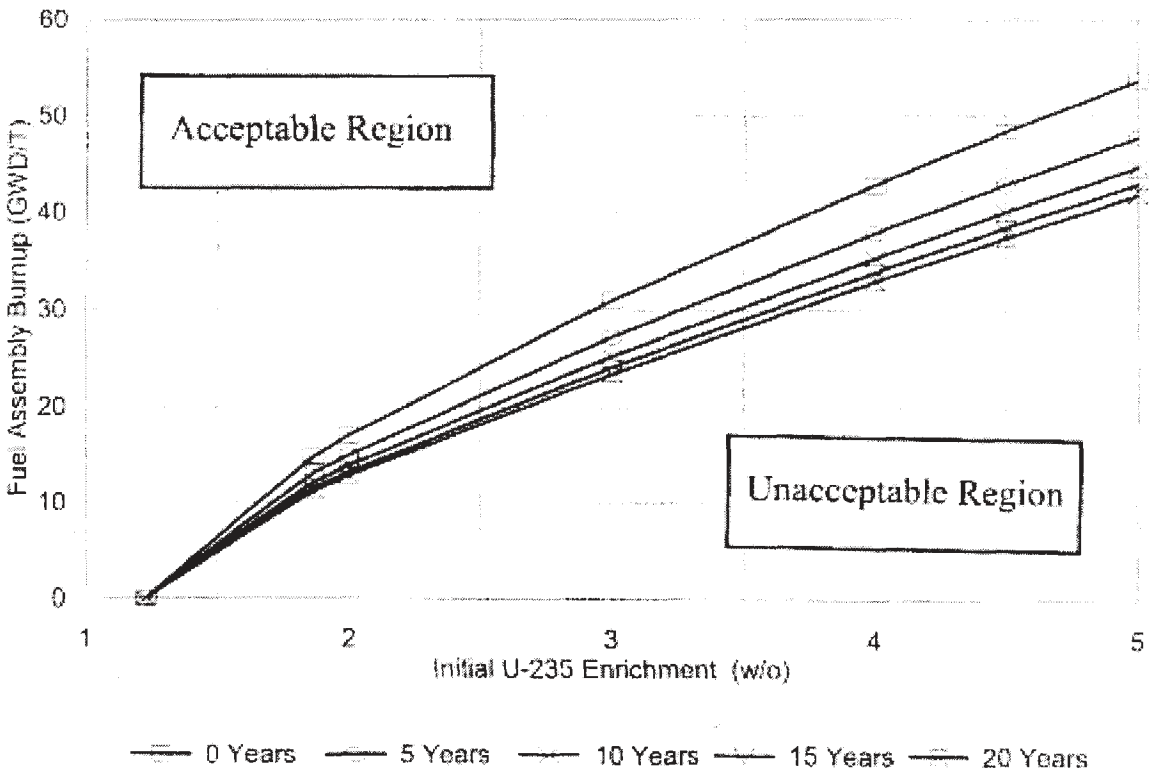
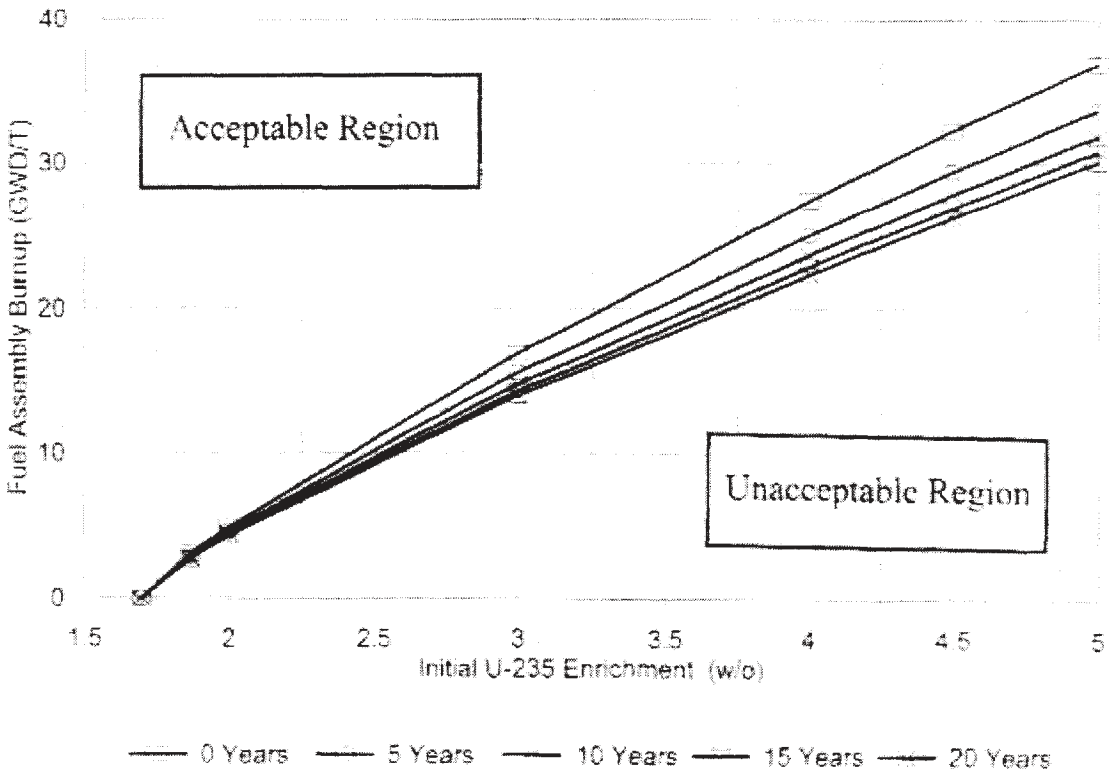


FIGURE 3.1.3-4

MINIMUM BURNUP AND COOLING TIME VS. INITIAL ENRICHMENT
FOR
PLACEMENT OF SONGS 2 AND 3 FUEL IN PERIPHERAL POOL LOCATIONS
IN
REGION II RACKS



4.0 DESIGN FEATURES

4.1 Site

4.1.1 Exclusion Area Boundary

The exclusion area boundary shall be as shown in Figure 4.1-1.

4.1.2 Low Population Zone (LPZ)

The LPZ shall be as shown in Figure 4.1-2.

4.2 Deleted.

4.0 DESIGN FEATURES (continued)

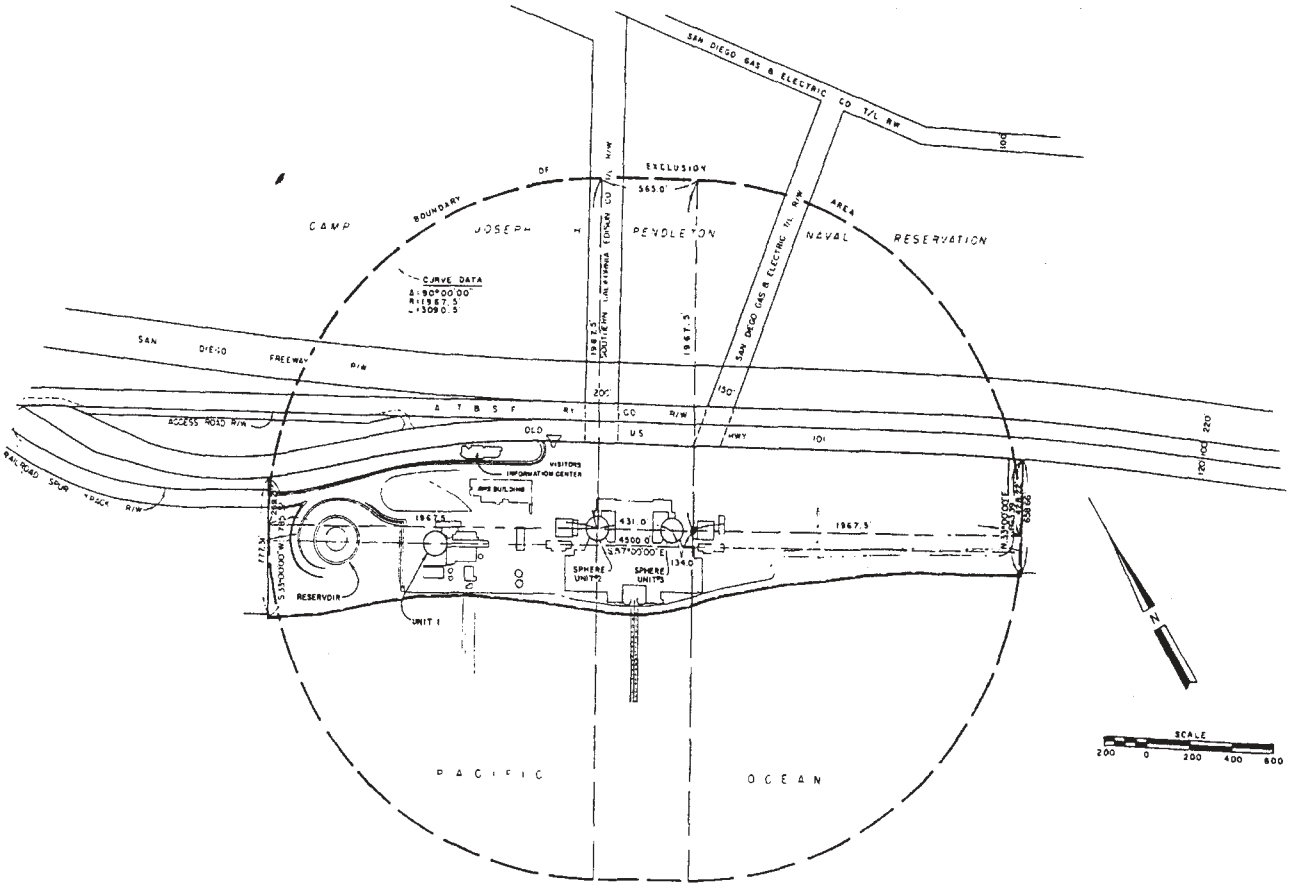


Figure 4.1-1 (page 1 of 1)
Exclusion Area Boundary

4.0 DESIGN FEATURES (continued)

Figure 4.1-2 (page 1 of 1)
Low Population Zone

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 4.8 weight percent;

b. $K_{eff} < 1.0$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. $K_{eff} \leq 0.95$ if fully flooded with water borated to 1700 ppm, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

d. Three or five Borated stainless steel guide tube inserts (GT-Insert) may be used. When three borated stainless steel guide tube inserts are used, they will be installed in an assembly's center guide tube, the guide tube associated with the serial number, and the diagonally opposite guide tube. Fuel containing GT-Inserts may be placed in either Region I or Region II. However, credit for GT-Inserts is only taken for Region II storage.

A five-finger CEA may be installed in an assembly. Fuel containing a five-finger CEA may be placed in either Region I or Region II. Credit for inserted 5-finger CEAs is taken for both Region I and Region II.

e. A nominal 8.85 inch center to center distance between fuel assemblies placed in Region II;

f. A nominal 10.40 inch center to center distance between fuel assemblies placed in Region I;

g. Prior to using the storage criteria of LCO 3.1.3 and LCS 4.0.100, the following uncertainties will be applied:

(1) The calculated discharge burnup of San Onofre Units 2 and 3 assemblies will be reduced by 6.6%.

(2) The calculated discharge burnup of San Onofre Unit 1 fuel assemblies will be reduced by 10.0%.

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

h. Units 2 and 3 fuel assemblies with a burnup in the "acceptable range" of Figure 3.1.3-1 are allowed unrestricted storage in Region I;

i. Units 2 and 3 fuel assemblies with a burnup in the "acceptable range" of Figure 3.1.3-2 are allowed unrestricted storage in the peripheral pool locations with 1 or 2 faces toward the spent fuel pool walls of Region I;

j. Units 2 and 3 fuel assemblies with a burnup in the "acceptable range" of Figure 3.1.3-3 are allowed unrestricted storage in Region II;

k. Units 2 and 3 fuel assemblies with a burnup in the "acceptable range" of Figure 3.1.3-4 are allowed unrestricted storage in the peripheral pool locations with 1 or 2 faces toward the spent fuel pool walls of Region II;

l. Units 2 and 3 fuel assemblies with a burnup in the "unacceptable range" of Figure 3.1.3-1, Figure 3.1.3-2, Figure 3.1.3-3, and Figure 3.1.3-4 will be stored in compliance with Licensee Controlled Specification 4.0.100 Rev. 2, dated 9/27/07; and

m. Each SONGS 1 uranium dioxide spent fuel assembly stored in Region II shall be stored in accordance with Licensee Controlled Specification 4.0.100 Rev. 2, dated 9/27/07.

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below Technical Specification 3.1.1 value (23 feet above the top of irradiated fuel assemblies seated in the storage racks).

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1542 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1	The corporate officer with direct responsibility for the plant shall be responsible for overall management of the San Onofre Nuclear Generating Station, and all site support functions. He shall delegate in writing the succession to this responsibility during his absence.
5.1.2	The Shift Manager shall be responsible for the ultimate command decision authority for all unit activities which affect the safety of the plant, site personnel, and/or the general public.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for plant operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear fuel.

a. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These relationships, including the plant-specific titles of those personnel fulfilling the responsibilities for the positions delineated in these Technical Specifications, are documented in the UFSAR.

b. The corporate officer with direct responsibility for the plant shall be responsible for overall safe handling and storage of nuclear fuel and shall have control over those onsite activities necessary for safe handling and storage of the nuclear fuel.

c. A specified corporate officer (or officers) shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure safe management of nuclear fuel.

d. The individuals who train CERTIFIED FUEL HANDLERS, and those who carry out radiation protection and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their ability to perform their assigned functions.

5.2.2 FACILITY STAFF

The facility staff organization shall include the following:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 5.2.2-1.

b. At least one person qualified as Emergency Coordinator/Emergency Director shall be in the Control Room when nuclear fuel is stored in the spent fuel pools.

5.2 Organization

5.2.2 FACILITY STAFF (continued)

c. Shift crew composition may be less than the minimum requirement of Table 5.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements. During such absences, no fuel movement or movement of heavy loads over storage racks containing fuel is permitted.

d. Oversight of fuel handling operations shall be provided by a CERTIFIED FUEL HANDLER.

e. The Shift Manager shall be a CERTIFIED FUEL HANDLER.

f. An individual qualified in radiation protection procedures shall be on site during fuel handling operations or movement of loads over the storage racks containing fuel.

5.2 Organization (continued)

Table 5.2.2-1
Minimum Shift Crew Composition

POSITION	MINIMUM STAFFING
CERTIFIED FUEL HANDLER	1*
Certified Operator	1

Note: The Certified Operator position may be filled by a CERTIFIED FUEL HANDLER.
* May be shared between Units 2 and 3.

5.0 ADMINISTRATIVE CONTROLS

5.3 Facility Staff Qualifications

5.3.1	Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except: a) the radiation protection manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.
5.3.2	An NRC approved training and retraining program for the CERTIFIED FUEL HANDLERS shall be maintained.

5.0 ADMINISTRATIVE CONTROLS

5.4 Technical Specifications (TS) Bases Control

5.4.1 Changes to the Bases of the TS shall be made under appropriate administrative controls.

5.4.2 Changes to the Bases may be made without prior NRC approval provided the changes do not require either of the following:

a. A change in the TS incorporated in the license; or

b. A change to the updated UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

5.4.3 The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

5.4.4 Proposed changes that meet the criteria of (a) or (b) above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC every 24 months.

5.0 ADMINISTRATIVE CONTROLS

5.5 Procedures, Programs, and Manuals

5.5.1 Procedures

5.5.1.1 Scope

Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory guide 1.33, Revision 2, Appendix A, February 1978;

b. Deleted.

c. Quality assurance for effluent and environmental monitoring using the guidance in Regulatory Guide 4.15, Revision 1, 1979;

d. Fire Protection Program implementation; and

e. Programs, as specified in Specification 5.5.2.

5.5.2 Programs and Manuals

The following programs and manuals shall be established, implemented, and maintained.

5.5.2.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the Radiological Environmental Monitoring Program;

b. The ODCM shall also contain the Radioactive Effluent Controls required by Specification 5.5.2.3 and Radiological Environmental Monitoring programs required by the LCS, and descriptions of the information that should be included in the Annual Radiological Environmental Operating Report and the Radioactive Effluent Release Report required by Specification 5.7.1.2 and Specification 5.7.1.3.

5.5.2.1.1 Licensee-initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

5.5 Procedures, Programs, and Manuals

5.5.2.1.1 Licensee-initiated changes to the ODCM (continued):

1. Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s);

2. A determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.106, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

3. Documentation of the fact that the change has been reviewed and found acceptable.

b. Shall become effective upon review and approval by the corporate officer with direct responsibility for the plant or designee.

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5.2.2 Deleted

5.5.2.3 Radioactive Effluent Controls Program

This program conforming to 10 CFR 50.36a provides for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by operating procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 CFR 20, Appendix B, Table II, Column 2;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.106 and with the methodology and parameters in the ODCM;

5.5 Procedures, Programs, and Manuals

5.5.2.3 Radioactive Effluent Controls Program (continued)

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2 percent of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary conforming to the dose associated with 10 CFR 20, Appendix B, Table II, Column 1;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives greater than 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.2.4 Deleted

5.5.2.5 Deleted

5.5.2.6 Deleted

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.7 Storage Tank Radioactivity Monitoring Program

This program provides controls for the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures".

The program shall include a surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Waste Management System is less than the amount that would result in concentrations less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.0 ADMINISTRATIVE CONTROLS

5.6 Deleted

5.0 ADMINISTRATIVE CONTROLS

5.7 Reporting Requirements

5.7.1 Routine Reports

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted in accordance with 10 CFR 50.4. The reports shall be addressed to the U.S. Nuclear Regulatory Commission, Attention: Document Control Desk, Washington, D.C., with a copy to the Regional Administrator of the Regional Office of the NRC, unless otherwise noted.

5.7.1.1 Deleted

5.7.1.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the facility during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. The report shall identify the thermoluminescent dosimeter (TLD) results that represent collocated dosimeters in relation to the NRC TLD program and the exposure period associated with each result. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.7 Reporting Requirements (continued)

5.7.1.3 Radiological Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the facility during the previous calendar year shall be submitted before May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents released from the facility. The report shall also include a summary of the quantities of solid radioactive waste shipped from the facility directly to the disposal site and quantities of solid radioactive waste shipped from the facility's intermediary processor to the disposal site. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program (PCP) and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.0 ADMINISTRATIVE CONTROLS

5.8 High Radiation Area

5.8.1 Each high radiation area as defined 10 CFR 20 shall be barricaded and conspicuously posted as a high radiation area, and entrance thereto shall be controlled by requiring issuance of a Radiation Exposure Permit (REP).

Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

a. A radiation monitoring device that continuously indicates the radiation dose rate in the area,

b. A radiation monitoring device that continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rates in the area have been determined and personnel have been made knowledgeable of them,

c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device. This individual is responsible for providing positive radiation protection control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified in the radiation protection procedures or the applicable REP.

5.8.2 In addition, areas that are accessible to personnel and that have radiation levels greater than 1.0 rem (but less than 500 rads at 1 meter) in 1 hour at 30 cm from the radiation source, or from any surface penetrated by the radiation, shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the shift manager on duty or radiation protection supervisor. Doors shall remain locked except during periods of access by personnel under an approved REP that specifies the dose rates in the immediate work areas and the maximum allowable stay time for individuals in that area. In lieu of a stay time specification on the REP, direct or remote continuous surveillance (such as closed circuit TV cameras) may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities being performed within the area.

5.8.3 Individual high radiation areas that are accessible to personnel, that could result in radiation doses greater than 1.0 rem in 1 hour, and that are within large areas where no enclosure exists to enable locking and where no enclosure can be reasonably constructed around the individual area shall be barricaded and conspicuously posted. A flashing light shall be activated as a warning device whenever the dose rate in such an area exceeds or is expected to exceed 1.0 rem in 1 hour at 30 cm from the radiation source or from any surface penetrated by the radiation.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 230 TO FACILITY OPERATING LICENSE NO. NPF-10

AND AMENDMENT NO. 223 TO FACILITY OPERATING LICENSE NO. NPF-15

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3

DOCKET NOS. 50-361 AND 50-362

1.0 INTRODUCTION

By letter dated June 12, 2013 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML131640201), Southern California Edison (SCE, the licensee) submitted a certification to the U.S. Nuclear Regulatory Commission (NRC) indicating its intention to permanently cease power operations at San Onofre Nuclear Generating Station (SONGS), Units 2 and 3 as of June 7, 2013, pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) paragraph 50.82(a)(1)(i). By letters dated June 28, 2013 (ADAMS Accession No. ML13183A391), and July 22, 2013 (ADAMS Accession No. ML13204A304), SCE submitted certifications of permanent removal of fuel from the Unit 3 and Unit 2 reactor vessels as of October 5, 2012, and July 18, 2013, respectively, pursuant to 10 CFR 50.82(a)(1)(ii). Upon docketing of these certifications, and pursuant to 10 CFR 50.82(a)(2), the SONGS Units 2 and 3 facility operating licenses no longer authorize operation of the reactors or emplacement or retention of fuel into the reactor vessels. Spent fuel is currently stored onsite in the spent fuel pools (SFPs) and in the onsite independent spent fuel storage installation (ISFSI).

By letter dated March 21, 2014 (ADAMS Accession No. ML14085A141), as supplemented by letters dated October 1, 2014; and February 23, February 25, and March 18, 2015 (ADAMS Accession Nos. ML14280A264, ML15058A030, ML15058A033, and ML15082A017, respectively), SCE submitted a license amendment request consisting of amendment applications to Facility Operating License Nos. NPF-10 and NPF-15 for SONGS Units 2 and 3, respectively. The proposed amendments would revise the facility operating licenses and revise the associated technical specifications (TSs) to reflect the permanent cessation of operations of SONGS Units 2 and 3.

The supplemental letters dated October 1, 2014; and February 23, February 25, and March 18, 2015, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no

significant hazards consideration determination as published in the *Federal Register* on September 16, 2014 (79 FR 55513).

As stated above, pursuant to 10 CFR 50.82(a)(2), the 10 CFR Part 50 licenses for SONGS Units 2 and 3 no longer authorize operation of the reactors or emplacement or retention of fuel in the reactor vessels. SONGS Units 2 and 3 have been shut down since January 2012. At the time of the licensee's submittal, the fission product inventory of all spent fuel that is stored in the SONGS Units 2 and 3 spent fuel pools had decayed more than two years since last irradiated in the reactor core. SONGS Unit 1 was permanently shut down in 1993 and is already in the decommissioning phase where above ground structures have been dismantled and the spent fuel is stored in either the SONGS ISFSI or in the GE-Hitachi Morris facility.

The existing SONGS TSs contain limiting conditions for operation (LCOs) that provide for appropriate functional capability of equipment required for safe operation of the facility, including the plant being in a defueled condition. Since the safety function related to safe storage and management of irradiated fuel at an operating plant is similar to the corresponding function at a permanently defueled facility, the existing TSs provide an appropriate level of control. However, the majority of the existing TSs are only applicable when the reactor is in an operational MODE. Since the SONGS Units 2 and 3, Part 50 licenses no longer authorize emplacement or retention of fuel in the reactor vessels, the LCOs (and associated surveillance requirements (SRs)) that do not apply in a defueled condition are being proposed for deletion. The proposed amendments revise the operating licenses and associated TSs to reflect the permanent cessation of reactor operations and the permanently defueled condition of the reactor vessels at SONGS Units 2 and 3. In general, the changes eliminate those TSs applicable in operating MODES; MODES where fuel is emplaced in the reactor vessel, and certain TSs required for movement of irradiated fuel assemblies. Changes were also proposed to TS definitions, administrative controls, and related to programs and procedures. The proposed amendments also revise the facility operating licenses to clarify or remove certain conditions no longer relevant and add conditions consistent with other permanently shutdown and defueled reactors.

Amendment Nos. 227 and 220 for SONGS Units 2 and 3, respectively, were issued by the NRC on September 30, 2014 (ADAMS Accession No. ML14183B240), to revise certain requirements in the permanently shutdown and defueled facility's TSs, Section 5.0, "Administrative Controls," related to responsibilities, organization, and facility staff qualifications that reflect new staffing and training requirements for operating staff. Issuance of the enclosed amendments, in conjunction with the previously issued TS administrative control amendments, completes the revision to the SONGS permanently shutdown and defueled technical specifications. The TSs being proposed for revision by SCE for incorporation into the SONGS Units 2 and 3 facility operating licenses, referred to by SCE as the Permanently Defueled Technical Specifications (PDTS), have been combined into a single TS that applies to both units. The licensee states that the changes to the facility operating licenses and TSs provide an appropriate level of safety, considering the reduced risk of an offsite radiological release from the remaining postulated design-basis accidents (DBAs) associated with a defueled plant, as described in this safety analysis.

2.0 REGULATORY EVALUATION

2.1 Technical Specifications

Section 182a of the Atomic Energy Act requires applicants for nuclear power plant operating licenses to include TSs as part of the application. The NRC's regulatory requirements related to the content of the TSs are contained in 10 CFR 50.36, "Technical specifications." Pursuant to 10 CFR 50.36, each operating license issued by the Commission includes TSs and includes items in the following categories: (1) safety limits, limiting safety systems settings and control settings, (2) LCOs, (3) SRs, (4) design features, (5) administrative controls, (6) decommissioning, (7) initial notification, and (8) written reports.

Section 50.36 of 10 CFR states, in part, that "safety limits for nuclear reactors are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity... Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions."

Section 50.36 of 10 CFR provides four criteria to define the scope of equipment and parameters to be included in the TS LCOs. These criteria were developed for licenses authorizing operation (i.e., operating reactors) and focused on instrumentation to detect degradation of the reactor coolant system (RCS) pressure boundary, process variables and equipment, design features, or operating restrictions that affect the integrity of fission product barriers during DBAs or transients. A fourth criterion refers to the use of operating experience and probabilistic risk assessment to identify and include in the TSs those structures, systems, and components (SSCs) shown to be significant to public health and safety.

SRs are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the LCO will be met.

Design features to be included are those features of the facility such as materials of construction and geometric arrangements, which, if altered or modified, would have a significant effect on safety and are not covered in categories described in paragraphs 50.36(c)(1), (2), and (3).

Administrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility is in a safe manner.

The regulations in 10 CFR 50.36 further state that TSs involving safety limits, limiting safety system settings, and limiting control system settings; LCOs; SRs; design features; and administrative controls for decommissioning facilities will be developed on a case-by-case basis.

A general discussion of the criteria that were used by the NRC staff in its evaluation to ensure that the TS LCOs proposed for deletion are no longer required to be included in the TSs is

provided below. These criteria were also used in the evaluation of the proposed changes to the existing TSs and the proposed new TSs.

Criterion 1 of 10 CFR 50.36(c)(2)(ii)(A) states that TS LCOs must be established for "installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary [RCPB]." Since no fuel is present in the reactor, maintenance of the RCS pressure boundary as a fission product barrier is no longer relevant at the SONGS Units 2 and 3 facility, and therefore, this criterion is not applicable.

Criterion 2 of 10 CFR 50.36(c)(2)(ii)(B) states that TS LCOs must be established for a "process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier." The purpose of this criterion is to capture those process variables that have initial values assumed in the DBA and transient analyses, and which are monitored and controlled during power operation. The scope of DBAs applicable to a reactor permanently shutdown and defueled is reduced from those postulated for an operating reactor, and most TSs satisfying Criterion 2 are no longer applicable. The scope of applicable DBAs that apply to SONGS Units 2 and 3 are discussed in more detail in Sections 3.1 through 3.6 of this safety evaluation (SE). There are no transients that continue to apply to the permanently shutdown and defueled reactors.

Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) states that TS LCOs must be established for a SSC "that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier." The intent of this criterion is to capture into TSs those SSCs that are part of the primary success path of a safety sequence analysis. Also captured by this criterion are those support and actuation systems that are necessary for items in the primary success path to successfully function. The primary success path of a safety sequence analysis consists of the combination and sequences of equipment needed to operate (including consideration of the single failure criterion), so that the plant response to DBAs and transients limits the consequences of these events to within the appropriate acceptance criteria. The scope of applicable DBAs that apply to SONGS Units 2 and 3 are discussed in more detail in Sections 3.1 through 3.6 of this SE. There are no transients that continue to apply to the permanently shutdown and defueled reactors.

Criterion 4 of 10 CFR 50.36(c)(2)(ii)(D) states that TS LCOs must be established for SSCs "which operating experience or probabilistic risk assessment has shown to be significant to public health and safety." The intent of this criterion is that risk insights and operating experience be factored into the establishment of TS LCOs. There are no longer any DBAs at SONGS Units 2 and 3 that can result in a significant offsite radiological risk to public health and safety.

The NRC staff notes that in the course of this evaluation, information contained in DRAFT NUREG-1625, "Proposed Standard Technical Specifications for Permanently Defueled Westinghouse Plants," March 1998 (ADAMS Accession No. ML082330233), was also considered. This draft NUREG provides examples of decommissioning TSs for Westinghouse

pressurized water reactors that the staff has previously found acceptable during TS reviews for permanently shutdown and defueled reactors.

2.2 Radiological Consequences from Design-Basis Accidents

During normal power reactor operations, the forced flow of water through the RCS removes the heat generated by the reactor. The RCS, operating at high temperatures and pressures, transfers this heat through the steam generator (SG) tubes to the secondary system. The most severe postulated accidents for nuclear power plants involve damage to the nuclear reactor core and the release of large quantities of fission products to the RCS and subsequent release of some fission products to the environment. Many of the accident scenarios postulated in the facility safety analysis report involve failures or malfunctions of systems that could affect the reactor core. With the termination of reactor operations and the permanent removal of the fuel from the reactor core, such accidents are no longer possible. Therefore, the postulated accidents involving failure or malfunction of the reactor, RCS, or secondary system are no longer applicable. Postulated accidents that could potentially apply to a permanently shutdown and defueled facility include a fuel handling accident (FHA), an accidental release of waste liquid, an accidental release of waste gas, a spent fuel cask drop accident, and a spent fuel pool boiling event. The potential offsite consequences of these events are affected by the time available for decay of fission products in the fuel and, possibly, the availability of engineered safety features, such as ventilation systems to filter fission products from the accident area atmosphere before they are released outside the facility.

The regulations in 10 CFR 50.67, "Accident source term" state, in part, that:

> (i) An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release, would not receive a radiation dose in excess of 0.25 Sv [Sievert] (25 rem) total effective dose equivalent (TEDE), (ii) An individual located at any point on the outer boundary of the low population zone, who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage), would not receive a radiation dose in excess of 0.25 Sv (25 rem) total effective dose equivalent (TEDE), and (iii) Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident.

Appendix A to 10 CFR Part 50, "General Design Criteria (GDC)," Criterion 19--Control room, states, in part:

> A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving

> radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident. Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Regulatory Guide (RG) 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," Revision 0, July 2000 (ADAMS Accession No. ML003716792), provides the methodology for analyzing the radiological consequences of several DBAs to show compliance with 10 CFR 50.67 - Accident source term. Regulatory Guide 1.183 provides guidance to licensees on acceptable application of alternate source term (AST) submittals, including acceptable radiological analysis assumptions for use in conjunction with the AST.

NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reactor] Edition," SRP, Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," Revision 0, July 2000 (ADAMS Accession No. ML003734190), provides review guidance to the NRC staff for the review of alternative source term amendment requests. SRP Section 15.0.1 states that the NRC reviewer should evaluate the proposed change against the guidance in RG 1.183. As provided in RG 1.183, the dose acceptance criteria for an FHA are a TEDE of 6.3 rem at the exclusion area boundary (EAB) for the worst 2 hours, 6.3 rem at the outer boundary of the low population zone (LPZ), and 5 rem in the control room (CR) for the duration of the accident.

SRP 11.0, Branch Technical Position 11-5, "Postulated Radioactive Release Due to a Waste Gas System Leak or Failure," provides guidance to the NRC staff in assessing the analysis of an accidental release from the waste gas system.

The NRC approved implementation of the AST methodology at SONGS Units 2 and 3, by Amendment Nos. 210 and 202, "San Onofre Nuclear Generating Station, Units 2 and 3 – Issuances of Amendments Re: Full-Scope Implementation of an Alternative Source Term (TAC Nos. MC5495 and MC5496)," dated December 29, 2006 (ADAMS Accession No. ML063400359). These license amendments represent full scope implementation of the AST, as described in RG 1.183.

NRC Regulatory Issue Summary (RIS) 2006-04, "Experience with Implementation of Alternative Source Terms," dated March 7, 2006 (ADAMS Accession No. ML053460347), discusses experiences with analyzing an accident involving a release from off-gas or waste systems. As part of full AST implementation, some licensees have included an accident involving a release from their off-gas or waste system. For this type of accident, licensees have proposed acceptance criteria of 500 millirem (mrem) TEDE. The acceptance criterion for this event is that associated with the dose to an individual member of the public, as described in 10 CFR Part 20, "Standards for Protection Against Radiation." When the NRC revised 10 CFR Part 20 to incorporate a TEDE dose, the offsite dose to an individual member of the public was changed

from 500 mrem whole body to 100 mrem TEDE. Therefore, a licensee who chooses to implement AST for an off-gas or waste gas system release, as did SCE, should base its acceptance criteria on 100 mrem TEDE. Licensees may also choose not to implement AST for this accident and continue with their existing analysis and acceptance criteria of 500 mrem whole body.

The U.S. Environmental Protection Agency's (EPA's) "Protective Action Guide (PAG) and Planning Guidance for Radiological Incidents," Draft for Interim Use and Public Comment, issued March 2013 (PAG Manual), provides radiological protection criteria for application to all incidents that would require consideration of protective actions, with the exception of nuclear war. This manual provides recommended numerical PAGs for the principal protective actions available to public officials during a radiological incident.

The Nuclear Energy Institute (NEI) document NEI 99-01, "Development of Emergency Action Levels for Non-Passive Reactors," Revision 6, dated November 2012 (ADAMS Accession No. ML12326A805), provides guidance for the development of emergency action levels (EALs) for reactors in a permanently defueled condition. NEI 99-01, Revision 6, was endorsed by the NRC in a letter dated March 28, 2013 (ADAMS Accession No. ML12346A463). NEI 99-01 states that the accident analysis necessary to adopt the permanently defueled EAL scheme must confirm that the source terms and release motive forces are not sufficient to warrant classification of a site area emergency (SAE) or General Emergency, resulting in the maximum classification level of an Alert during an accident. An SAE would be declared for any event where exposure levels beyond the EAB are expected to exceed 10 percent of the EPA PAGs, which are a projected dose of 1 to 5 rem TEDE in four days for sheltering or evacuation of the public, and a projected dose of 5 rem child thyroid dose from radioactive iodine for administration of prophylactic drugs (potassium iodide). Correspondingly, NEI 99-01 established the SAE classification threshold as 100 mrem TEDE or 500 mrem thyroid committed dose equivalent.

3.0 TECHNICAL EVALUATION

3.1 Design-Basis Accident Analysis

SCE described that, with the permanent cessation of reactor operations and permanent removal of fuel from the reactor vessels for SONGS Units 2 and 3, most of the initial conditions, and most of the accident and transient analyses, that were included in Chapter 15 of the SONGS Updated Final Safety Analysis Report (UFSAR) when Units 2 and 3 were authorized to operate, are no longer possible. Therefore, SCE has updated the SONGS UFSAR to reflect that accidents and transients involving the failure or malfunction of fuel within primary containment, the RCS, or the secondary system are no longer applicable. The only DBA scenarios with the potential to result in a radiological release, as described in the UFSAR that are applicable to the permanently shutdown and defueled SONGS Units 2 and 3, are an FHA in the fuel handling building (FHB), a spent fuel cask drop accident, a SFP boiling accident, a liquid radioactive waste system leak or failure, a radioactive release due to liquid tank failures, and an accidental release of waste gas. Because the waste gas decay tanks have been purged of their contents and analyses of liquid tank failures in SONGS UFSAR Section 15.7.3.3.5 describe that no credible liquid release would exceed 10 CFR Part 20 limits, an accidental release of waste gas

and a liquid tank failure are not relevant at SONGS. The licensee determined that the remaining DBAs would be within relevant regulatory limits, assuming the fuel activity calculated as of August 2013 and without credit for dose consequence mitigation by engineered safety feature (ESF) systems. The NRC staff's technical evaluation of the licensee's analysis of the remaining DBAs at SONGS is provided in Sections 3.2 through 3.6, below.

3.2 Fuel Handling Accident Inside Fuel Building

A revision to the FHA accident analysis was incorporated into the SONGS UFSAR, Section 15.7.3.4, under the provisions of 10 CFR 50.59, "Changes, tests, and experiments," to address the permanently defueled condition. The analysis determined a reasonable time, post-cessation of operations, for movement of fuel from the SFP during which, if an FHA occurs, dose consequences would be within 10 CFR 50.67 and RG 1.183 dose limits. The licensee evaluated the maximum 2-hour TEDE to an individual located at the EAB, and the 30-day TEDE to an individual at the outer boundary of the LPZ and in the CR. The resulting doses in SCE's analyses are less than the RG 1.183 and SRP 15.0.1 dose acceptance criteria, the 10 CFR 50.67 limits, and the EPA PAG levels recommended for protection of the public.

The FHA inside the FHB (FHA-FHB) involves the inadvertent dropping of a fuel assembly during fuel handling operations, and the subsequent rupture of fuel pins in the dropped assembly and any stationary assembly impacted by the dropped assembly. A maximum of 472 fuel rods are assumed to fail, as a result of the drop of a fuel assembly onto the fuel assemblies stored in SFP fuel racks. The fission product inventory in the fuel rod gap of the damaged rods is assumed to be released instantaneously into the SFP. The FHA-FHB dose analysis models 17 months (12,240 hours) of radioactive decay prior to the event. The NRC staff finds that the decay time assumed by the licensee is consistent with RG 1.183, Regulatory Position 3.1, "Fission Product Inventory," which provides that, "For events postulated to occur while the facility is shutdown, e.g., a fuel handling accident, radioactive decay from the time of shutdown may be modeled."

The SFP water level is controlled by current SONGS Units 2 and 3 TS LCO 3.7.16 (renumbered to TS 3.1.1 in the proposed permanently defueled TSs), which limits the movement of irradiated fuel assemblies in the SFP, unless the water level is at least 23 feet over the top of the irradiated fuel assemblies, seated in the storage racks. As such, the licensee assumes that the SFP water level is at least 23 feet over the top of the irradiated fuel assemblies, seated in the storage racks, at the commencement of an FHA-FHB.

Should an FHA occur, fission products released from the damaged fuel are decontaminated by passage through the pool water, with the degree of decontamination dependent upon their physical and chemical forms. The licensee assumed no decontamination for noble gases, a decontamination factor of 200 for radioiodine, and retention of all aerosol and particulate fission products. This is consistent with RG 1.183, Appendix B, Section 2, "Water Depth," which provides that, "If the depth of water above the damaged fuel is 23 feet or greater, the decontamination factors for the elemental and organic species are 500 and 1, respectively, giving an overall effective decontamination factor of 200..."

The radioactive material that escapes from the SFP to the FHB is assumed to be released to the environment over a 2-hour time period. The FHA-FHB dose analysis does not credit the generation of an engineered safety feature actuation system (ESFAS) fuel handling building isolation signal (FHIS). The FHB normal ventilation exhaust is assumed to remain operational throughout the FHA-FHB event. The FHA-FHB AST dose analysis does not model a reduction in the amount of radioactive material available for release from the FHB by the fuel handling building Post-Accident Cleanup Unit (PACU) filter system. Therefore, the licensee assumes the release to the environment is an unfiltered release via the FHB normal ventilation exhaust system through the main plant vent, or as leakage through FHB penetrations. This is consistent with RG 1.183, Appendix B, Section 4.1, which states, "The radioactive material that escapes from the fuel pool to the fuel building is assumed to be released to the environment over a 2-hour time period."

Activity released during the FHA-FHB event is transported by atmospheric dispersion to the CR heating, ventilation and air conditioning (HVAC) intake and to the offsite EAB and LPZ dose receptors. Consistent with RG 1.183, Regulatory Position 5.3, "Meteorology Assumptions," the atmospheric dispersion factor values for the EAB and the LPZ, which were approved by the NRC during initial facility licensing were used by the licensee in performing the AST radiological analyses. The NRC had also approved the use of these meteorology atmospheric dispersion values by Amendment Nos. 210 and 202, dated December 29, 2006 (for SONGS Units 2 and 3, respectively). Consistent with RG 1.183, Regulatory Position 4.1.7, no correction is made for depletion of the effluent plume by deposition on the ground.

The CR dose during a design-basis FHA-FHB, following permanent shutdown of SONGS Units 2 and 3, was based on no credit for the Control Room Emergency Air Cleanup System (CREACUS) and Control Room Isolation Signal (CRIS) and no gamma radiation shine from CREACUS charcoal and high-efficiency particulate air (HEPA) filters. Control room doses are evaluated at various CR unfiltered inflow (including in leakage) flow rates. The flow rates were varied from 500 cubic feet per minute (cfm) to 15,000 cfm, but only the bounding CR dose is reported. The SONGS site-specific 95th percentile meteorology atmospheric dispersion factors for the CR were used.

The licensee concluded that the radiological consequences at the EAB and LPZ and in the CR are within the dose criteria for DBAs specified in 10 CFR 50.67 and SRP Section 15.0.1. The licensee also concluded that the radiological consequences are less than the dose criteria specified in the EPA PAG Manual. The NRC staff reviewed the licensee's evaluation and performed confirmatory calculations. In performing this review, the NRC staff relied upon information provided by the licensee, as well as, NRC staff experience in performing similar reviews. The NRC staff reviewed the methods, parameters, and assumptions that the licensee used in its radiological dose consequence analyses and concludes that they are acceptable because they are consistent with the guidance provided in RG 1.183. Using the FHA-FHB analyses assumptions described above, the NRC staff's confirmatory analyses of the licensee's FHA-FHB yield results for the CR, EAB, and LPZ that are less than the RG 1.183 and SRP 15.0.1 dose acceptance criteria and would not exceed the EPA PAG recommendations at the EAB.

3.3 Spent Fuel Cask Drop Accident

A re-analysis of the spent fuel cask drop accidents specified in the UFSAR, Section 15.7.3.5, was performed with a cask load of up to 32 fuel assemblies and a minimum of 17 months of decay. The spent fuel cask drop event is evaluated based on the potential of the cask drop to cause a release of radioactive material. This includes consideration of the allowed travel paths of the casks, their lift heights, and the items onto which they can be dropped. Even though single-failure-proof cranes are used at SONGS Units 2 and 3 to lift a spent fuel transfer cask out of a cask pool, a drop can be postulated when the cask is placed on the upper shelf (i.e., step) of a cask pool when performing a yoke-lift change-out, prior to the transfer cask being welded closed. The spent fuel cask drop accident considered to bound the radiological consequences of a spent fuel transfer cask drop (due to a seismic event) is from the upper shelf in the cask pool back into the lower portion of the cask pool. During this postulated accident, the transfer cask is not restrained and could fall back into the lower portion of the cask pool if an earthquake occurs. The fuel rods from all 32 fuel assemblies present in a transfer cask are conservatively assumed to rupture on impact with the bottom of the cask pool. All of the radioactive iodine and noble gases present in the gap volumes of the spent fuel rods are assumed to be released from the unwelded transfer cask. As required by the AST Amendment Nos. 210 and 202, dated December 29, 2006 (for SONGS Units 2 and 3, respectively), the new analysis was performed by the licensee using the AST methodology, including TEDE criteria. The NRC staff concludes that the licensee's modelling of decay time is consistent with RG 1.183, Regulatory Position 3.1.

Other than the number of fuel assemblies considered to fail, the radiological consequence analysis model is identical to that of the FHA in the FHA-FHB (see Section 3.2 of this SE). The fission product inventory in the fuel rod gap of the damaged rods is assumed to be released instantaneously into the SFP. The SFP water level is required to be at least 23 feet over the top of the irradiated fuel assemblies seated in the storage racks, as controlled by TSs. Consistent with RG 1.183, Appendix B, Regulatory Position 4.1, the radioactive material that escapes from the SFP to the FHB is released to the environment over a 2-hour time period, ensuring that at least 99.9 percent of the gaseous activity will be released to the environment. Consistent with RG 1.183, Regulatory Position 5.3, the atmospheric dispersion factor values for the EAB and the LPZ that were approved by the NRC during initial facility licensing are used in performing the AST radiological analyses. The NRC had also approved use of these meteorology atmospheric dispersion values by Amendment Nos. 210 and 202 for SONGS Units 2 and 3, respectively. Consistent with RG 1.183, Regulatory Position 4.1.7, no correction is made for depletion of the effluent plume by deposition on the ground.

The licensee concluded that the radiological consequences at the EAB and LPZ and in the CR are within the dose criteria for the DBAs, as specified in 10 CFR 50.67. The licensee also concluded that the radiological consequences are less than the dose criteria specified in the EPA PAG Manual. The NRC staff reviewed the licensee's evaluation and performed confirmatory calculations. In performing this review, the NRC staff relied upon information provided by the licensee and NRC staff experience in performing similar reviews. The NRC staff reviewed the methods, parameters, and assumptions that the licensee used in its radiological dose consequence analyses and concludes that they are acceptable because they are consistent with the guidance provided in RG 1.183. Using the analyses assumptions

described above, the NRC staff's confirmatory analyses yielded results for the CR, EAB, and LPZ that were less than the RG 1.183 dose acceptance criteria and would not have exceeded the EPA PAG recommendations at the EAB.

3.4 Spent Fuel Pool Boiling Accident

The postulated loss of all SFP cooling is assumed to result in SFP boiling and release of a portion of the radionuclide inventory contained in the stored spent fuel assemblies and the SFP water. The re-evaluation of the radiological consequences for the SFP boiling event assumes a minimum of 17 months since the shutdown of SONGS Units 2 and 3. The licensee used the AST methodology in performing this evaluation. The NRC staff concludes that the licensee's modelling of decay time is consistent with RG 1.183, Regulatory Position 3.1.

The radiological consequence analysis does not differentiate between the activity release rates before and after the onset of SFP boiling. Noble gas, iodine and tritium activity present in the failed fuel rod gap spaces of fuel rods, stored within the SFP, is released to the SFP water at the noble gas, iodine, and tritium escape rate coefficients, with the added conservatism of an assumed spiking factor of 100. The noble gas and iodine fuel rod gap fractions are consistent with the AST methodology. The tritium fuel rod gap fraction is assumed to be the same as that for the majority of noble gas and iodine isotopes. Tritium activity present in the SFP water prior to the loss of SFP cooling, is assumed to be released at the SFP boiling rate for the duration of the event. Both before and after the onset of SFP boiling spent fuel noble gases, iodine and tritium gas escaping from the failed fuel rod gap spaces are assumed to be instantaneously released with no hold up or iodine partitioning in the SFP water. The SFP boiling rate is a function of the decay heat load and the heat of vaporization of water.

Following a loss of SFP cooling, activity releases from the spent fuel due to evaporation and boiling disperse to the CR, EAB, and LPZ locations. No credit is taken for activity retention within the FHB. No credit is taken for FHIS or filtration by the FHB PACUs. All activity escaping from the SFP is assumed to be instantaneously released to the environment and atmospherically dispersed to the CR and offsite dose receptors. No credit is taken for CRIS or CREACUS.

The SFP boiling accident consequence analysis uses the identical model used for the FHA-FHB (see Section 3.2 of this SE). Consistent with RG 1.183, Appendix B, Section 4.1, the radioactive material that escapes from the SFP to the FHB is released to the environment over a 2-hour time period, ensuring that at least 99.9 percent of the gaseous activity will be released to the environment. For conservatism, the CR dose is calculated for an individual at the CR outside air intake location.

Consistent with RG 1.183, Regulatory Position 5.3, the atmospheric dispersion factor values for the EAB and the LPZ, which were approved by the NRC during initial facility licensing, are used in performing the AST radiological analyses. The NRC staff had also approved the use of these meteorology atmospheric dispersion values by Amendment Nos. 210 and 202, dated December 29, 2006 (for SONGS Units 2 and 3, respectively). Consistent with RG 1.183,

Regulatory Position 4.1.7, no correction is made for depletion of the effluent plume by deposition on the ground.

The licensee concluded that the radiological consequences at the EAB, LPZ, and CR are within the dose criteria for DBAs, as specified in 10 CFR 50.67. The licensee also concluded that the radiological consequences are less than the dose criteria specified in the EPA PAG Manual. The NRC staff reviewed the licensee's evaluation and performed confirmatory calculations. In performing this review, the NRC staff relied upon information provided by the licensee, as well as NRC staff experience in performing similar reviews. The NRC staff reviewed the methods, parameters, and assumptions that the licensee used in its radiological dose consequence analyses and finds that they are acceptable because they are consistent with the guidance provided in RG 1.183. Using the analyses assumptions described above, the NRC staff's confirmatory analyses yielded results for the CR, EAB, and LPZ that are less than the RG 1.183 dose acceptance criteria and would not exceed the EPA PAG recommendations at the EAB.

3.5 Radioactive Waste System Leak or Failure (Release to Atmosphere) Accident

The radioactive waste system leak or failure (with release to atmosphere) accident analysis (UFSAR Section 15.7.3.2) was revised to calculate the EAB and LPZ doses using the AST methodology. As required by the AST Amendment Nos. 210 and 202 for SONGS Units 2 and 3, respectively, the evaluation includes TEDE dose criteria, and a revised offsite dose acceptance criterion of 100 mrem TEDE, as addressed in NRC RIS 2006-04. The evaluation does not assume any post-shutdown decay time.

Releases from the Liquid Radioactive Waste System considered rupture of: radwaste tanks, refueling water storage tanks, primary ion-exchangers, and the blowdown demineralizer neutralization sump line. The most limiting of these is defined as an unexpected and uncontrolled release of the radioactive liquid stored in a radwaste secondary tank. The radwaste secondary tanks are Seismic Category II, Quality Class III tanks at atmospheric pressure. Rupture of these tanks is considered a limiting fault. A radwaste secondary tank rupture would release the liquid contents into the auxiliary building (radwaste area). It is assumed that all of the radioactive fission gases and iodines are released to the outside atmosphere within 2 hours.

The dose analysis for persons located at the EAB and the LPZ considers the dose consequences of inhalation and submersion in a radioactive cloud, as described in RG 1.183. Activity released during the event is transported by atmospheric dispersion to the offsite EAB and LPZ dose receptors. Consistent with RG 1.183, Regulatory Position 5.3, the atmospheric dispersion factor values for the EAB and the LPZ, which were approved by the NRC during initial facility licensing, are used in performing the AST radiological analyses. The NRC staff had also approved use of these meteorology atmospheric dispersion values by Amendment Nos. 210 and 202 for SONGS Units 2 and 3, respectively. Consistent with RG 1.183, Regulatory Position 4.1.7, no correction is made for depletion of the effluent plume by deposition on the ground.

The licensee concluded that the radiological consequences are less than 100 mrem TEDE offsite dose criterion per RIS 2006-04. The licensee also concluded that the radiological consequences are less than the dose criteria specified in the EPA PAG Manual. The NRC staff reviewed the licensee's evaluation and performed confirmatory calculations. In performing this review, the NRC staff relied upon information provided by the licensee, as well as NRC staff experience in performing similar reviews. The NRC staff reviewed the methods, parameters, and assumptions that the licensee used in its radiological dose consequence analyses and concludes that they are acceptable because they are consistent with the guidance provided in RG 1.183. Using the analyses assumptions described above, the NRC staff's confirmatory analyses yielded results for the EAB, LPZ, and CR that are less than RG 1.183 dose acceptance criteria and are also less than the offisite dose criteria per RIS 2006-04 and would not exceed the EPA PAG recommendations at the EAB.

3.6 Accident Analysis Conclusions

The NRC staff reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological impacts of the proposed changes. The NRC staff finds that the licensee's analyses are acceptable because their analysis methods and assumptions are consistent with the guidance of RG 1.183. The NRC staff compared the doses estimated by the licensee to the applicable criteria and to the results of confirmatory analyses by the staff. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and CR doses due to postulated DBAs at SONGS will comply with the requirements of 10 CFR 50.67 and the guidance of RG 1.183, and 10 CFR Part 20, as addressed in NRC RIS 2006-04. The NRC staff finds, with respect to the consequences of the remaining DBAs at SONGS, that no CR dose limits will be exceeded and that any offsite radiological release will not exceed the EPA PAGs at the EAB.

3.7 Proposed TS Changes

3.7.1 Section 1.1, Definitions

The licensee proposed deleting the following definitions because they pertain to an operating reactor. Since SONGS Units 2 and 3 are permanently shut down and defueled, the definitions have no relevance and no longer apply:

> AXIAL SHAPE INDEX (ASI) – ASI shall be the power generated in the lower half of the core less the power generated in the upper half of the core, divided by the sum of the power generated in the lower and upper halves of the core.
>
> $$\mathrm{ASI} = \frac{\mathrm{lower-upper}}{\mathrm{lower+upper}}$$
>
> AZIMUTHAL POWER TILT (T_q) - AZIMUTHAL POWER TILT shall be the power asymmetry between azimuthally symmetric fuel assemblies.
>
> CHANNEL CALIBRATION – A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the

necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, display, and trip functions, and shall include the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace cross calibration of the sensing elements and normal calibration of the remaining adjustable devices in the channel. Whenever a sensing element is replaced, the next required inplace cross calibration consists of comparing the other sensing elements with the recently installed sensing element.

The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is calibrated.

CHANNEL CHECK – A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST - A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY, including required alarms, interlocks, display and trip functions;

b. Bistable channels (e.g., pressure switches and switch contacts) - the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY, including required alarm and trip functions; or

c. Digital computer channels - the use of diagnostic programs to test digital computer hardware and the injection of simulated process data into the channel to verify OPERABILITY, including alarm and trip functions.

The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

CORE ALTERATION - CORE ALTERATION shall be the movement or manipulation of any fuel, sources, reactivity control components, or other components, excluding control element assemblies (CEAs) withdrawn into the upper guide structure, affecting reactivity, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE

ALTERATIONS shall not preclude completion of movement of a component to a safe position.

CORE OPERATING LIMITS REPORT (COLR) - The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.7.1.5. Plant operation within these limits is addressed in individual Specifications.

DOSE EQUIVALENT I-131 - DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of 1-131, 1-132, 1-133, 1-134, and 1-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in ICRP-30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity."

Ē- AVERAGE DISINTEGRATION ENERGY - Ē shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 15 minutes, making up at least 95% of the total noniodine activity in the coolant.

ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME - The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

LEAKAGE – LEAKAGE shall be:

a. <u>Identified LEAKAGE</u>

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the

operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE).

b. Unidentified LEAKAGE

All LEAKAGE that is not identified LEAKAGE.

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MODE – A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

PHYSICS TESTS – PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Chapter 14, "Initial Test Program of the SONGS Units 2 and 3 UFSAR;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

RCS PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) - The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.7.1.6.

RATED THERMAL POWER (RTP) – RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3438 MWt.

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME - The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until electrical power to the CEAs drive mechanism is interrupted. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire

response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

SHUTDOWN MARGIN (SDM) – SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming:

a. All full length CEAs (shutdown and regulating) are fully inserted except for the single CEA of highest reactivity worth, which is assumed to be fully withdrawn. However, with all CEAs verified fully inserted by two independent means, it is not necessary to account for a stuck CEA in the SDM calculation. With any CEAs not capable of being fully inserted, the reactivity worth of these CEAs must be accounted for in the determination of SDM, and

b. There is no change in part length CEA position.

STAGGERED TEST BASIS - A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

THERMAL POWER – THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

In conjunction with deletion of the term "MODE," TS Table 1.1-1, "MODES," is also being deleted.

The NRC staff examined the TS definitions proposed for deletion and concluded that all the terms listed above are only meaningful to a reactor authorized to operate. Since SONGS Units 2 and 3 are permanently shut down and defueled, the NRC staff finds that the licensee's proposed change to delete these definitions from the TSs is acceptable.

In addition, the licensee proposed adding a definition for CERTIFIED FUEL HANDLER. The licensee proposed to define a certified fuel handler as:

CERTIFIED FUEL HANDLER – A CERTIFIED FUEL HANDLER is an individual who complies with provisions of the CERTIFIED FUEL HANDLER training program required by TS 5.3.2.

TS 5.3.2 states, "An NRC approved training and retraining program for the Certified Fuel Handlers shall be maintained." The NRC staff finds the definition of a Certified Fuel Handler

conforms to the usage contained in the Administrative Controls section of the SONGS Units 2 and 3 permanently defueled TSs and is consistent with the definition in 10 CFR Part 50 and is, therefore, acceptable.

3.7.2 Section 1.2, Logical Connectors

Section 1.2, "Logical Connectors," of the SONGS TSs provides an explanation of the use of logical connectors. Logical connectors are used in TSs to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TSs are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

The licensee proposed deleting Example 1.2-2 in this section of the SONGS Units 2 and 3 defueled TSs. Example 1.2-2 explains the use of multiple logical connectors and nested connectors in the Required Action section. The licensee states that Example 1.2-1 adequately explains the use of the logical connectors that remain in the proposed defueled TS.

The only logical connector retained in the defueled TS is contained in the Required Action section for renumbered LCO 3.1.2. This use of logical connectors is fully illustrated by Example 1.2-1 in Section 1.2. Therefore, the NRC staff finds that the licensee's proposed change to delete Example 1.2-2 from TS Section 1.2 is acceptable.

3.7.3 Section 1.3, Completion Times

Section 1.3, "Completion Times," of the SONGS TSs establishes the completion time convention throughout the TSs and provides guidance for its use. The licensee has proposed to replace each reference to "operation of the unit" and "unit" with the new terminology, "storage of fuel assemblies" and "facility," respectively, since operation of the unit is no longer permitted and safe storage of fuel assemblies is the primary objective of the permanently defueled TSs. In its February 23, 2015, response to the NRC staff's request for additional information (RAI), the licensee stated that the requirements in the defueled TSs are applicable to the storage of any fuel assembly, and are not limited to the safe storage of irradiated fuel assemblies. In addition, the licensee proposed to delete references to "MODE" to be consistent with the removal of these definitions from TSs and because this term is no longer used in the Required Actions of the subsequent remaining LCOs in the proposed SONGS Units 2 and 3 defueled TSs. The licensee also proposed to delete Examples 1.3-2 through 1.3-7 because these examples refer to activities that no longer pertain to a permanently defueled condition.

The proposed change is shown below, with a strikethrough of the current wording and highlighting of the proposed changes:

> BACKGROUND
>
> Limiting Condition [sic] for Operation (LCOs) specify minimum requirements for ensuring safe ~~operation of the unit~~ storage of fuel assemblies. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which

the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the ~~unit~~ facility is in a ~~MODE or~~ specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the ~~unit~~ facility is not within the LCO Applicability. ...

The licensee proposed to delete several paragraphs of the Description Section that discuss entry into multiple Conditions, subsequent discovery of additional inoperable equipment, and the effects on the total Completion Times.

The licensee proposed to modify the Example, as follows:

EXAMPLE~~S~~ The following example~~s~~ illustrates the use of Completion Times ~~with different types of Conditions and changing Conditions~~.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 ~~Be in MODE 3~~ Verify....	6 hours
	AND	
	B.2 ~~Be in MODE 5~~ Restore....	36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

> The Required Actions of Condition B are to ~~be in MODE 3~~ perform the verification within 6 hours AND perform the restoration ~~in MODE 5~~ within 36 hours. A total of 6 hours is allowed for performing the verification ~~reaching MODE 3~~ and a total of 36 hours (not 42 hours) is allowed for performing the restoration ~~reaching MODE 5~~ from the time that Condition B was entered. If verification is performed ~~MODE 3 is reached~~ within 3 hours, the time allowed for ~~reaching MODE 5~~ performing the restoration is the next 33 hours because the total time allowed for performing the restoration ~~reaching MODE 5~~ is 36 hours.

The NRC staff has reviewed the proposed wording changes to the TS 1.3 Completion Times guidance and has determined that they are consistent with the transition from an operating reactor to a permanently shutdown and defueled facility with a primary safety focus of storage of fuel assemblies. The proposed changes also remove references to operating MODES that are no longer permitted following the licensee's submittal of certifications in accordance with 10 CFR 50.82(a)(2).

Examples 1.3-2 through 1.3-7, which are proposed to be deleted, provide an explanation of the time requirements for transitioning into a MODE in which the requirements are not applicable associated with entry in TS 3.0.3, or provide an explanation of more complex arrangements of Required Actions and Completion Times beyond those retained in the defueled TSs. TS 3.0.3 is being deleted as discussed in Section 3.7.6 of this safety evaluation. The NRC staff finds that these examples are no longer necessary to understand and properly implement the remaining Required Actions and Completion Times.

For the reasons discussed above, the NRC staff has determined that the revision to Example 1.3-1 and the deletion of the remaining examples are appropriate. Therefore, the NRC staff finds that the licensee's proposed changes to TS Section 1.3 are acceptable.

3.7.4 Section 1.4, Frequency

Section 1.4, "Frequency," of the SONGS TSs, defines the proper use and application of Frequency requirements throughout the TSs. In this section, the licensee has proposed to delete the final paragraph in the description section. The final paragraph of the TS 1.4 description section discusses notes that modify the frequency of performance of some surveillances and the applicability of operating MODE entry restrictions of SR 3.0.4. None of the surveillances in the proposed TSs contain notes that modify the frequency of performance or the conditions during which the acceptance criteria must be satisfied. Therefore, this paragraph is not applicable to the proposed TS LCOs or SRs and may be deleted. Specifically, the following is being deleted:

> Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential

SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

The licensee proposed replacing the statement introducing the examples from "In these examples, the Applicability of the LCO ...is MODES 1, 2, and 3" with the statement "In these examples, the Applicability of the LCO...occurs whenever any fuel assembly is stored in the fuel storage pool." The reference to MODEs 1, 2, and 3 is no longer meaningful to the permanently shutdown and defueled condition at SONGS Units 2 and 3.

The licensee proposed to modify Examples 1.4-1 and 1.4-2 to be applicable to a facility that is permanently shutdown and defueled and proposed to delete Example 1.4-3, in its entirety.

A summary of the proposed changes is shown below, with a strikethrough of the current wording and highlighting of the proposed changes:

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
~~Perform CHANNEL CHECK~~. Verify. . .	~~12 hours~~ 7days

The licensee proposed to modify the discussion of Example 1.4-1 to reflect the 7 day frequency chosen for the example; to replace the word "unit" with the word "facility"; to delete the reference to MODEs; and to delete the reference to Example 1.4-3, which is also being deleted.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
~~Verify flow is within limits.~~ Verify...	Prior to moving a fuel assembly. . . ~~Once within 12 hours after~~

SURVEILLANCE	FREQUENCY
	~~≥ 25% RTP~~ ~~AND~~ ~~24 hours thereafter~~

The licensee proposed to revise the discussion of Example 1.4-2, as follows:

> Example 1.4-2 illustrates ~~has two Frequencies. The first is~~ a one time performance Frequency. ~~and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.~~
>
> ~~The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND").~~ This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. ~~"Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP~~.

The licensee also proposed to delete Example 1.4-3 because it is not needed in a permanently defueled condition. The example used a reference to operating reactor MODES that are no longer permitted at SONGS Units 2 and 3. Specifically, Example 1.4-3 refers to surveillances to be performed after power is greater than or equal to (≥) 25 percent rated thermal power (% RTP) and discusses MODE entry restrictions.

The licensee stated that the remaining Examples 1.4-1 and 1.4-2 (as revised) are sufficient to explain the application of TS frequency requirements for the permanently defueled SONGS Units 2 and 3, TSs.

The NRC staff has reviewed the proposed changes to TS Section 1.4 and has determined that they are appropriate for a permanently shutdown and defueled reactor. The proposed changes remove references to operating MODES or rated thermal power that are no longer permitted, following certification under the provisions of 10 CFR 50.82(a)(2). The deletion of the surveillance note referring to MODE entry restrictions of SR 3.0.4 is also appropriate since none of the surveillances in the proposed remaining defueled TSs contain notes that modify the

frequency of performance or the conditions during which the acceptance criteria must be satisfied. Therefore, the NRC staff finds that the licensee's proposed changes to TS Section 1.4 are acceptable.

3.7.5 Section 2.0, Safety Limits

Section 2.0, "Safety Limits," of the SONGS TSs, establishes safety limits (SLs), which are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity. SLs ensure that specified acceptable fuel design limits are not exceeded during steady state operation, normal operation transients, and anticipated operational occurrences (AOOs). The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere.

TS 2.1, "Safety Limits" (SLs), contains two separate specifications:

- TS 2.1.1, Reactor Core SLs; and
- TS 2.1.2, Reactor Coolant System Pressure SL

TS 2.2, "SL Violations," direct actions to be taken if an SL specified in TS 2.1 is violated.

The restrictions of the SLs defined in TS 2.1.1 prevent overheating of the fuel cladding, and possible cladding perforation, which could result in the release of fission products to the reactor coolant. TS 2.1.1 is applicable in MODES 1 and 2. TS 2.1.2 defines requirements on parameters to protect the integrity of the RCS against overpressure. TS 2.1.2 is applicable in MODES 1, 2, 3, 4, and 5.

The licensee proposed to delete the SLs specified in Section 2.0, because they are not applicable to the permanently shutdown and defueled status of the plant. The licensee stated that the SL TSs limit important process variables that are necessary to reasonably protect the integrity of certain physical barriers required for safe operation of the reactor in MODES 1 through 5. However, 10 CFR 50.82(a)(2) prohibits operation of the reactor or placing fuel in the reactor vessel. Therefore, the SL TSs only address specific process variables that are no longer applicable to SONGS Units 2 and 3.

The NRC staff examined the SLs and their TS Bases. There are three SLs in Section 2.0: a minimum limit on the departure from nucleate boiling ratio (DNBR); a maximum limit on the peak fuel centerline temperature to ensure fuel and cladding integrity; and a maximum RCS pressure to ensure RCS integrity. As stated in the "Bases for DNBR," a limit is placed on the DNBR, such that, no fuel clad damage would occur as a result of normal operation and AOOs. A limit is placed on peak fuel centerline temperature, such that, a hot fuel pellet in the core will not experience centerline fuel melting. The TS Bases for the maximum RCS pressure state that RCS integrity is an important barrier in the prevention of an uncontrolled release of fission products. Because SONGS Units 2 and 3 have permanently shut down and defueled, and the

licensee has submitted certifications under the provisions of 10 CFR 50.82(a)(2), placing fuel in the reactor vessel and resuming power operations are no longer authorized, therefore, SLs associated with the RCS are no longer applicable. In this condition, there will be no DNBR or peak fuel centerline temperature to be monitored. Based on these findings, the NRC staff concludes the SLs no longer apply. Since the SLs are no longer applicable, TS 2.2, which specifies the actions to be taken if a SL is violated, is no longer necessary. Therefore, the NRC staff finds the licensee's proposed changes to delete TSs 2.1 and 2.2 is acceptable.

3.7.6 Section 3.0, Limiting Condition for Operation and Surveillance Requirement Applicability

Section 3.0, "Limiting Condition for Operation (LCO) Applicability," and "Surveillance Requirement (SR) Applicability," of the SONGS TSs, contains the general requirements applicable to all LCOs and SRs and applies at all times unless otherwise stated in TSs.

LCO 3.0.1, establishes the applicability statement within each individual TS as the requirement for when the LCO shall be met. The licensee proposed to delete the reference to "MODES" and the reference to LCO 3.0.7. The licensee stated that reference to MODES is no longer relevant since SONGS Units 2 and 3 are permanently shut down and defueled. In addition, the deletion of reference to LCO 3.0.7 conforms to the request to delete this LCO from the SONGS Units 2 and 3 TSs, as discussed below.

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met. The licensee proposed to delete the references to LCO 3.0.5 and 3.0.6 to conform to the request to delete TS LCO 3.0.5 and 3.0.6 from the SONGS Units 2 and 3 TSs, as discussed below.

LCO 3.0.3 establishes the Actions that must be implemented when an LCO is not met and the associated Actions are not met, or an associated Action is not provided. LCO 3.0.3 requires placing the unit in a MODE or other specified condition in which the LCO does not apply. The licensee proposed to delete LCO 3.0.3, in its entirety, since it no longer applies. The regulations prohibit operation of the plant or placing fuel in the reactor vessel and references to operating MODES is no longer relevant.

LCO 3.0.4 establishes limitations on changing MODES or other specified conditions in the applicability when an LCO is not met. The licensee proposed to delete LCO 3.0.4 since SONGS Units 2 and 3 are permanently shut down and defueled and references to operating MODES are no longer relevant.

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with Actions. The licensee proposed to delete LCO 3.0.5, in its entirety. The licensee stated that LCO 3.0.5 is no longer necessary because the proposed defueled TSs do not contain requirements for declaring equipment inoperable or removing equipment from service.

LCO 3.0.6 establishes an exception to LCO 3.0.2 to allow the use of the Safety Function Determination Program. The licensee has proposed to delete that the Safety Function Determination Program, described in TS 5.5.13. The deletion of the Safety Function Determination Program is discussed in Section 3.7.17.4 of this SE. Consequently, the licensee has proposed to delete LCO 3.0.6, in its entirety, to conform the TSs to the proposed deletion of the Safety Function Determination Program.

LCO 3.0.7 pertains to certain reactor physics special tests and operations required to be performed at various times over the life of the unit. The licensee proposed to delete LCO 3.0.7, in its entirety, since reactor physics testing is no longer relevant to a permanently shutdown and defueled facility.

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This specification ensures that surveillances are performed to verify the operability of systems and components, and that variables are within specified limits. The licensee proposed to revise SR 3.0.1 to delete the reference to "MODES" since the reference to "MODES" is no longer relevant for the permanently shutdown and defueled condition at SONGS Units 2 and 3.

SR 3.0.2 permits a 25 percent extension of the interval specified in the Frequency, and establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval. The licensee proposed to delete the statements that pertain to Frequencies specified as "once" or "once per" and to delete the statement that "[e]xceptions to this Specification are stated in the individual Specifications." The licensee stated that the proposed defueled TSs no longer contain this type of Frequency or Completion Time.

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability. The licensee proposed to delete the reference to "MODE" since SONGS Units 2 and 3 is permanently shut down and defueled and operating MODES are no longer relevant.

The NRC staff has reviewed the proposed changes to TS LCO 3.0.1, SR 3.0.1, and SR 3.0.4 and determined that the changes acceptably removes the reference to "MODE," which is no longer applicable to a permanently shutdown and defueled facility. The staff has also reviewed the change to LCO 3.0.2 and determined that the change acceptably removes the reference to other TS requirements that are being deleted. Therefore, the NRC staff finds that the licensee's proposed changes to these LCOs and SRs are acceptable.

The NRC staff has reviewed the proposed deletion of TS LCOs 3.0.3 and LCO 3.0.4, and has determined that, consistent with the transition to a permanently shutdown and defueled facility, these LCOs are no relevant. Since 10 CFR 50.82(a)(2) prohibits the licensee from operating the plant or placing fuel in the reactor vessel, the references to "MODE," and the discussions about shutting down the unit, are no longer applicable. The NRC staff finds the licensee's

proposed changes to delete these LCOs, reflect the current SONGS Units 2 and 3 plant status, and, therefore, are acceptable.

The NRC staff has reviewed the proposed deletion of TS LCO 3.0.5. The NRC staff agrees that this specification is no longer necessary because the defueled TSs do not contain requirements to declare equipment inoperable or to remove equipment from service. Since LCO 3.0.5 is being deleted, the deletion of reference to LCO 3.0.5 in LCO 3.0.2 is also appropriate. The NRC staff finds this change appropriately reflects the requirements in the defueled TSs.

The NRC staff has reviewed the proposed deletion of TS LCO 3.0.6. The NRC staff agrees that there will not be any systems in the permanently defueled TSs that are interrelated with other systems that have TS LCOs (support and supported systems). As a result, the conditions of LCO 3.0.6 no longer apply. Therefore, the staff finds that it is appropriate to delete LCO 3.0.6. Since LCO 3.0.6 is being deleted, the deletion of reference to LCO 3.0.6 in LCO 3.0.2 is also acceptable.

The NRC staff has reviewed the proposed deletion of TS LCO 3.0.7. The facility operating licenses no longer permit emplacement of fuel in the reactor vessels or operation of the facility, and therefore, no physics testing will be performed in the future. Therefore, the provisions of LCO 3.0.7 are no longer necessary. The NRC staff finds that the deletion of LCO 3.0.7 appropriately reflects the permanently shutdown and defueled status of the facility.

The NRC staff has reviewed the proposed changes to TS SR 3.0.2. The NRC staff agrees that the statements to be deleted are no longer necessary because the defueled TSs do not contain Frequencies and Completion Times of the type described in the statements being deleted. Therefore, the NRC staff finds the proposed changes acceptable.

Based on the above, the NRC staff finds that the licensee's proposed changes to LCO 3.0.1, LCO 3.0.2, LCO 3.0.3, LCO 3.0.4, LCO 3.0.5, LCO 3.0.6, LCO 3.0.7, SR 3.0.1, SR 3.0.2, and SR 3.0.4 are acceptable.

3.7.7 Section 3.1, Reactivity Control Systems

Section 3.1, "Reactivity Control Systems," of SONGS Units 2 and 3 TSs, contain LCOs, Actions, and SRs that provide for appropriate control of process variables, design features, or operating restrictions that are required to protect the integrity of a fission product barrier. The following TSs for SONGS Units 2 and 3 are being proposed for deletion.

TS 3.1.1, "SHUTDOWN MARGIN (SDM) – T_{avg} > 200 °F [degrees Fahrenheit]," specifies the requirements to provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shut down and AOOs assuming the highest reactivity worth CEA remains fully withdrawn. TS 3.1.1 is applicable in "MODES 3 and 4."

TS 3.1.2, "SHUTDOWN MARGIN (SDM) - T_{avg} ≤ 200 °F," specifies the requirements to provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for

normal shut down and AOOs assuming the highest reactivity worth CEA remains fully withdrawn. TS 3.1.2 is applicable in "MODE 5."

TS 3.1.3, "Reactivity Balance," specifies the requirements for the comparison of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that DBAs and transient safety analyses remain valid. TS 3.1.3 is applicable in "MODES 1 and 2."

TS 3.1.4, "Moderator Temperature Coefficient (MTC)," specifies the requirements to ensure that core overheating and overcooling accidents will not violate the accident analysis assumptions. TS 3.1.4 is applicable in "MODES 1 and 2 with k_{eff} [effective multiplication factor] ≥ 1.0."

TS 3.1.5, "Control Element Assembly (CEA) Alignment," specifies the limits on shutdown and regulating CEA alignments to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved. TS 3.1.5 is applicable in "MODES 1 and 2."

TS 3.1.6, "Shutdown Control Element Assembly (CEA) Insertion Limits," specifies the limits on shutdown CEA insertion to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required shutdown margin following a reactor trip. TS 3.1.6 is applicable in "MODE 1, MODE 2 with any regulating CEA not fully inserted."

TS 3.1.7, "Regulating CEA Insertion Limits," specifies the limits on regulating CEA sequence and physical insertion for the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected CEA worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between regulating banks provides more uniform rates of reactivity insertion. TS 3.1.7 is applicable in "MODES 1 and 2."

TS 3.1.8, "Part Length Control Element Assembly (CEA) Insertion Limits," specifies the limits on part length CEA insertion for the function of preserving power distribution and ensuring that ejected CEA worth is maintained within limits. TS 3.1.8 is applicable in "MODE 1 > 20% RTP."

TS 3.1.9, "Boration Systems - Operating," establishes the requirements for borated water sources and flow paths to the RCS to ensure that sufficient borated water is available to maintain the reactor subcritical and provide makeup water to account for RCS shrinkage during cooldown to cold shutdown conditions. TS 3.1.9 is applicable in "MODES 1, 2, 3, and 4."

TS 3.1.10, "Boration Systems – Shutdown," establishes the requirements for borated water sources and flow paths to the RCS to ensure that sufficient borated water is available to maintain the reactor subcritical. TS 3.1.10 is applicable in "MODES 5 and 6."

TS 3.1.12, "Special Test Exception (STE) - Low Power Physics Testing," permits the relaxation of existing TS LCOs to allow the performance of PHYSICS TESTS. TS 3.1.12 is applicable in "MODES 2 and 3 during PHYSICS TESTS."

TS 3.1.13, "Special Test Exception (STE) - At Power Physics Testing," permits relaxation of existing TS LCOs to allow the performance of PHYSICS TESTS. TS 3.1.13 is applicable in "MODE 1 during PHYSICS TESTS."

TS 3.1.14, "Special Test Exceptions (STE) - Reactivity Coefficient Testing," permits relaxation of existing TS LCOs to allow the performance of PHYSICS TESTS. TS 3.1.14 is applicable in "MODE 1."

The NRC staff has reviewed the licensee's proposed change to delete the reactivity control system TSs for SONGS Units 2 and 3, and has determined that these TSs are only needed to provide the LCOs and SRs necessary to maintain reactivity parameters of fuel loaded into a reactor vessel within the margins of conditions encountered during normal operations, anticipated occurrences, and for DBAs. The reactivity control systems TSs are only important for a reactor authorized to operate or retain irradiated fuel in the reactor vessel. However, because 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactors or placing fuel in the reactor vessels at SONGS Units 2 and 3, there is no reactor core and the reactivity control systems are no longer relevant.

The NRC staff has also reviewed Section 3.1, the reactivity control systems TSs proposed for deletion (TS 3.1.1, TS 3.1.2, TS 3.1.3, TS 3.1.4, TS 3.1.5, TS 3.1.6, TS 3.1.7, TS 3.1.8, TS 3.1.9, TS 3.1.10, TS 3.1.12, TS 3.1.13, and TS 3.1.14), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. These TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 3.1, Reactivity Control Systems, is acceptable.

3.7.8 Section 3.2, Power Distribution Limits

Section 3.2, "Power Distribution Limits," of the SONGS Units 2 and 3 TSs, contains LCOs, Required Actions, and SRs that provide for appropriate control of process variables, design features, or operating restrictions that are required to control power distribution in the reactor, and in turn, protect the integrity of a fission product barrier. The following TSs are being proposed for deletion.

TS 3.2.1, "Linear Heat Rate (LHR)," specifies the limits based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. The limitation on LHR ensures that in the event of a loss-of-coolant accident (LOCA) the peak

temperature of the fuel cladding does not exceed 2200 °F. TS 3.2.1 is applicable in MODE 1 with THERMAL POWER > [greater than] 20% RTP.

TS 3.2.2, "Planar Radial Peaking Factors (F_{xy})," specifies the limits based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. Limiting of the calculated Planar Radial Peaking Factors to values equal to or greater than the measured Planar Radial Peaking Factors ensures that the calculated limits remain valid. TS 3.2.2 is applicable in "MODE 1 with THERMAL POWER > 20 % RTP."

TS 3.2.3, "AZIMUTHAL POWER TILT (Tq)," specifies the limits based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. The limitations on the Tq are provided to ensure that design operating margins are maintained. TS 3.2.3 is applicable in "MODE 1 with THERMAL POWER > 20% RTP."

TS 3.2.4, "Departure from Nucleate Boiling Ratio (DNBR)," specifies the limits based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. Operation of the core with a DNBR at, or above, this limit ensures that an acceptable minimum DNBR is maintained in the event of a loss of flow transient. TS 3.2.4 is applicable in "MODE 1 with THERMAL POWER > 20% RTP."

TS 3.2.5, "AXIAL SHAPE INDEX (ASI)," specifies the limits based on correlations between power peaking and certain measured variables used as inputs to the LHR and DNBR operating limits. The limitation on ASI ensures that the actual ASI value is maintained within the range of values used in the accident analysis. The ASI limits ensure that with T_q at its maximum upper limit, the DNBR does not drop below the DNBR safety limit for AOOs. TS 3.2.5 is applicable in "MODE 1 with THERMAL POWER > 20% RTP."

The NRC staff has reviewed the proposed deletion of the power distribution limits TSs and has determined that these TSs are only needed to provide the LCOs and SRs necessary to maintain reactor power and heat generation within the margins of conditions encountered during normal operation, anticipated occurrences, and for DBAs. The power distribution limits TSs are only important for a reactor authorized to operate. Because 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactors or placing fuel in the reactor vessels at SONGS Units 2 and 3, there is no reactor core generating power and the power distribution limits are no longer relevant.

The NRC staff has also reviewed Section 3.2, power distribution limits TSs proposed for deletion (TS 3.2.1, TS 3.2.2, TS 3.2.3, TS 3.2.4, and TS 3.2.5), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. These TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Unit 2 and Unit 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the

reactors or placing fuel in the reactor vessels and SONGS Unit 2 and Unit 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 3.2, Power Distribution Limits, is acceptable.

3.7.9 Section 3.3, Instrumentation

Section 3.3, "Instrumentation," of the SONGS Units 2 and 3 TSs, contains the LCOs, Actions, and SRs that provide for appropriate functional capability of sensing and control instrumentation required for the appropriate functional capability of plant equipment, and control of process variables, design features, or operating restrictions required for safe operation of the facility. The following TSs are being proposed for deletion.

TS 3.3.1, "Reactor Protective System (RPS) Instrumentation-Operating," specifies the requirements for the RPS instrumentation system to maintain the SLs during AOOs, and mitigates the consequences of DBAs in MODE 1 and MODE 2 (startup).

TS 3.3.2, "Reactor Protective System (RPS) Instrumentation – Shutdown," specifies the requirements for the RPS instrumentation system to maintain the SLs during all AOOs, and mitigates the consequences of DBAs in MODE 3 (hot standby), MODE 4 (hot shutdown), and MODE 5, when the reactor trip circuit breakers (RTCBs) are closed and the CEA drive system is capable of CEA withdrawal.

TS 3.3.3, Control Element Assembly Calculators (CEACs)," specifies the requirements to ensure the core protection calculators (CPCs) are either informed of individual CEA position within each subgroup, using one or other CEACs, or that appropriate conservatism is included in the CPC calculations to account for anticipated CEA deviations in MODES 1 and 2.

TS 3.3.4, "Reactor Protective System (RPS) Logic and Trip Initiation," specifies the requirements for RPS matrix logic, RPS initiation logic, RTBCs, and manual trip channels to effect automatic trip signals received from RPS instruments and to provide a means to manually trip the reactor in MODES 1 and 2, and in MODES 3, 4, and 5, when the RTCBs are closed and the CEA drive system is capable of CEA withdrawal.

TS 3.3.5, "Engineered Safety Features Actuation System (EFSAS) Instrumentation," specifies the requirements for the ESFAS Instrumentation to ensure ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the RCPB during AOOs and ensures acceptable consequences during accidents.

TS 3.3.6, "Engineered Safety Features Actuation System (EFSAS) Logic and Manual Trip," specifies the requirements for ESFAS Matrix Logic, ESFAS Initiation Logic, and Manual Trip channels to effect automatic ESFAS initiation received from ESFAS instruments and to provide a means to manually actuate an ESF system in MODES 1, 2, 3, and 4.

TS 3.3.11, "Post Accident Monitoring Instrumentation (PAMI)," is applicable in MODES 1, 2, and 3, and provides the operability requirements for accident monitoring instruments, which provides information required by the control room operators. The operability of the PAMI ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident.

TS 3.3.12, "Remote Shutdown System," is applicable in MODES 1, 2, and 3, and provides the operability requirements for instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room.

TS 3.3.13, "Source Range Monitoring Channels," is applicable in MODES 3, 4, and 5, and provides the operability requirements for source range monitoring instrumentation for indication, alarms, and reactor trips.

The NRC staff has reviewed the proposed deletion of the instrumentation TSs above. TS 3.3.1, TS 3.3.2, TS 3.3.3 and TS 3.3.4, are only necessary to maintain the ability of the RPS to automatically initiate a reactor scram to preserve the integrity of the fuel cladding, preserve the integrity of the primary system barrier, and minimize the energy which must be absorbed, and prevent criticality following a LOCA. TS 3.3.5 and TS 3.3.6 only concern instrumentation designed to mitigate accidents related to reactor operation. TS 3.3.11 and TS 3.3.12 only concern instrumentation to ensure there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident, and allow operators to take manual actions specified in the emergency operating procedures or to remotely shut down the reactor from a location other than the control room. TS 3.3.13 requires monitoring source range count rate level and detects a loss of SDM caused by a boron dilution event (detected as an increase in neutron flux). None of the instrumentation addressed by these TSs is needed by a reactor that has permanently shut down and defueled in accordance with 10 CFR 50.82(a)(2).

The NRC staff also has reviewed the above Section 3.3 instrumentation TSs that are proposed for deletion (TS 3.3.1, TS 3.3.2, TS 3.3.3, TS 3.3.4, TS 3.3.5, TS 3.3.6, TS 3.3.11, TS 3.3.12, and TS 3.3.13), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. These TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Unit 2 and Unit 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, the NRC staff finds that the licensee's proposed change to delete Section 3.3, instrumentation TS 3.3.1, TS 3.3.2, TS 3.3.3, TS 3.3.4, TS 3.3.5, TS 3.3.6, TS 3.3.11, TS 3.3.12, and TS 3.3.13 is acceptable.

TS 3.3.7, "Diesel Generator (DG) – Undervoltage Start," specifies the loss of voltage start (LOVS) instrumentation functions be operable in MODES 1, 2, 3, 4, and when the associated DG is required to be operable by LCO 3.8.2, AC Sources – Shutdown. TS 3.3.7 is proposed for deletion by the licensee.

TS 3.3.7 provides the LCO and SRs to ensure availability of backup safety-related alternating current (AC) power to the SSCs used to prevent or mitigate postulated accidents resulting in an uncontrolled release of radioactivity of DBAs as analyzed in the SONGS Unit 2 and 3 UFSARs. This TS LCO ensures the operability of instrumentation designed to detect an undervoltage on the safety-related AC electrical busses upon a loss of offsite power and start the emergency diesel generators (EDGs) to supply backup power to the AC busses. Since SONGS Units 2 and 3 are permanently shut down and defueled, SCE has analyzed the remaining DBAs at SONGS Units 2 and 3, and given the significant fuel decay period, found that the radiological consequences will not exceed the EPA's PAGs at the site boundary. The licensee's analysis also demonstrates that the dose consequences, within the CR, of any DBAs are acceptable without relying on SSCs remaining functional for accident mitigation except the passive fuel storage pool structure which will be maintained as a TS for SONGS.) SCE calculated the DBA radiological consequences assuming no credit for control room isolation or recirculation filtration and no credit for any accident mitigation by the auxiliary building ventilation system. Calculated doses at the EAB, LPZ, and CR are within 10 CFR 50.67 and RG 1.183 dose limits. Since the bounding accident analysis for the permanently defueled condition assumed no credit for control room post-accident recirculation system emergency ventilation or filtration for mitigation of radiological releases, the CREACUS is not required (see evaluation of TS 3.7.11 in Section 3.7.13 of this SE). Because CREACUS is not required to function to mitigate a DBA, backup electrical power required to support operation of CREACUS upon a loss of offsite power is unnecessary. Therefore the EDG loss of offsite power start instrumentation is also unnecessary for all postulated DBAs.

The NRC staff determined in Section 3.1 through 3.6 of this SE that with SONGS Units 2 and 3 permanently shut down and defueled and the irradiated fuel having decayed for a significant period, CREACUS is no longer needed or credited in the primary success path of a safety sequence analysis related the remaining DBAs at SONGS Units 2 and 3. Consequently, neither primary nor backup power to support operation of CREACUS is needed. Therefore, actuation instrumentation to start the backup power EDGs is no longer required to satisfy TS Criterion 3 for inclusion in TSs as a support or actuation system that is necessary for items in the primary success path to successfully function. The NRC staff has confirmed that there are no other DBAs analyzed in the SONGS Units 2 and 3 UFSAR that rely on this instrumentation system. Based on the above, the NRC staff finds that the licensee's proposed change to delete TS 3.3.7 is acceptable.

TS 3.3.8, "Containment Purge Isolation Signal (CPIS)," specifies the requirements for instrumentation designed to close the containment purge isolation valves upon a detection of high gaseous radiation in containment. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. TS 3.3.8 is applicable in MODES 1, 2, 3, and 4, during core alterations, and during movement of fuel assemblies within containment. TS 3.3.8 is proposed for deletion by the licensee.

This TS indicates MODES for which the TS is applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Unit 2 and Unit 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply. The staff also reviewed the non-MODE dependent applicability during core alterations, and during movement of fuel assemblies in containment. Because 10 CFR 50.82(a)(2) prohibits operation of the plant or placing fuel in the reactor vessel, the prohibition on placing fuel in the reactor vessel, it also precludes core alterations and the movement of fuel assemblies within containment.

The NRC staff also evaluated the proposed deletion of TS 3.3.8, to ensure that the LCO no longer satisfies the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff has determined that TS 3.3.8 only addresses specific plant systems, control of process variables, design features, or operating restrictions associated with the containment and are no longer needed or credited in the primary success path of a safety sequence analysis related the remaining DBAs at SONGS Units 2 and 3. Based on the above, the NRC staff finds that the licensee's proposed change to delete TS 3.3.8 is acceptable.

TS 3.3.9, "Control Room Isolation Signal (CRIS)," specifies the requirements to ensure instrumentation (actuation logic, manual trip, and gaseous radiation monitors) necessary to initiate CREACUS is operable. The CRIS terminates the normal supply of outside air to the CR and initiates actuation of the CREACUS to minimize operator radiation exposure. The radiation monitor actuation of the CREACUS in MODES 5 and 6 and during movement of fuel assemblies is the primary means to ensure control room habitability in the event of an FHA. TS 3.3.9 is applicable in MODES 1, 2, 3, 4, 5, 6, and during movement of fuel assemblies within containment and in the fuel storage pool. TS 3.3.9 is proposed for deletion by the licensee.

This TS indicates MODES for which the TS is applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

The NRC staff evaluated the proposed deletion of TS 3.3.9 to ensure that the LCO no longer satisfies the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The NRC staff also reviewed the non-MODE dependent applicability during movement of fuel assemblies within containment and in the fuel storage pool. As detailed in Sections 3.1 through 3.6 of this SE, the remaining accident analyses applicable to the permanently shutdown and defueled reactors of SONGS Units 2 and 3 show that the dose

consequences within the control room are acceptable. Furthermore, the analyses do not rely on the functioning of any SSCs to mitigate the postulated DBAs with the exception of the passive fuel storage pool structure.

The NRC staff evaluated the remaining DBAs that credited the CREACUS, and its support systems, that were previously relied upon to mitigate the CR, EAB or LPZ dose consequences during reactor operation. This includes the FHIS, the FHB PACU filtration system, and the CRIS. As discussed in the basis for deleting CREACUS TS 3.7.11, (see Section 3.7.13 of this SE), the CRIS is no longer required for providing airborne radiological protection for the control room operators in the event of a DBA. Since TS 3.3.9 exists solely to support CREACUS Operability, the elimination of the need for the CREACUS also obviates the need for its support systems. The deletion of the CREACUS TS 3.7.11 eliminates the need for the CRIS TS 3.3.9. Therefore, the NRC staff finds the CRIS isolation signal is no longer required and that the licensee's proposed change to delete TS 3.3.9 is acceptable.

3.7.10 Section 3.4, Reactor Coolant System

The RCS TSs of Section 3.4, "Reactor Coolant System (RCS)," for SONGS Units 2 and 3 contain the LCOs, Actions, and SRs that provides for appropriate control of process variables, design features, or operating restrictions needed for appropriate functional capability of RCS equipment required for safe operation of the facility. The following TSs are being proposed for deletion.

TS 3.4.1, "RCS DNB [Departure from Nucleate Boiling] (Pressure, Temperature, and Flow) Limits," specifies the process variables requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum DNBR will be met for each of the analyzed transients. TS 3.4.1 is applicable in MODE 1.

TS 3.4.2, "RCS Minimum Temperature for Criticality," specifies the requirements for RCS loop cold leg temperature (T_c) before the reactor can be made critical and while the reactor is critical. Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} > 1.0$) outside a temperature operating range of 522 °F to 558 °F, and to prevent operation in an unanalyzed condition. TS 3.4.2 is applicable in "MODE 1, THERMAL POWER ≤ 30% RTP and T_c < 535 °F, and in MODE 2, $K_{eff} \geq 1.0$ and T_c < 535 °F."

TS 3.4.3, "RCS Pressure and Temperature (P/T) Limits," specifies that the RCS pressure, RCS temperature and RCS heatup and cooldown rates shall be maintained within the limits as specified in the Pressure - Temperature Limits Report (PTLR). The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the RCPB. TS 3.4.3 is applicable at all times. The purpose for TS LCO 3.4.3 during normal operation of the RCS is to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. The RCS P/T limits in LCO 3.4.3 provide a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR Part 50, Appendix G. Although the P/T limits were developed to provide guidance for operation during heatup, or

cooldown, or inservice leak and hydrostatic testing, the applicability of these limits is at all times in keeping with the concern for nonductile failure.

TS 3.4.3.1, "Pressurizer Heatup and Cooldown Limits," requires that the pressurizer heatup and cooldown rates shall be maintained within the specified limits. The pressurizer is designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation. Therefore, TS 3.4.3.1 is applicable at all times.

TS 3.4.4, "RCS Loops - MODES 1 and 2," specifies the requirements to ensure heat removal capability of the RCS loops with the reactor in MODES 1 and 2. The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service. TS 3.4.4 is applicable in MODES 1 and 2.

TS 3.4.5, "RCS Loops - MODE 3," specifies the requirements to ensure heat removal capability of the RCS loops with the reactor in MODE 3. In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the SGs, to the secondary plant fluid. TS 3.4.5 is applicable in MODE 3.

TS 3.4.6, "RCS Loops - MODE 4," specifies the requirements to ensure heat removal capability of the RCS loops with the reactor in MODE 4. In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to the SGs or shutdown cooling (SDC) heat exchangers. TS 3.4.6 is applicable in MODE 4.

TS 3.4.7, "RCS Loops - MODE 5, Loops Filled," specifies the requirements to ensure heat removal capability of the RCS loops with the reactor in MODE 5 with the RCS loops filled with coolant. In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the SGs or SDC heat exchangers. While the principal means for decay heat removal is via the SDC heat exchangers, the SGs are specified as a backup means for redundancy. TS 3.4.7 is applicable in MODE 5 with the RCS loops filled.

TS 3.4.8, "RCS Loops - MODE 5, Loops Not Filled," specifies the requirements to ensure heat removal capability of the RCS loops with the reactor in MODE 5 with the RCS loops not filled with reactor coolant. In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the SDC heat exchangers. The SGs are not available as a heat sink when the loops are not filled. TS 3.4.8 is applicable in MODE 5 with the RCS loops not filled.

TS 3.4.9, "Pressurizer," specifies the OPERABILITY requirements for the RCS pressurizer. The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium

under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. TS 3.4.9 is applicable in MODES 1, 2, and 3.

TS 3.4.10, "Pressurizer Safety Valves," specifies the OPERABILITY and lift setpoint parameters for the pressurizer safety valves. The pressurizer safety valves provide, in conjunction with the reactor protection system, overpressure protection for the RCS. The pressurizer safety valves are designed to prevent the RCS from exceeding the system safety limit of 2750 pounds per square inch absolute (psia) in MODES 1, 2, and 3. In MODES 4, 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP) System. TS 3.4.10 is applicable in MODES 1, 2, and 3.

TS 3.4.12.1, "Low Temperature Overpressure Protection (LTOP) System, RCS Temperature ≤ PTLR Limit," specifies the requirements for controlling RCS pressure at low temperatures so the integrity of the RCPB is not compromised by violating the P/T limits of 10 CFR Part 50, Appendix G. TS LCO 3.4.12.1 provides RCS overpressure protection by minimizing coolant input capability and having adequate pressure relief capacity. In MODES 1, 2, and 3, the pressurizer safety valves will prevent RCS pressure from exceeding limits. In MODE 4 when the temperature of any RCS cold leg is less than or equal to the enable temperature specified in the PTLR, MODE 5, and MODE 6 when the reactor vessel head is on and the RCS is not vented, overpressure prevention falls to the OPERABLE SDC system relief valve or to a depressurized RCS and a sufficient sized RCS vent. When the reactor vessel head is off, overpressurization cannot occur.

TS 3.4.12.2, "Low Temperature Overpressure Protection (LTOP) System, RCS Temperature ≥ PTLR Limit," specifies requirements for controlling RCS pressure at low temperatures so the integrity of the RCPB is not compromised by violating the P/T limits of 10 CFR Part 50, Appendix G. TS LCO 3.4.12.2 provides RCS overpressure protection by having adequate pressure relief capacity. In MODES 1, 2, and 3 the pressurizer safety valves will prevent RCS pressure from exceeding limits. In MODE 4 when the temperature of all RCS cold legs are greater than the enable temperature specified in the PTLR, overpressure prevention falls to the OPERABLE SDC system relief valve or to an OPERABLE pressurizer code safety valve.

TS 3.4.13, "RCS Operational LEAKAGE," specifies the process variable limits and operating restrictions for RCS pressure boundary leakage, unidentified RCS leakage, identified RCS leakage, and primary to secondary leakage. RCS leakage is indicative of material deterioration, possibly of the RCS pressure boundary, which can affect the probability of a design basis event. The primary to secondary leakage limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures (SGTRs). TS 3.4.13 is applicable in MODES 1, 2, 3, and 4. In MODES 5 and 6, leakage limits are not required because the

reactor coolant pressure is far lower, resulting in lower stresses and reduced potential for leakage.

TS 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," specifies the process variable limits and operating restrictions for RCS PIV leakage. The regulations in 10 CFR 50.2, 10 CFR 50.55a(c), and 10 CFR Part 50, Appendix A, GDC 55, discuss RCPB valves, which are normally closed valves in series within the RCPB that separate the high pressure RCS from an attached low pressure system. Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems (intersystem LOCA). PIVs are provided to isolate the RCS from the following typically connected systems: SDC system; safety injection system; and the chemical and volume control system. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. TS 3.4.14 is applicable in MODES 1, 2, 3, and 4. In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for PIV leakage outside the containment.

TS 3.4.15, "RCS Leakage Detection Instrumentation," specifies the OPERABILITY requirements for RCS leakage detection instrumentation. Leakage detection systems are provided to detect significant RCPB degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, they provide an early indication or warning signal to permit proper evaluation of RCS leakage into the containment area. TS LCO 3.4.15 requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation. TS 3.4.15 is applicable in MODES 1, 2, 3, and 4.

TS 3.4.16, "RCS Specific Activity," specifies the process variable limits and operating restrictions for Dose Equivalent 1-131 and gross specific activity. The TS LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite doses meet the appropriate RG 1.183 acceptance criteria following a SGTR accident. TS 3.4.16 is applicable in MODES 1, 2, and MODE 3 with RCS average temperature ≥ 500 degrees F.

TS 3.4.17, "Steam Generator (SG) Tube Integrity," specifies the requirements to ensure the RCPB integrity function of the SG. The SGTR accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this specification. TS 3.4.17 is applicable in MODES 1, 2, 3, and 4.

The licensee proposed to delete all of Section 3.4 of the SONGS Units 2 and 3, RCS TSs, since all except TS 3.4.3, are only applicable to operating reactor MODES and do not apply to a permanently shutdown and defueled reactor. The NRC staff has reviewed these proposed changes and has determined that these TSs are only needed to provide the LCOs and SRs necessary to maintain functionality and integrity of the RCS pressure boundary. These TSs contain requirements for various RCS parameters such as: thermal limitations for heatup and cooldown rates during plant operation in order to operate within the analyzed requirements for stress intensity and fatigue limits for the reactor vessel; pressurization, which established and maintained an equilibrium under saturated conditions for pressure control to prevent bulk boiling

in the remainder of the RCS; coolant chemistry, which included limits on RCS activity to limit potential offsite doses due to postulated events and limits on RCS conductivity, chlorides, and pH to prevent stress-corrosion cracking; coolant leakage, which established primary system leakage limits to allow prompt identification and isolation of leaks before the integrity of the RCS pressure boundary was impaired; safety and relief valves, which specifies operability requirements for the safety and relief valves designed to prevent overpressurization of, and damage to, the primary system boundary; and structural integrity, which addresses the inservice inspection requirements of the primary system boundary components. All of these TSs are related to assuring the integrity of the RCS pressure boundary. The RCS TSs are only important for a reactor authorized to operate or retain irradiated fuel in the reactor vessel. However, because 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactors or placing fuel in the reactor vessels at SONGS Units 2 and 3, the RCS is no longer functional or used in any capacity.

Regarding the applicability of TS 3.4.3 and TS 3.4.3.1 at all times, the NRC staff notes that the RCS and pressurizer are drained and vented, to the extent possible, and consequently there is no longer any concern about exceeding the RCS and pressurizer P/T or cyclic limits. The requirements of 10 CFR Part 50, Appendix G, no longer apply to a permanently shutdown and defueled reactor because the RCPB will no longer be used as a fission product barrier. Therefore, TS 3.4.3 is no longer needed and may be deleted. Similarly, operating the unit within the fatigue analysis performed in accordance with the ASME Code Section III requirements no longer applies. Therefore, TS 3.4.3.1 is no longer needed and may also be deleted.

The NRC staff has also reviewed the RCS TSs proposed for deletion (TS 3.4.1, TS 3.4.2, TS 3.4.3, TS 3.4.3.1, TS 3.4.4, TS 3.4.5, TS 3.4.6, TS 3.4.7, TS 3.4.8, TS 3.4.9, TS 3.4.10, TS 3.4.12.1, TS 3.4.12.2, TS 3.4.13, TS 3.4.14, TS 3.4.15, TS 3.4.16, and TS 3.4.17), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this SE. The staff notes that these TSs indicate MODES for which these TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for a permanently shutdown and defueled reactor, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2) for SONGS Units 2 and 3, it is prohibited from operating the reactors or placing fuel in the reactor vessels and, therefore, SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply. Furthermore, because irradiated fuel has been permanently removed from the reactor pressure vessels, the RCS is no longer relevant as a fission product barrier.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 3.4, Reactor Coolant System, is acceptable.

3.7.11 Section 3.5, Emergency Core Cooling Systems (ECCS)

Section 3.5 of the SONGS Units 2 and 3 TSs, "Emergency Core Cooling Systems (ECCS)," contains LCOs that provide for appropriate functional capability of ECCS equipment required for

mitigation of DBAs or transients so as to protect the integrity of a fission product barrier. The following TSs are being proposed for deletion.

TS 3.5.1, "Safety Injection Tanks (SITs)," specifies the requirements for the SITs to ensure they are capable of supplying water to the reactor vessel during the blowdown phase of a LOCA, to provide inventory to help accomplish the refill phase that follows thereafter, and to provide RCS makeup for a small-break LOCA. TS 3.5.1 is applicable in MODES 1 and 2, and in MODE 3 with pressurizer pressure ≥ 715 psia.

TS 3.5.2, "ECCS - Operating," specifies the requirements for the ECCS trains so as to provide core cooling and negative reactivity to ensure that the reactor core is protected after a LOCA, CEA ejection accident, loss of secondary coolant accident (including uncontrolled steam release), and SGTR. The ECCS consists of the high pressure safety injection (HPSI) and the low pressure safety injection (LPSI) subsystems. TS 3.5.2 is applicable in MODES 1 and 2, and MODE 3 with pressurizer pressure ≥ 400 psia.

TS 3.5.3, "ECCS - Shutdown," specifies the requirements for ECCS with the reactor in MODE 3 with pressurizer pressure < 400 psia, and in MODE 4. In these MODES, an ECCS train is composed of a single HPSI subsystem. One OPERABLE ECCS train is acceptable without a single failure consideration, based on the stable reactivity condition of the reactor and the limited core cooling requirements.

TS 3.5.4, "Refueling Water Storage Tank (RWST)," specifies the requirements for RWST OPERABILITY. During accident conditions, the RWST provides a source of borated water to the ECCS and containment spray system pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown. TS 3.5.4 is applicable in MODES 1, 2, 3, and 4 because RWST OPERABILITY requirements are dictated by ECCS and containment spray system OPERABILITY requirements. Since both the ECCS and the containment spray system must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation.

TS 3.5.5, "Trisodium Phosphate (TSP) Dodecahydrate," specifies the requirements for TSP crystals to be placed in baskets on the floor of the containment building to ensure that iodine, which may be dissolved in the recirculated reactor cooling water following a LOCA, remains in solution. TSP also helps inhibit stress corrosion cracking (SCC) of austenitic stainless steel components in containment during the recirculation phase following an accident. TS 3.5.5 is applicable in MODES 1, 2, and 3, when the RCS is at elevated temperature and pressure, providing an energy potential for a LOCA.

The NRC staff has reviewed the proposed changes to the ECCS TSs and has determined that these TSs are only needed to provide the LCOs and SRs necessary to maintain functionality of the systems that provide emergency cooling to the reactor core and assure the appropriate functional capability ECCS required for mitigation of DBAs when the reactor is in MODES 1 through 4. These TSs includes multiple LCOs addressing the SITs, HPSI and LPSI subsystems; part of the ECCS, designed to provide adequate emergency cooling capability to

the reactor in the event of a LOCA; the RWST, designed to supply borated water to the ECCS during accident conditions; and the TSP baskets to help retain iodine in solution. All of these TSs are related to provide cooling for a reactor vessel core. Since SONGS Units 2 and 3 are permanently shut down and defueled, there are no accidents of any kind that would require emergency core cooling and the accidents that these systems and components were designed to mitigate are no longer possible.

The NRC staff also reviewed the ECCS TSs proposed for deletion (TS 3.5.1, TS 3.5.2, TS 3.5.3, TS 3.5.4, and TS 3.5.5), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff notes that these TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for a permanently shutdown and defueled reactor, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels, and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 3.5, Emergency Core Cooling Systems, is acceptable.

3.7.12 Section 3.6, Containment Systems

Section 3.6 of SONGS Units 2 and 3 TSs, "Containment Systems," contains the LCOs, Actions, and SRs that provide for appropriate control of process variables, design features, or operating restrictions required to protect the integrity of the containment as a fission product barrier; and appropriate functional capability of ESF equipment required for mitigation of DBAs or transients so as to protect the integrity of containment. The following TSs are being proposed for deletion from this section.

TS 3.6.1, "Containment," specifies the requirements for the containment to ensure it is capable of withstanding the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The containment steel liner and its penetrations establish the leakage limiting boundary of the containment. This TS provides the operating restrictions required to protect the integrity of the containment as a fission product barrier and limits the leakage of fission product radioactivity from the containment to the environment. TS 3.6.1 is applicable in MODES 1, 2, 3, and 4.

TS 3.6.2, "Containment Air Locks," specifies the requirements for the structural integrity and leak tightness of the containment air locks. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each containment air lock's structural integrity and leak tightness is essential to the successful mitigation of such an event. TS 3.6.2 is applicable in MODES 1, 2, 3, and 4.

TS 3.6.3, "Containment Isolation Valves," specifies the requirements for the isolation capability of the containment via the containment isolation valves. Containment isolation valves form a part of the containment boundary and their OPERABILITY supports leak tightness of the containment. TS 3.6.3 is applicable in MODES 1, 2, 3, and 4.

TS 3.6.4, "Containment Pressure," specifies the limitations on internal containment pressure. Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the maximum allowed containment internal pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the accidental actuation of the Containment Spray System. TS 3.6.4 is applicable in MODES 1, 2, 3, and 4.

TS 3.6.5, "Containment Air Temperature," specifies the limitations on containment average air temperature. Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the containment structural temperature is maintained below its design temperature and that required safety-related equipment will continue to perform its function. TS 3.6.5 is applicable in MODES 1, 2, 3, and 4.

TS 3.6.6.1, "Containment Spray and Cooling Systems," specifies the operability requirements for containment atmosphere cooling to limit post-accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduce the release of fission product radioactivity from containment to the environment, in the event of a DBA, to within limits. The containment spray system consists of two separate trains. Each train includes a containment spray pump, spray headers, valves and piping. The RWST supplies borated water to the containment spray system during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment sump. Two trains of containment cooling, each of sufficient capacity to supply 50 percent of the design cooling requirement, are provided. Two trains with two fan units each are supplied with cooling water from the component cooling water system. All four fans are required to furnish the design cooling capacity. Air is drawn into the coolers through the fans and discharged to the SG compartments and pressurizer compartment. TS 3.6.6.1 is applicable in MODES 1, 2, and 3.

TS 3.6.6.2, "Containment Cooling Systems," specifies the operability requirements for containment atmosphere cooling to limit post-accident pressure and temperature in containment to less than the design values. Reduction of containment pressure reduces the release of fission product radioactivity from containment to the environment, in the event of a DBA, to within limits. Two trains of containment cooling, each of sufficient capacity to supply 50 percent of the design cooling requirement, are provided. Two trains with two fan units each are supplied with cooling water from the component cooling water system. All four fans are required to

furnish the design cooling capacity. Air is drawn into the coolers through the fans and discharged to the SG compartments and pressurizer compartment. TS 3.6.6.2 is applicable in MODE 4, when a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature, requiring the operation of the containment cooling trains.

TS 3.6.8, "Containment Dome Air Circulators," specifies the requirements for the containment dome air circulators to reduce the potential for breach of the containment due to a hydrogen oxygen reaction. The dome air circulators accelerate the air mixing process between the upper dome space of the containment atmosphere during LOCA operations. They also prevent any hot spot air pockets during the containment cooling mode and avoid any hydrogen concentration in pocket areas. Two dome air circulator trains are required to be operable. Each train consists of two fans with their own motors and controls and is automatically initiated by a containment cooling actuation signal (CCAS). While each train has two fans, only one operable fan is required for the train to be operable, since each fan can provide the necessary flow rate to adequately mix the containment atmosphere. TS 3.6.8 is applicable in MODES 1 and 2.

The NRC staff has reviewed the licensee's proposed changes for Section 3.6 of the SONGS Units 2 and 3 TSs and has determined that the TSs are only needed to provide the LCOs and SRs necessary to maintain functionality of the containment. These TSs include multiple LCOs addressing containment integrity, which includes: containment pressure, containment air temperature, and containment air locks, which forms part of the containment pressure boundary; and containment isolation valves, designed to isolate the containment in the event of a LOCA to prevent the release of fission products to the atmosphere; containment spray and cooling, which limit post-accident pressure and temperature in containment; and dome air circulators that help reduce the potential hydrogen concentration pockets in containment following a design basis accident. All of these TSs are related to assuring the integrity of the containment as a fission product boundary. The containment TSs are only important for a reactor authorized to operate or retain irradiated fuel in the reactor vessel. However, because 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactors or placing fuel in the reactor vessels at SONGS Units 2 and 3, the containment SSCs are no longer functional or used in any capacity and the associated TSs are no longer meaningful.

The NRC staff also reviewed the containment TSs proposed for deletion (TS 3.6.1, TS 3.6.2, TS 3.6.3, TS 3.6.4, TS 3.6.5, TS 3.6.6.1, TS 3.6.6.2, and TS 3.6.8), to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff notes that these TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for a permanently shutdown and defueled reactor, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels, and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 3.6, Containment Systems, is acceptable.

3.7.13 Section 3.7, Plant Systems

Section 3.7 of the SONGS Units 2 and 3 TSs, "Plant Systems," contains the LCOs, Actions, and SRs that provide for appropriate functional capability of balance-of-plant equipment required for safe operation of the facility. This section contains operability requirements related to the steam generators, feedwater system, cooling water, ventilation, and spent fuel storage.

The licensee proposed deletion of the following LCOs in Section 3.7 of the SONGS Units 2 and 3 TSs:

TS 3.7.1, "Main Steam Safety Valves (MSSVs)," specifies the requirements for the MSSVs to ensure they are capable of providing overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the RCPB by providing a heat sink for the removal of energy from the RCS, if the preferred heat sink provided by the condenser and circulating water system, is not available. TS 3.7.1 is applicable in MODES 1, 2, and 3.

TS 3.7.2, "Main Steam Isolation Valves (MSIVs)," specifies the requirements for the MSIVs to ensure that they are capable of isolating steam flow from the secondary side of the SGs following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generator. One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the MSSVs, atmospheric dump valves, and auxiliary feedwater pump turbine steam supplies to prevent them from being isolated from the SGs by MSIV closure. Closing the MSIVs isolates each SG from the other, and isolates the turbine, steam bypass system, and other auxiliary steam supplies from the steam generators. TS 3.7.2 is applicable in MODES 1, 2, and 3 except when all MSIVs are closed and deactivated.

TS 3.7.3, "Main Feedwater Isolation Valves (MFIVs)," specifies the requirements for MFIVs. The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a HELB. Closure of the MFIVs terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream of the MFIVs will be mitigated by their closure. Closure of the MFIVs effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs. TS 3.7.3 is applicable in MODES 1, 2, and 3 except when MFIV is closed and deactivated.

TS 3.7.4, "Atmospheric Dump Valves (ADVs)," specifies the requirements for providing a method for cooling the unit to shutdown cooling system entry conditions, should the preferred heat sink via the steam bypass system to the condenser not be available. This is done in conjunction with the auxiliary feedwater (AFW) system providing cooling water from the condensate storage tank (CST). TS 3.7.4 is applicable in MODES 1, 2, and 3, and in MODE 4 when steam generator is relied upon for heat removal.

TS 3.7.5, "Auxiliary Feedwater (AFW) System," specifies the requirements to ensure that the AFW system automatically supplies feedwater to the steam generators to remove decay heat from the RCS upon the loss of normal feedwater supply. TS 3.7.5 is applicable in MODES 1, 2, and 3, and in MODE 4 when steam generator is relied upon for heat removal.

TS 3.7.6, "Condensate Storage Tank (CST T-121 and T-120)," specifies the requirements to ensure a safety grade source of water to the SGs for removing decay and sensible heat from the RCS. The CSTs provide a passive flow of water, by gravity, to the AFW System. TS 3.7.6 is applicable in MODES 1, 2, and 3, and in MODE 4 when steam generator is relied upon for heat removal.

TS 3.7.7, "Component Cooling Water (CCW) System," specifies the requirements to ensure that the CCW system provides a heat sink for the removal of process and operating heat from safety-related components during a DBA or transient. During normal operation, the CCW system also provides this function for various nonessential components. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the salt water cooling system, and thus to the environment. TS 3.7.7 is applicable in MODES 1, 2, 3, and 4.

TS 3.7.7.1, "Component Cooling Water (CCW) Safety Related Makeup System," specifies the requirements to ensure a safety-related CCW makeup system is available to maintain the water inventory in the CCW trains during a 7-day post-accident period. The safety-related makeup system is designed to supply water to the CCW trains following loss of normal CCW makeup from the nuclear service water system. For this purpose, sufficient water inventory is contained in the single primary plant makeup (PPMU) storage tank for both CCW trains. From the PPMU tank, water is transferred to the CCW return heads by two safety-related pumps. TS 3.7.7.1 is applicable in MODES 1, 2, 3, and 4.

TS 3.7.8, "Salt Water Cooling (SWC) System," specifies the requirements to ensure that the SWC system provides a heat sink for the removal of process and operating heat from safety-related components during a DBA or transient. During normal operation, and a normal shutdown, the SWC system also provides this function for various safety-related and nonsafety-related components. The safety-related function is covered by TS 3.7.8. TS 3.7.8 is applicable in MODES 1, 2, 3, and 4.

TS 3.7.10, "Emergency Chilled Water (ECW)," specifies the requirements to ensure that the ECW system provides a heat sink for the removal of process and operating heat from selected safety-related air handling systems during a DBA or transient. The design basis of the ECW system is to remove the post-accident heat load from ESF spaces following a DBA coincident with a loss of offsite power. Each train provides chilled water to the HVAC units at the design temperature and flow rate. TS 3.7.10 is applicable in MODES 1, 2, 3, and 4.

TS 3.7.19, "Secondary Specific Activity," specifies the limit on secondary coolant specific activity during power operation to minimize releases to the environment because of normal operation, AOOs, and accidents. The accident analysis of the main steam line break (MSLB) assumes an

initial secondary coolant specific activity used for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed the TEDE limit. TS 3.7.19 is applicable in MODES 1, 2, 3, and 4.

The NRC staff has reviewed the proposed changes to TSs 3.7.1 through TS 3.7.10, and TS 3.7.19 and has determined that these TSs are only necessary to assure the operability of certain plant systems during reactor operation. These TSs involve: MSSVs, which provide overpressure protection for the secondary system; MSIVs, which isolate steam flow from the secondary side of the steam generator following a MSLB; MFIVs, which isolate main feedwater flow to the secondary side of the steam generators following a HELB; ADVs, which provide a method for cooling the unit should the condenser not be available; AFW system, which supplies feedwater to the steam generators upon the loss of the normal feedwater supply; CSTs, which provide the preferred source of water to the steam generators for removing decay and sensible heat from the RCS; CCW system, CCW safety-related makeup system, and the SWC system, which provide a heat sink for the removal of process and operating heat from safety-related components during a DBA or transient to the ultimate heat sink; the ECW system that removes heat from ESF spaces through safety-related air handling systems; and secondary specific activity, which specifies a limit on secondary coolant specific activity during power operation.

The above TSs were intended to protect the fuel in the reactor from potential operational transients and accidents. However, 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactor or placing fuel in the reactor vessel. Consequently, there are no longer any transient or accident conditions that these systems and components protect against or mitigate. Therefore, the NRC staff finds the deletion of 3.7.1 through 3.7.10, as detailed above, is acceptable. TS 3.7.19 provides the operational limits on secondary coolant specific activity limiting the potential radiological consequences of an accident that could release pressurized steam from the SGs. Since 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactor or placing fuel in the reactor vessel, there is no source of heat available to pressurize the SGs and no source of activity. Therefore, the NRC staff finds the deletion of TS 3.7.19 is acceptable.

The NRC staff has also reviewed Section 3.7 of the SONGS Units 2 and 3, TS 3.7.1, TS 3.7.2, TS 3.7.3, TS 3.7.4, TS 3.7.5, TS 3.7.6, TS 3.7.7, TS 3.7.7.1, TS 3.7.8, TS 3.7.10, and TS 3.7.19 proposed for deletion to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff notes that these TSs indicate MODES for which the TSs are applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for permanently shutdown and defueled reactors, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Therefore, based on the evaluation above, the NRC staff finds that the licensee's proposed change to delete Plant Systems TS 3.7.1, TS 3.7.2, TS 3.7.3, TS 3.7.4, TS 3.7.5, TS 3.7.6, TS 3.7.7, TS 3.7.7.1, TS 3.7.8, TS 3.7.10 and 3.7.19, is acceptable.

TS 3.7.11, "Control Room Emergency Air Cleanup System (CREACUS)," specifies the requirements to ensure that the CREACUS provides a protected environment from which operators can control SONGS Units 2 and 3, following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. The CREACUS consists of two independent, redundant trains that recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CREACUS train consists of an emergency air conditioning unit, emergency ventilation air supply unit, emergency isolation dampers, and cooling coils and two cabinet coolers. Each emergency air conditioning unit includes a prefilter, a high efficiency particulate air (HEPA) filter, an activated carbon adsorber section for removal of gaseous activity (principally iodines), and a fan. A second bank of HEPA filters follows the adsorber section to collect carbon fines. Ductwork, motor-operated dampers, doors, barriers, and instrumentation also form part of the system. Upon receipt of the actuating signal, normal air supply to the CRE is isolated and the stream of ventilation air is recirculated through the system's filter trains. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers.

There are two CREACUS operational modes. Emergency mode is an operational mode when the control room is isolated to protect operational personnel from radioactive exposure through the duration of a DBA. Isolation mode is an operational mode when the CRE is isolated to protect operational personnel from toxic gases and smoke. Actuation of the CREACUS places the system into either of two separate states of operation, depending on the initiation signal. Actuation of the system to either the emergency mode or isolation mode of CREACUS operation closes the unfiltered-outside-air intake and unfiltered exhaust dampers and aligns the system for recirculation of air within the CRE through the redundant trains of HEPA and charcoal filters. The emergency mode also initiates pressurization of the CRE. Outside air is added to the air being recirculated from the CRE. Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the surrounding areas adjacent to the CRE boundary. The CRE supply and the outside air supply of the normal control room HVAC are monitored by radiation and toxic-gas detectors, respectively. One detector output above the setpoint will cause actuation of the emergency mode or isolation mode as required. The actions of the isolation mode are more restrictive, and will override the actions of the emergency mode of operation. TS 3.7.11 is applicable in MODES 1, 2, 3, 4, 5, and 6 and during movement of fuel assemblies in the containment or fuel storage pool.

When SONGS Units 2 and 3 were authorized to operate, the CREACUS provided a protected environment from which operators could control the units following postulated accidents involving an uncontrolled release of radioactivity, including an FHA. Prior to SONGS Units 2 and 3 permanently shutting down and defueling, the TSs for the CREACUS provided the LCOs and SRs necessary to maintain the control room environment following an accident. Specifically, during irradiated fuel movement, the CREACUS provided a protected environment from which operators can control the unit following a postulated uncontrolled release of radioactivity from an FHA. CRE will remain habitable during and following a DBA. In MODES 5

and 6, the CREACUS is required to cope with the release from a rupture of a waste gas tank. During movement of fuel assemblies, the CREACUS must be operable to cope with the release from an FHA.

The licensee provided information on the toxic gases isolation of CREACUS in Section 3.2.10.2.3 of the licensee's permanently defueled technical specification amendment request. Specifically, per the NRC's SE associated with the issuance of SONGS License Amendment Nos. 127 and 116 for Units 2 and 3, respectively dated February 9, 1996 (ADAMS Accession No. ML021990684), the toxic gas isolation of CREACUS is not relied on to prevent or mitigate a design basis accident or transient because the plant design includes other means to safely shut down the plant if the control room becomes uninhabitable. As such, the toxic gas isolation instrumentation was relocated from the TS and placed in the Licensee Controlled Specifications with an applicability of MODES 1, 2, 3, 4, 5, and 6. Since an NRC SE has already accepted the removal of toxic gas isolation of CREACUS from the TSs, a new NRC staff determination is not required. The staff concludes that automatic toxic gas isolation of CREACUS is not required during movement of fuel assemblies in the fuel storage pool at the permanently defueled SONGS Units 2 and 3.

With the termination of reactor operations at SONGS Units 2 and 3 and the permanent removal of the fuel from the reactor core in each unit, the postulated accidents involving failure or malfunction of the reactor, RCS, or secondary system are no longer applicable. While there are no transients that continue to apply to SONGS Units 2 and 3, there are still postulated DBAs. As discussed in Sections 3.1 through 3.6 of this SE, the remaining DBAs applicable to the defueled reactors of SONGS Units 2 and 3 show that the dose consequences are acceptable without relying on SSCs remaining functional for accident mitigation during and following the event, with the exception of the SFP structure.

The NRC staff evaluated these accident analyses and confirmed that no ESF system is used to mitigate the CR, EAB, or LPZ dose consequences. This includes no credit for the FHIS, the PACU filtration system, the CRIS and the CREACUS. Since SONGS Units 2 and 3 are permanently shutdown and defueled, and greater than 17 months of decay time has elapsed since permanent shut down, the remaining DBAs applicable to the facility demonstrate that the dose consequences within the CR are acceptable without relying on SSCs remaining functional for accident mitigation, including an FHA in the FHB. (The one exception to this is the continued function of the passive fuel storage pool structure, which will be maintained as a TS for SONGS Units 2 and 3.)

In summary, the radiological consequences of the remaining DBAs for SONGS Units 2 and 3 assume no credit for CR isolation or recirculation filtration and no credit for any accident mitigation by the FHB ventilation system. Calculated doses at the EAB, LPZ, and CR are within 10 CFR Part 50.67 limits, and RG 1.183 dose limits. Since the DBA accident analysis for SONGS Units 2 and 3 assumed no credit for control room post-accident recirculation system emergency ventilation or filtration, the CREACUS is no longer required. Therefore, isolation of the CRE via the CRIS and CREACUS is not necessary for any of the postulated DBAs. As noted before, the intent of Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) is to capture into TSs those SSCs that are part of the primary success path of a safety sequence analysis. With SONGS

Units 2 and 3 permanently shutdown and defueled, and the irradiated fuel having decayed for a minimum period of 17 months, the CREACUS is no longer needed or credited in the primary success path of a safety sequence analysis related to an accident. Since the radiological consequences of the accident analyses are within the appropriate acceptance criteria without credit for the CREACUS, the NRC staff finds that the licensee's proposed change to delete TS 3.7.11, is acceptable.

The licensee intends to retain TS 3.7.16, TS 3.7.17, and TS 3.7.18 but revise these TSs to delete the REQUIRED ACTIONS note that states that LCO 3.0.3 is not applicable. LCO 3.0.3 is being deleted from the SONGS Units 2 and 3 TSs and removal of a reference to TS 3.0.3 is a conforming change. In addition, with the deletion of all TSs in Section 3.1 through 3.6, the licensee also proposes to renumber these TSs to 3.1.1 to 3.1.3, respectively

TS 3.7.16, "Fuel Storage Pool Water Level," specifies the requirements to ensure that the minimum water level in the SFP meets the assumptions of iodine decontamination factors following an FHA. The water also provides shielding during the movement of spent fuel. This TS is applicable during movement of irradiated fuel assemblies in the SFP. The licensee has proposed to retain this TS in the permanently defueled TSs essentially unchanged. The Note in Required Action A.1 (LCO 3.0.3 is not applicable), is being deleted to conform to the deletion of TS LCO 3.0.3. The licensee has also proposed to renumber this TS as 3.1.1, based on the proposed deletion of all the preceding TSs.

Criterion 2 of 10 CFR 50.36(c)(2)(ii)(B) states that TS LCOs must be established for a "process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier." The purpose of this criterion is to capture those process variables that have initial values assumed in the DBA. TS 3.7.16, "Fuel Storage Pool Water Level," specifies the TS required LCOs and SRs that ensure the minimum water level in the SFP meets the assumptions of iodine decontamination factors following an FHA or cask drop accident.

SCE's analysis of the postulated FHA or cask drop accident assumes that there is at least 23 feet of water between the top of the damaged fuel assemblies and the fuel pool surface. The gap activity in the damaged rods is assumed to be instantaneously released into the SFP. Radionuclides in the gap release are assumed to be filtered by the 23 feet of water before emerging from the SFP. The activity exhaust rate from the auxiliary building is established to complete the release in 2 hours, as required by RG 1.183, but does not credit the auxiliary building ventilation for any mitigation of the release.

Since the 23-foot water level of the SFP is an initial condition of the FHA and the cask drop DBA, it satisfies Criterion 2 for inclusion in TSs and is being retained for SONGS Units 2 and 3 in their permanently shutdown and defueled condition. The amendment request by SCE does not involve any change to the technical language in the TS. The discussion in this evaluation of the SFP water level TS is provided only for completeness since the SFP water level is an important initial condition in the FHA and cask drop accident analysis and will continue to be part of the SONGS TSs.

TS 3.7.17, "Fuel Storage Pool Boron Concentration," specifies the requirements to ensure that the SFP boron concentration is > 2000 parts per million (ppm). The specified concentration of dissolved boron in the SFP preserves the assumptions used in the analyses of the potential critical accident scenarios as described in the criticality analysis of record, which is that a minimum of 2000 ppm of boron is needed to ensure that criticality does not occur during the worst case fuel loading accident. This concentration of dissolved boron is the minimum required for fuel assembly storage and movement within the spent fuel pool. This TS is applicable whenever fuel assemblies are stored in the spent fuel pool. This TS is being retained in the permanently defueled TS essentially unchanged. The Note in Required Action A.1 (LCO 3.0.3 is not applicable), is being deleted to conform to the deletion of TS LCO 3.0.3. The licensee has also proposed to renumber this TS as 3.1.2, based on the proposed deletion of all the preceding TSs.

TS 3.7.18, "Spent Fuel Assembly Storage," specifies the restrictions on the placement of fuel assemblies within the SFP, in accordance with Figure 3.1.3-1 through Figure 3.1.3-4 in the accompanying LCO, to ensure the keff of the SFP will always remain < 0.95, assuming the pool to be flooded with unborated water. This TS applies whenever any fuel assembly is stored in the spent fuel pool. TS 3.7.18 is being retained in the permanently defueled TS essentially unchanged. The Note in Required Action A.1 (LCO 3.0.3 is not applicable), is being deleted to conform to the deletion of TS LCO 3.0.3. The licensee has also proposed to renumber this TS as 3.1.3, based on the proposed deletion of all the preceding TSs.

The NRC staff reviewed the proposed deletion of the reference to LCO 3.0.3 in the Required Actions Note in TS 3.7.16, TS 3.7.17, and TS 3.7.18. The staff finds that deletion of the Note, "LCO 3.0.3 is not applicable," in each of these TSs is appropriate and the conforming change to the deletion of TS LCO 3.0.3, as discussed in Section 3.7.6 of this SE. Therefore, the staff finds that the licensee's proposed change to delete the reference to LCO 3.0.3 in TS 3.7.16, TS 3.7.17, and TS 3.7.18 (renumber as TS 3.1.1, TS 3.1.2, and TS 3.1.3, respectively – see below), is acceptable.

The NRC staff also reviewed the proposed change to renumber TS 3.7.16, 3.7.17, and TS 3.7.18, to TS 3.1.1, TS 3.1.2, and TS 3.1.3, respectively, and found the change to be editorial and conforming to the overall changes to the TSs. Therefore, the NRC staff finds that the licensee's proposed renumbering of the TSs is acceptable.

3.7.14 Section 3.8, Electrical Power Systems

The licensee proposed to delete SONGS Units 2 and 3 electrical power systems TS 3.8.1, TS 3.8.4, TS 3.8.7, and TS 3.8.9, since these TSs are MODE dependent and only applicable to an operating reactor. Therefore, these TSs do not apply to the permanently shutdown and defueled condition of SONGS Units 2 and 3.

TS 3.8.1, "AC [Alternating Current] Sources - Operating," specifies the requirements to ensure that the offsite power sources (normal preferred and alternate preferred power sources), and the standby power sources (Train A and Train B DGs), provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that

the fuel, RCS, and containment design limits are not exceeded. TS 3.8.1 is applicable in MODES 1, 2, 3, and 4.

TS 3.8.4, "DC [Direct Current] Sources - Operating," specifies the requirements to ensure that the DC electrical power subsystems (with each subsystem consisting of one battery, the required battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the subsystem) are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an AOO or postulated DBA. TS 3.8.4 is applicable in MODES 1, 2, 3, and 4.

TS 3.8.7, "Inverters - Operating," specifies the requirements to ensure that required inverters are OPERABLE such that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. These requirements include the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, RCS, and containment design limits are not exceeded. TS 3.8.7 is applicable in MODES 1, 2, 3, and 4.

TS 3.8.9, "Distribution Systems - Operating," specifies the requirements to ensure availability of AC, DC, and AC instrument bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an AOO or a postulated DBA. The AC, DC, and AC vital electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. TS 3.8.9 is applicable in MODES 1, 2, 3, and 4.

The NRC staff has reviewed the SONGS Units 2 and 3 electrical power systems LCOs in TS 3.8.1, TS 3.8.4, TS 3.8.7, and TS 3.8.9, which have been proposed for deletion, to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff notes that these TSs indicate MODES for which the TS is applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for the permanently shutdown and defueled reactors, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels. Therefore, SONGS Units 2 and 3 are no longer in a configuration or a condition under which these TS MODES apply. Based on the above, the staff finds the deletion of TS 3.8.1, TS 3.8.4, TS 3.8.7, and TS 3.8.9 from TS Section 3.8, Electrical Systems, is acceptable.

The licensee has also proposed to delete SONGS Units 2 and 3 electrical power systems TS 3.8.2, TS 3.8.3, TS 3.8.5, TS 3.8.6, TS 3.8.8, and TS 3.8.10, based on the MODE dependent applicably of these TSs. However, these TSs are also directly applicable during the movement of irradiated fuel assemblies or are support systems for TSs required during the movement of irradiated fuel assemblies. The following evaluations of these electrical power systems TSs assess the licensee's justification as to why these TSs do not apply to the

permanently shutdown and defueled condition of SONGS Units 2 and 3 during movement of irradiated fuel assemblies.

TS 3.8.2, "AC Sources - Shutdown," specifies the requirements to ensure that the offsite power sources (normal preferred and alternate preferred power sources), and the standby power sources (Train A and Train B DGs), provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. TS 3.8.2 is applicable during MODES 5 and 6 and during movement of fuel assemblies in containment or in the fuel storage pool.

TS 3.8.3, "Diesel Fuel Oil, Lube Oil, and Starting Air," provides for proper operation of the DGs, by specifying the parameters and ensuring there will be sufficient quantity and proper quality of the fuel oil, lube oil, and starting air systems. Stored diesel fuel oil is required to have sufficient supply for 7 days of rated load operation for each DG. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate each DG at rated load for 7 days. Lastly, each DG is equipped with two air start systems, which have adequate capacity for five successive start attempts on the DG without recharging the air start receivers. TS 3.8.3 is applicable whenever the DGs are required to be operable.

TS 3.8.5, "DC Sources Shutdown," specifies the requirements to ensure availability of the DC electrical power system and subsystems (with each subsystem consisting of one battery, required battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the subsystem), in order to provide normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching. TS 3.8.5 is applicable during MODES 5 and 6 and during movement of fuel assemblies in containment or in the fuel storage pool.

TS 3.8.6, "Battery Parameters," specifies the requirements to ensure the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC power subsystem batteries. Battery parameters are required solely for the support of the associated DC electrical power subsystems (per TS 3.8.4 and TS 3.8.5). Therefore, battery parameter limits are only required (and TS 3.8.6 is only applicable) when the DC electrical power source is required to be operable.

TS 3.8.8, "Inverters – Shutdown," specifies the requirements to ensure stability and reliability of the preferred source of power for the 120 Volt AC vital buses. The inverters can be powered from an internal AC source/rectifier or from the station battery. The inverter provides an uninterruptible power source for the safety-related instrumentation and controls. TS 3.8.8 is applicable during MODES 5 and 6 and during movement of fuel assemblies within containment or in the fuel storage pool.

TS 3.8.10, "Distribution Systems - Shutdown," specifies the requirements for the onsite AC, DC, and AC instrument bus electrical power distribution systems. The TS specifies sufficient capacity, capability, redundancy, and reliability of the distribution system to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design

limits are not exceeded. TS 3.8.10 is applicable during MODES 5 and 6 and during movement of fuel assemblies within containment or in the fuel storage pool.

The SONGS Unit 2 and 3 TS Basis documents indicates that the shutdown electrical power systems TS 3.8.2, TS 3.8.3, TS 3.8.5, TS 3.8.6, TS 3.8.8, and TS 3.8.10 provide assurance that:

a. The units can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the units status; and

c Adequate AC electrical power is provided to mitigate events postulated during shut down, such as an FHA.

The NRC staff has reviewed the SONGS Units 2 and 3 shutdown electrical power systems TSs (TS 3.8.2, TS 3.8.3, TS 3.8.5, TS 3.8.6, TS 3.8.8, and TS 3.8.10), which have been proposed for deletion, to ensure that these LCOs no longer satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The staff notes that these TSs indicate MODES for which the TS is applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for the permanently shutdown and defueled reactors, such as SONGS Units 2 and 3, has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactors or placing fuel in the reactor vessels and SONGS Units 2 and 3 is no longer in a configuration or a condition under which these TS MODES apply. Based on the above, the NRC staff finds that the licensee's proposed change to delete TS 3.8.2, TS 3.8.3, TS 3.8.5, TS 3.8.6, TS 3.8.8, and TS 3.8.10, from TS Section 3.8, Electrical Systems, for MODES 5 and 6, is acceptable.

The NRC staff also reviewed the non-MODE dependent applicability during movement of fuel assemblies within containment and in the fuel storage pool. Because 10 CFR 50.82(a)(2) prohibits operation of the plant or placing fuel in the reactor vessel, the prohibition on placing fuel in the reactor vessel, it also precludes core alterations and the movement of fuel assemblies within containment. Therefore, these TSs are no longer needed during movement of fuel assemblies within containment.

As detailed in Sections 3.1 through 3.6 of this SE, the remaining accident analyses applicable to the permanently shutdown and defueled reactors of SONGS Units 2 and 3 show that the dose consequences within the control room are acceptable without relying on SSCs remaining functional for accident mitigation during any of the remaining DBAs, including FHAs. (The one exception to this is the continued function of the passive fuel storage pool structure, which will be maintained as a TS for SONGS).

For TS 3.8.2, AC Sources – Shutdown, the FHA is the applicable DBA related to the TS requirement for functional capability of AC sources (offsite power and DGs) during the TS

specified condition of during movement of fuel assemblies in the fuel storage pool. Because the FHA analysis, and the other DBAs identified for SONGS Units 2 and 3, do not rely on normal or emergency power for accident mitigation (including any need for providing airborne radiological protection), the AC sources are not required during movement of fuel assemblies in the fuel storage pool for mitigation of a potential FHA or any of the other DBAs. Specifically, the accident analyses show that the dose consequences are acceptable without relying on any SSCs to remain functional during and following the postulated events, with the exception of the SFP support structure. Therefore, during movement of fuel assemblies in the fuel storage pool, there are no systems that function or actuate and are credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the DBA. As such, the requirement for AC sources is no longer necessary because there are no design-basis events that rely on AC sources for mitigation. Consequently, AC sources no longer meet the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) and can be removed from TSs. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.2, during movement of fuel assemblies in the fuel storage pool, is acceptable.

The NRC staff has reviewed the need for TS 3.8.3, Diesel Fuel Oil, Lube Oil, and Starting Air, during movement of fuel assemblies in the fuel storage pool. Since TS 3.8.3 exists solely to support the DG requirements of TS 3.8.1 and TS 3.8.2, the deletion of these TSs is consistent with the elimination of the need for DGs and also eliminates the need for the DG support systems. The NRC staff has determined that the requirement for DGs and associated supporting TSs are no longer necessary because the remaining DBAs for SONGS Units 2 and 3 do not rely on the DGs for mitigation. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.3, during movement of fuel assemblies in the fuel storage pool, is acceptable.

The NRC staff has reviewed the need for TS 3.8.5, DC Sources – Shutdown, during movement of fuel assemblies in the fuel storage pool. Because the FHA analysis, and the other DBAs identified for SONGS Units 2 and 3, do not rely on safety-related DC sources of electrical power for accident mitigation (including any need for providing airborne radiological protection), the DC sources are not required during movement of fuel assemblies in the fuel storage pool for mitigation of a potential FHA or any of the other DBAs. Specifically, the accident analyses show that the dose consequences are acceptable without relying on any SSCs to remain functional during and following the postulated events. Therefore, during movement of fuel assemblies in the fuel storage pool, there are no systems that function or actuate and are credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the DBA. As such, the requirement for DC sources is no longer necessary because there are no design-basis events that rely on DC sources for mitigation. Consequently, DC sources no longer meet the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) and can be removed from TSs. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.5, during movement of fuel assemblies in the fuel storage pool, is acceptable.

The NRC staff has reviewed the need for TS 3.8.6, Battery Parameters, during movement of fuel assemblies in the fuel storage pool. Since TS 3.8.6 exists solely to support the DC source requirements of TS 3.8.4 and TS 3.8.5, the deletion of these TSs is consistent with the elimination of the need for DC sources and also obviates the need for the battery support

systems. The staff has determined that the requirement for DC sources and associated supporting TSs are no longer necessary because the remaining DBAs for SONGS Units 2 and 3 do not rely on the DC sources for mitigation. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.6, battery parameters, during movement of fuel assemblies in the fuel storage pool, is acceptable.

The NRC staff has reviewed the need for TS 3.8.8, Inverters – Shutdown, during movement of fuel assemblies in the fuel storage pool. Because the FHA analysis, and the other DBAs identified for SONGS Units 2 and 3 do not rely on inverters or the safety-related 120 Volt AC electrical power for accident mitigation (including any need for providing airborne radiological protection), the inverters are not required during movement of fuel assemblies in the fuel storage pool for mitigation of a potential FHA or any of the other DBAs. Specifically, the accident analyses show that the dose consequences are acceptable without relying on any SSCs to remain functional during and following the postulated events, with the exception of the SFP support structure. Therefore, during movement of fuel assemblies in the fuel storage pool, there are no systems that function or actuate and are credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the DBA. As such, the requirement for inverters is no longer necessary because there are no design-basis events that rely on inverters for mitigation. Consequently, inverters no longer meet the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) and can be removed from TSs. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.8, during movement of fuel assemblies in the fuel storage pool, is acceptable.

The NRC staff has reviewed the need for TS 3.8.10, Distribution System – Shutdown, during movement of fuel assemblies in the fuel storage pool. Because the FHA analysis, and the other DBAs identified for SONGS Units 2 and 3, do not rely on the safety-related AC, DC and AC instrument bus electrical distribution systems for accident mitigation (including any need for providing airborne radiological protection), these safety-related distributions systems are not required during movement of fuel assemblies in the fuel storage pool for mitigation of a potential FHA or any of the other DBAs. Specifically, the accident analyses show that the dose consequences are acceptable without relying on any SSCs to remain functional during and following the postulated events, with the exception of the SFP support structure. Therefore, during movement of fuel assemblies in the fuel storage pool, there are no systems that function or actuate and are credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the DBA. As such, the requirement for safety-related AC, DC and AC instrument bus electrical distribution systems is no longer necessary because there are no design-basis events that rely on safety-related AC, DC and AC instrument bus electrical distribution systems for mitigation. Consequently, AC, DC and AC instrument bus electrical distribution systems no longer meet the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C) and can be removed from TSs. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 3.8.10, during movement of fuel assemblies in the fuel storage pool, is acceptable.

3.7.15 Section 3.9, Refueling Operations

Section 3.9 of the SONGS Units 2 and 3 TSs, "Refueling Operations," contains the LCOs, Actions, and SRs related to refueling operations. This section contains the following LCOs:

TS 3.9.1, "Boron Concentration," places limits on the boron concentrations of the RCS and the refueling canal to ensure that the reactor remains subcritical during refueling. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes, which have direct access to the reactor core during refueling. The boron concentration limits required by TS LCO 3.9.1 are specified in the COLR. The boron concentration limit specified in the COLR will maintain a k_{eff} of < 0.95 during fuel handling operations with CEAs and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by unit procedures. TS 3.9.1 is applicable in MODE 6.

TS 3.9.2, "Nuclear Instrumentation," requires that two source range monitors (SRMs) to be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. The SRMs are required to provide a signal to alert the operator to unexpected changes in core reactivity such as by a boron dilution event or an improperly loaded fuel assembly. TS 3.9.2 is applicable in MODE 6.

TS 3.9.3, "Containment Penetrations," specifies the requirements for containment closure during the conduct of CORE ALTERATIONS and movement of fuel assemblies within containment. The containment penetrations included within TS 3.9.3 are the equipment hatch, personnel airlock doors, and penetrations that provide direct access from the containment atmosphere to the outside atmosphere. TS 3.9.3 limits the consequences of an FHA involving handling fuel within containment by limiting the potential escape paths for fission product radioactivity released within containment. TS 3.9.3 is applicable during CORE ALTERATIONS and during the movement of fuel assemblies within containment.

TS 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," specifies requirements for the SDC system in MODE 6 to remove decay heat and sensible heat from the RCS, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification. One loop of the SDC system is required to be OPERABLE and in operation in MODE 6, with the water level > 20 feet above the top of the reactor vessel flange. Only one SDC loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. TS 3.9.4 is applicable in MODE 6, with the water level > 20 feet above the top of the reactor vessel flange.

TS 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level," also specifies requirements for the SDC system in MODE 6 to remove decay heat and sensible heat from the RCS, to provide mixing of borated coolant, to provide sufficient coolant circulation to minimize the effects of a boron dilution accident, and to prevent boron stratification. However, with the water level < 20 feet above the top of the reactor vessel flange, both SDC loops must be OPERABLE. Additionally, one loop of SDC must be in operation. TS 3.9.5 is applicable in MODE 6 with the water level < 20 feet above the top of the reactor vessel flange.

TS 3.9.6, "Refueling Water Level," specifies a minimum water level of 23 feet above the top of the reactor vessel flange during movement of fuel assemblies or CEAs within the reactor pressure vessel, and during movement of fuel assemblies within containment. A minimum refueling cavity water level of 23 feet above the top of the reactor vessel flange is required to ensure that the radiological consequences of a postulated FHA inside containment are within acceptable limits. The requirements of TS LCO 3.9.6, in conjunction with a minimum decay time of 72 hours prior to fuel movement, ensures that the release of fission product radioactivity, subsequent to an FHA, results in doses that are well within the guideline values specified in Regulatory Guide 1.183. TS 3.9.6 is only applicable during movement of fuel assemblies or CEAs within the reactor pressure vessel, and during movement of fuel assemblies within containment.

The licensee proposed to delete Section 3.9 of the SONGS Units 2 and 3 TSs LCOs, since they are only applicable to an operating reactor and do not apply to the permanently shutdown and defueled condition of SONGS Units 2 and 3.

The NRC staff has reviewed the proposed changes and has determined that Section 3.9 TSs are only needed to provide the LCOs and SRs necessary to maintain functionality of plant systems required for refueling operations. These TSs involve: boron concentration, which places limits on the boron concentrations of the RCS and the fuel transfer canal during refueling; nuclear instrumentation, which monitors the core reactivity condition during refueling operations; containment penetrations, which specifies requirements for containment closure during the conduct of refueling operations; residual heat removal and coolant circulation – high and low water level, which removes decay heat and sensible heat from the RCS, provides mixing of borated coolant, and prevents boron stratification; and refueling cavity water level, which specifies a minimum water level of 23 feet above the top of the reactor vessel flange during movement of irradiated fuel assemblies within containment. However, 10 CFR 50.82(a)(2) prohibits the licensee from operating the plant or placing fuel in the reactor vessel. Therefore, refueling operations are no longer permitted at SONGS Units 2 and 3, and the LCOs in Section 3.9 TSs are no longer relevant.

The NRC staff has also reviewed the refueling operations TSs proposed for deletion to ensure that these LCOs were no longer required to satisfy the 10 CFR 50.36 criteria for inclusion in TSs, as described in Section 2.1 of this evaluation. The NRC staff notes that these TSs indicate MODES for which each TS is applicable. MODES, as defined in TSs, correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning with fuel in the reactor vessel. The reference to MODES for a permanently shutdown and defueled reactor has no meaning and is not relevant. Because SCE has submitted certifications pursuant to 10 CFR 50.82(a)(2), it is prohibited from operating the reactor or placing fuel in the reactor vessel and SONGS Units 2 and 3 are no longer in a configuration or a condition under which the TS MODES apply.

Based on the above, the NRC staff finds that the licensee's proposed change to delete TS Section 3.9, Refueling Operations, is acceptable.

3.7.16 Section 4.0, Design Features

TS 4.1, "Site" provides a description regarding the location of SONGS. The licensee has proposed to retain this TS section in the permanently defueled SONGS Units 2 and 3 TSs with no changes.

TS 4.2, "Reactor Core," provides a general description of the number of and design material requirements for the fuel and control element assemblies used in the reactor core. The licensee has proposed to delete the design feature descriptions for fuel and control element assemblies, since they are only applicable to an operating reactor and do not apply to the permanently shutdown and defueled condition of SONGS Units 2 and 3.

The NRC staff has reviewed the proposed changes to delete the reactor core fuel and control element assemblies design features from SONGS Units 2 and 3 TSs. Since 10 CFR 50.82(a)(2) prohibits the licensee from operating the reactors or placing fuel in the reactor vessels, the design features related to the reactor core fuel assemblies and control rods are no longer relevant at SONGS Units 2 and 3. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 4.2, reactor core design features, is acceptable.

TS 4.3, "Fuel Storage," provides a description and the requirements regarding prevention of criticality of spent fuel, prevention of SFP drainage and spent fuel capacity limitations. This TS section is being retained in the permanently defueled TSs, with the exception of TS 4.3.1.2, which is the design and maintenance of the new fuel storage racks as discussed below. The licensee has also made editorial changes to the TS references in this section to conform to the proposed renumbering of certain retained TSs.

TS 4.3.1.2 has been proposed to be deleted because new fuel is no longer stored onsite and License Condition 2.B.(3) is being revised to no longer allow receipt of new fuel. The NRC staff has reviewed the proposed changes to remove the new fuel storage rack design features from the TSs. Since the licensee currently has no new fuel stored onsite and since the facility license will no longer allow new fuel to be stored onsite, the requirements for new fuel storage racks are no longer applicable.

Based on the above, the NRC staff finds the proposed changes to delete the new fuel storage rack design features from SONGS Units 2 and 3 TS 4.3.1.2 to be acceptable. The staff also reviewed the proposed renumbering of references in TS 4.3.1, Criticality, and determined that the changes to be conforming and editorial in nature. Therefore, the NRC staff finds that the licensee's proposed changes to TS 4.3, Fuel Storage, is acceptable.

3.7.17 Section 5.2, Organization and Section 5.3, Facility Staff Qualifications

SONGS Units 2 and 3 permanently defueled TS 5.1, "Responsibility"; TS 5.2, "Organization"; and TS 5.3, "Facility Staff Qualifications," were previously approved by the NRC staff in License Amendment Nos. 227 and 220 for SONGS Units 2 and 3, respectively, dated September 30, 2014 (ADAMS Accession No. ML14183B240).

The licensee has proposed several additional changes to TS 5.2, Organization, and TS 5.3, Facility Staff Qualification that were not included in Amendment Nos. 227 and 220. The first change is to capitalize the position of CERTIFIED FUEL HANDLER, consistent with its use as a defined term in TS 1.0, Definitions.

The NRC staff reviewed the proposed change to capitalize the position of CERTIFIED FUEL HANDLER where it is used in TS 5.2 and TS 5.3 and concludes the change is editorial in nature such that the current intent of the affected TS requirements is unchanged. Therefore, the staff finds that the licensee's proposed change to capitalize CERTIFIED FUEL HANDLER in TS 5.2 and TS 5.3, is acceptable.

The licensee has also proposed a change to Facility Staff TS 5.2.2.c (note that this was originally TS 5.2.2.b but was renumbered to TS 5.2.2.c by Amendment Nos. 227 and 220), to clarify that during unexpected absences of on-duty shift crew members, no fuel movement or movement of heavy loads over storage racks containing fuel is permitted. Specifically;

Facility Staff TS 5.2.2.c currently states:

> c. Shift crew composition may be less than the minimum requirement of Table 5.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

Revised Facility Staff TS 5.2.2.c would state:

> c. Shift crew composition may be less than the minimum requirement of Table 5.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements. During such absences, no fuel movement or movement of heavy loads over storage racks containing fuel is permitted.

The NRC staff has reviewed the proposed revision to TS 5.2.2.c restricting fuel movement or movement of heavy loads over storage racks containing fuel when an unexpected absence of the on-duty shift crew results in a minimum crew composition less than specified in TSs. The staff finds that additional restriction on fuel movement and heavy loads prudent considering the reduced staffing levels at a permanently shutdown and defueled reactor facility. Therefore, the NRC staff finds that the proposed licensee change to TS 5.2.2.c, is acceptable.

The licensee has also proposed a change to Facility Staff Qualifications TS 5.3.1 to delete the qualification requirements for multi-discipline supervisors. SCE states that it will no longer be utilizing the position of multi-discipline supervisor. Specifically;

Facility Staff Qualifications TS 5.3.1 currently states:

5.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except a) the radiation protection manager, who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, and b) multi-discipline supervisors who shall meet or exceed the qualifications listed below.

a. Education: Minimum of a high school diploma or equivalent.

b. Experience: Minimum of four years of related technical experience which shall include three years power plant experience of which one year is at a nuclear plant.

c. Training: Complete the multi-discipline supervisor training program.

Revised Facility Staff Qualifications TS 5.3.1 would state:

5.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except a) the radiation protection manager, who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

The NRC Staff has reviewed the proposed deletion of the qualifications for multi-discipline supervisors from the SONGS Units 2 and 3 TSs and concluded that the qualifications are not necessary since the licensee no longer utilizes multi-discipline supervisors. Therefore, the NRC staff finds that the licensee's proposed change to TS 5.3.1, is acceptable.

3.7.17.1 Section 5.4, Technical Specification (TS) Bases Control

SONGS Units 2 and 3, TS 5.4, "Technical Specifications (TS) Bases Control," is a program that provides the requirements for changing the TS Bases without prior NRC approval. TS 5.4 will remain applicable with the reactor permanently shutdown and defueled. As such, it is being retained and revised, as follows, to reflect a permanently defueled condition.

Currently, the licensee is required to submit changes to the TS Bases to the NRC, which have been implemented without prior NRC approval, within 6 months following every Unit 3 refueling, not to exceed 24 months. The licensee has proposed to revise TS 5.4.4 to be consistent with the submittal of UFSAR updates for the permanently shutdown and defueled status of SONGS Units 2 and 3. The TS Bases changes (that do not require NRC approval) will be submitted to the NRC for information and/or review every 24 months consistent with the UFSAR updates.

The NRC staff has reviewed the proposed change to TS 5.4.4 that aligns the submittal of changes to the TS Bases to every 24 months consistent with the submittal of the UFSAR changes. The NRC staff has determined that the proposed revision to the frequency of submitting the TS Bases Control changes to NRC is administrative in nature. The revised TS

5.4.4 continues to meet the minimum frequency of the original TS. In addition, the change is consistent with the requirements of 10 CFR 50.71(e) for providing UFSAR updates to the NRC for a permanently shutdown and defueled reactor (i.e., every 24 months). Therefore, the NRC staff finds that the licensee's proposed change to TS 5.4.4, is acceptable.

3.7.17.2 Section 5.5.1, Procedures

TS 5.5.1, "Procedures," addresses procedures, programs and manuals required by the SONGS Units 2 and 3 TSs. The licensee proposes to delete that following procedures from the permanently defueled technical specifications:

TS 5.5.1.1, "Scope," requires that written procedures be established, implemented, and maintained covering certain activities. The licensee has proposed to delete TS 5.5.1.1, paragraphs b and f.

TS 5.5.1.1, paragraph b., currently states:

> The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980 (ADAMS Accession No. ML051400209), and NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability," January 1983 (ADAMS Accession No. ML102560009), as stated in Generic Letter 82-33, "Supplement 1 to NUREG-0737 - Emergency Response Capabilities," dated December 17, 1982 (ADAMS Accession No. ML031080548), incorporated into one document all Three Mile Island (TMI)-related items approved for implementation by the Commission at that time. This included the use of human factored, function oriented, emergency operating procedures to improve human reliability and the ability to mitigate the consequences of a broad range of initiating events for operating reactors, and subsequent multiple failures or operator errors, without the need to diagnose specific events.

The licensee has proposed to delete the requirement of TS 5.5.1.1.b. because the emergency operating procedures discussed therein only pertain to accidents and events resulting from reactor operation. The licensee stated that the referenced procedures are no longer required for a permanently shutdown and defueled reactor.

The NRC staff reviewed the proposed deletion of TS 5.5.1.1.b. and determined that NUREG-0737, as supplemented, implemented programmatic changes to the way reactor operators are trained, instrumentation information is presented, and procedures are structured, using human factors and a function oriented approach to address operating events and accidents. These accidents, and the associated emergency operating procedures to detect, respond to, and mitigate such accidents, concerned malfunctions of the reactor and its supporting systems are not relevant to a permanently shutdown and defueled reactor, which is

no longer authorized to operate or place fuel in the reactor vessel. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.1.1.b., is acceptable.

TS 5.5.1.1.f., concerns the modification of the core protection calculator (CPC) addressable constants. Software modifications to constants, algorithms, or fuel cycle specific data shall be performed in accordance with the most recent version of "CPC Protection Algorithm Software Change Procedure," (CEN-39(A)-P). The licensee has proposed to delete TS 5.5.1.1.f. because the CPC is no longer required. The CPCs are one of two systems that monitor core power distribution online and derive the LHR and DNBR parameters and associated RPS trips. The TSs that rely on the CPC are TS 3.3.1 RPS Instrumentation - Operating and TS 3.3.3 Control Element Assembly Calculators, and are only applicable in MODES 1 and 2.

The NRC staff has determined that the instrumentation-related TS 3.3.1 and TS 3.3.3 that reference the CPC, as discussed in the Section 3.7.9 of this SE, are no longer required based on the permanent shutdown and defueled condition of SONGS Units 2 and 3. The CPC is part of the RPS to protect the reactor core from damage. Since SONGS Units 2 and 3 are not authorized to operate or emplace fuel in the reactor vessel, protection of the reactor core is no longer relevant, and a control procedure for the modification of the CPC, as required in TS 5.5.1.1.f., is unnecessary. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.1.1.f., is acceptable.

3.7.17.3 Section 5.5.2, Programs and Manuals

TS 5.5.2.4, "Component Cyclic or Transient Limit Program," controls to track cyclic and transient occurrences to ensure that RCS components are monitored for fatigue evaluation based on a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from normal operation, normal and abnormal load transients and accident conditions. The licensee proposes to delete this program since the RCS components monitored by this program are no longer used at SONGS Units 2 and 3 considering its permanently shutdown and defueled status.

The NRC staff has determined that deletion of the Component Cyclic or Transient Limit Program from TSs is consistent with the transition to a permanently shutdown and defueled facility. Since, in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the plant or placing fuel in the reactor vessel, the RCS and reactor support systems are no longer in use. Consequently, the component cyclic or transient limit program is not relevant at SONGS Units 2 and 3 since the components monitored by the program are permanently out of service. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.4, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.5, "Reactor Coolant Pump Flywheel Inspection Program," provides for the inspection of the reactor coolant pump flywheels. The licensee proposed to delete this program since the reactor coolant pump flywheel is a component only used in support of reactor operation. Inspection of the reactor coolant pump flywheel is not relevant to SONGS Units 2 and 3 since the licensee is no longer authorized to operate the reactor or emplace fuel in the reactor vessel.

The NRC staff has determined that deletion of the Reactor Coolant Pump Flywheel Inspection Program from TSs is consistent with the transition to a permanently shutdown and defueled facility. Since, in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the plant or placing fuel in the reactor vessel, reactor coolant pumps are no longer used in support of any function at the facility. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.5, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.6, "Secondary Water Chemistry Program," provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The licensee proposed to delete this program because the components that the program was established to protect, using water chemistry control, are associated with reactor operation. With the licensee's decision to cease reactor operations, these components are no longer in operation and do not need protection from degradation or stress corrosion cracking.

The NRC staff has determined that the deletion of the Secondary Water Chemistry Program is consistent with the transition to a permanently shutdown and defueled facility. Since, in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the plant or placing fuel in the reactor vessel, the SGs and turbine are no longer used in support of any function at the facility. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.6, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.7, "Explosive Gas and Storage Tank Radioactivity Monitoring Program," provides controls for potentially explosive gas mixtures in the gaseous radwaste system, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The licensee has proposed to revise the explosive gas and storage tank radioactivity monitoring program to be consistent with the permanently shutdown and defueled condition of the SONGS Units 2 and 3 facility. Paragraphs a. and b. of the program are being deleted because these portions of the explosive gas and storage tank radioactivity monitoring program pertain only to reactor support systems that are no longer needed due to SONGS permanently shutdown and defueled condition. Specifically, there will no longer be any source of explosive or radioactive gases generated from reactor operation. In addition, the licensee states that the gaseous radwaste system and the waste gas decay tank have been vented and removed from service. As such, references to potentially explosive gas mixtures and methods for determining gaseous radioactivity have been deleted. The licensee has proposed to retain the storage tank radioactivity monitoring program as modified below:

TS 5.5.2.7 <u>Storage Tank Radioactivity Monitoring Program</u>

This program provides controls for the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The liquid radwaste quantities shall be determined in accordance with the

> Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures."
>
> The program shall include a surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and do not have tank overflows and surrounding area drains connected to the Liquid Waste Management System is less than the amount that would result in concentrations less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.
>
> The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Storage Tank Radioactivity Monitoring Program surveillance frequencies.

The NRC staff has reviewed the proposed revision to the Storage Tank Radioactivity Monitoring Program. The staff finds the proposed changes prudent given the uncertainty in how future radwaste generated by flushing and cutting of radioactive systems will be stored and processed. Therefore, the NRC staff finds that the licensee's proposed change to TS 5.5.2.7, Storage Tank Radioactivity Monitoring Program, is acceptable.

TS 5.5.2.8, "Primary Coolant Sources Outside Containment Program," was established to minimize leakage from portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident. The licensee proposed to delete this program since primary coolant systems have been drained at SONGS Units 2 and 3 and there are no longer any transient or accident conditions associated with primary coolant sources given the permanently shutdown and defueled condition of the plant.

The NRC staff has determined that deletion of TS 5.5.2.8, "Primary Coolant Sources Outside Containment Program," is consistent with the transition to a permanently shutdown and defueled facility. Since the licensee has certified its permanent cessation of operations and defueling in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the reactors or placing fuel in the reactor vessels. Consequently, there are no DBAs involving reactor operation or refueling and there can no longer be any transients or accidents involving primary coolant outside of containment. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.8, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.9, "Pre-Stressed Concrete Containment Tendon Surveillance Program," provides controls for monitoring any tendon degradation in the pre-stressed concrete containment. The licensee has proposed to delete this program because the status of the containment is not relevant to the permanently shutdown and defueled reactors at SONGS Units 2 and 3.

The NRC staff considers that TS 5.5.2.9, "Pre-Stressed Concrete Containment Tendon Surveillance Program," is only applicable to a reactor authorized to operate or retain irradiated fuel in the reactor vessel. Pursuant to the licensee's certifications under 10 CFR 50.82(a)(2), the license is prohibited from operating the reactors or placing fuel in the reactor vessels at SONGS Units 2 and 3. Consequently, there are no DBAs involving reactor operation or refueling and no reliance on the containment to mitigate operating reactor DBAs. Thus, the staff has determined that containment tendon surveillance program TS is no longer applicable. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.9, is acceptable.

TS 5.5.2.10, "Inservice Inspection and Testing Program," establishes the controls for periodic inspection and testing of the American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3 pumps and valves in accordance with the ASME Operation and Maintenance Code. These code classes protect equipment relied upon to prevent and mitigate DBAs. The licensee proposed to delete this program since there is no longer any ASME Code Class 1, 2 or 3 pumps and valves, or Code Class CC or MC components in the SONGS Units 2 and 3 inservice inspection and testing program that continue to operate and perform a specific function in mitigating the consequences of a reactor accident due to the permanently shutdown and defueled status of the plants.

Because the licensee is prohibited from operating the plant or placing fuel in the reactor vessel, in accordance with 10 CFR 50.82(a)(2), there are no longer any ASME Code class pumps and valves that remain in operation and are to be relied upon to mitigate a DBA. As such, the inservice inspection and testing program is no longer relevant to SONGS Units 2 and 3, given the permanently shutdown and defueled status of these facilities. The NRC staff also notes that the licensee shall continue to monitor the performance and condition of all SSCs associated with the storage, control, or maintenance of spent fuel in in a safe condition and with reasonable assurance that these SSCs are capable of fulfilling their intended functions, pursuant to 10 CFR 50.65, ""Requirements for monitoring the effectiveness of maintenance at nuclear power plants." Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.10, Inservice Inspection and Testing Program, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.11, "Steam Generator (SG) Program," ensures that the SG tube integrity is maintained. The licensee proposed to delete this program since SONGS Units 2 and 3 are permanently defueled and not authorized to operate; therefore, the SGs are no longer functional and the SG tubes will not be subjected to the temperature and pressure effects that the SG program was put in place to protect against.

The NRC staff has determined that the SG program is only relevant to an operating reactor where the SGs are used for removing heat associated with reactor operation. Since the licensee has certified its permanent cessation of operations and defueling in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the reactors or placing fuel in the reactor vessels. Consequently, the SGs are no longer used in support of any function at the facility. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.11, appropriately reflects the change in plant status, and is acceptable.

TS 5.5.2.12, "Ventilation Filter Testing Program (VFTP)," establishes the required testing and frequency of the CREACUS high efficiency particulate filters and charcoal adsorbers utilized by the system.

The VFTP is being deleted because it pertains only to reactor support systems that does not apply in a permanently defueled condition. As noted, in part, by the licensee in its license amendment request, dated March 21, 2014, "[t]he accident analysis applicable to the permanently defueled condition does not rely on ventilation filters for accident mitigation."

The NRC staff has determined that reference to the VFTP only appears in SONGS Units 2 and 3 TSs in three places: TS 5.5.2.12; TS 3.7.11 "Control Room Emergency Air Cleanup System (CREACUS)" (SR 3.7.11.2 and SR 3.7.11.4); and TS 5.5.2.16.d of the "Control Room Envelope Habitability Program." The VFTP is used to confirm the function and operability of the CREACUS. The NRC staff has evaluated CREACUS in Section 3.7.13 (TS 3.7.11) and found that CREACUS is no longer required in the SONGS TSs per Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C). Since TS 5.5.2.12 "Ventilation Filter Testing Program" only exists to support the SRs of TS 3.7.11 (i.e. SR 3.7.11.2 and SR 3.7.11.4, respectively) and since the NRC approves that deletion of TS 3.7.11, the NRC staff finds the licensee's proposed change to delete TS 5.5.2.12, is acceptable.

TS 5.5.2.13, "Diesel Fuel Oil Testing Program," pertains to the testing of both new and stored fuel oil used to supply the EDGs. The accident analyses applicable to the permanently shutdown and defueled condition at SONGS no longer rely on EDGs for accident mitigation. The requirement for EDGs, which are supported by the fuel oil being tested per this program, has been proposed for deletion from the TSs.

The NRC staff has reviewed the proposed changes against the requirements in 10 CFR 50.36 and Chapter 15 of the SONGS UFSAR and concluded that the EDG fuel oil and lube oil system are not required. These support systems to the EDGs are not required because there are no active systems or associated support systems credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the FHA DBA. The staff confirmed that there are no other DBAs that rely on EDGs or the EDG support systems. In addition, the NRC staff approves the deletion of TS 3.8.3, "Diesel Fuel Oil, Lube Oil, and Starting Air," in Section 3.7.14 of this SE. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.13, the diesel fuel oil testing program, is acceptable.

TS 5.5.2.15, "Containment Leakage Rate Testing Program," is being proposed for deletion because the containment leakage rate testing program pertains only to verifying the operability of the containment systems. The need for containment or the associated required TSs does not apply in a permanently shutdown and defueled condition. The requirements for containment systems (i.e. TS 3.6.1, TS 3.6.2, TS 3.6.3, TS 3.6.4, TS 3.6.5, TS 3.6.6.1, TS 3.6.6.2, TS 3.6.8 and TS 3.9.3) are being deleted, as described in Section 3.7.12 of this SE.

Primary containment integrity and isolation are only required for post-accident conditions from power operations. However, 10 CFR 50.82(a)(2) prohibits the licensee from operating the plant

or placing fuel in the reactor vessel. Therefore TS 3.6.1, TS 3.6.2, TS 3.6.3, TS 3.6.4, TS 3.6.5, TS 3.6.6.1, TS 3.6.6.2, TS 3.6.8 and TS 3.9.3, which address primary containment integrity and isolation during power operations and refueling operations, are no longer applicable. The program specified TS 5.5.2.15 requires the implementation of containment leakage rate testing in accordance with 10 CFR Part 50 Appendix J, Option B, "Performance-Based Requirements." The TS 5.5.2.15 program is no longer needed since 10 CFR 50.54(o) excludes permanently defueled units from the requirements of 10 CFR Part 50 Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors." Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.15, Containment Leakage Rate Testing Program, is acceptable.

TS 5.5.2.16, "Control Room Envelope Habitability Program," ensures that adequate radiation protection is provided to permit access and occupancy of the CRE under DBA conditions without personnel receiving radiations exposures above limits. The licensee has proposed this program for deletion because the CRE is not required for providing airborne radiological protection for the control room operators for the remaining DBAs at SONGS Units 2 and 3 based on the permanently shutdown and defueled status of the facility.

The NRC staff evaluated the remaining accident analyses at SONGS Units 2 and 3 and confirmed that no ESF system is credited in the mitigation of the CR, EAB, or LPZ dose consequences, as detailed in Sections 3.2 through 3.6 of this SE. This includes no credit for the FHIS, the fuel handling building PACU filtration system, the CRIS and the CREACUS. The evaluation of the DBAs applicable to the permanently shutdown and defueled facility demonstrate that the dose consequences within the CRE are acceptable without relying on SSCs remaining functional for accident mitigation, including FHAs. (The one exception to this is the continued function of the passive fuel storage pool structure, which will be maintained as a TS for SONGS.)

Reference to the "Control Room Envelope Habitability Program" only appears in the current SONGS Units 2 and 3 TSs in two places: TS 5.5.2.16, "Control Room Envelope Habitability Program" and TS 3.7.11, "Control Room Emergency Air Cleanup System (CREACUS)" (SR 3.7.11.4).

The NRC staff previously determined in its evaluation of TS 3.7.11, "CREACUS," Section 3.7.13 of this SE, that CREACUS no longer satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii)(C). Consequently, the NRC staff has approved the deletion of TS 3.7.11 for SONGS Units 2 and 3. Since the Control Room Envelope Habitability Program only exists to support a surveillance requirement of TS 3.7.11 (i.e. SR 3.7.11.4) and since TS 3.7.11 will be deleted, the NRC staff finds that the licensee's proposed change to delete TS 5.5.2.16, Control Room Envelope Habitability Program, is acceptable.

TS 5.5.2.17, "Battery Monitoring and Maintenance Program," provides controls for safety-related battery maintenance. The licensee proposes deletion of this program consistent with the deletion of the corresponding TS for DC electrical systems and associated batteries. The licensee states that the SONGS accident analyses do not rely on batteries for any accident mitigation.

The NRC staff has reviewed the proposed changes against the requirements in 10 CFR 50.36 and Chapter 15 of the SONGS UFSAR and concluded that the DC electrical distribution system batteries are not required. The support systems to the DC electrical distribution system, including the batteries, are not required because there are no active systems or associated support systems credited as part of the initial conditions of an analysis or as part of the primary success path for mitigation of the remaining DBAs at SONGS Units 2 and 3. In addition, the NRC staff has approved the deletion of TS 3.8.6, "Battery Parameters," in Section 3.7.14 of this SE. Therefore, the NRC staff finds that the licensee's proposed change to delete the TS 5.5.2.17, the battery monitoring and maintenance program, is acceptable.

3.7.17.4 Section 5.6, Safety Function Determination Program (SFDP)

The SONGS Units 2 and 3, "Safety Function Determination Program (SFDP)," as detailed in TS 5.6.1, TS 5.6.2, TS 5.6.3 and TS 5.6.4, ensures that a loss of safety function is detected and appropriate actions taken. Upon failure to meet two or more LCOs at the same time, an evaluation shall be made to determine if loss of safety function exists. The program implements the requirements of LCO 3.0.6. LCO 3.0.6 directs an evaluation in accordance with the SFDP to determine if a loss of safety function exists based on the status of redundant TS safety systems and associated support systems (systems that support the functionality of the safety system) to ensure the appropriate required actions are taken to maintain overall reactor safety. There are no active SSCs at SONGS Units 2 and 3 that are required for accident mitigation with the permanent cessation of reactor operations and the permanent removal of the fuel from the reactor vessels, as discussed in the evaluation of the remaining DBAs in Sections 3.2 through 3.6 of this SE. Therefore, the requirements of the SFDP, which directs cross-train checks of multiple and redundant safety systems, no longer apply.

Based on the permanently shutdown and defueled status of SONGS Units 2 and 3, all specifications for the active systems from the defueled TSs have been proposed for deletion by this licensing action. Consequently, the SFDP is no longer meaningful. In addition, the SFDP is invoked by LCO 3.0.6, which is being deleted in its entirety, as discussed in Section 3.7.6 of this SE. Therefore, the NRC staff finds that the licensee's proposed change to delete TS Section 5.6, Safety Function Determination Program, is acceptable.

3.7.17.5 Section 5.7, Reporting Requirements

TS 5.7.1.1, "Annual Reports," requires a Reactor Coolant System Specific Activity Report in accordance with TS 5.7.1.1.b. The report gathered data on reactor conditions when the I-131 or gross specific activity of the reactor coolant exceeded limits specified in TS 3.4.16. The licensee has proposed to delete SONGS Units 2 and 3, TS 5.7.1.1.b, "Reactor Coolant System Specific Activity Report," since it is not applicable to a permanently shutdown and defueled reactor.

The NRC staff has reviewed the proposed deletion of TS 5.7.1.1 concerning the Reactor Coolant Specific Activity Report. The facility RCSs have been drained and the activity of the RCS is no longer relevant to the SONGS Units 2 and 3 in their permanently shutdown and

defueled status. In addition, as noted above, TS 5.7.1.1.b only exists to analyze data related to the exceedance of limits specified in TS 3.4.16. Since RCS activity is not meaningful for SONGS and TS 3.4.16 will be deleted, the NRC staff finds that the licensee's proposed change to delete TS 5.7.1.1, is acceptable.

TS 5.7.1.2, "Annual Radiological Environmental Operating Report," covers summaries, interpretations, and analyses of trends related to the radiological environmental monitoring program, for each unit, during the previous calendar year.

The licensee has proposed to revise the TS description by replacing applicability of the report to the "facility" rather than to each 'unit." In addition, the licensee is deleting a Note indicating "a single submittal may be made for a multiple unit station." This note is no longer necessary since the SONGS facility is no longer treated as a multiunit site for the purposes of the annual radiological environmental operating report.

The NRC staff reviewed the proposed revision to TS 5.7.1.2 and concludes that changing the word "unit" to "facility" and the deletion of the multiple unit station note is a clarifying change that is editorial in nature such that the current intent of the requirement is unchanged. Therefore, the NRC staff finds that the licensee's proposed change to TS 5.7.1.2, Annual Radiological Environmental Operating Report, is acceptable.

TS 5.7.1.3, "Radioactive Effluent Release Report," covers "...the operation of the unit during the previous calendar year...." In addition, the report shall summarize the "...effluents released from the unit," and "... radioactive waste shipped from the unit directly..." and "... radioactive waste shipped from the unit's intermediary processor..."

The licensee proposed to revise the TS description by replacing "unit" with "facility" such that the description will state "... the operation of the facility during the previous calendar year ..." and, effluents "... released from the facility" and "... radioactive waste shipped from the facility directly ..." and "... radioactive waste shipped from the facility's intermediary processor...." In addition, the licensee is deleting a Note indicating "a single submittal may be made for a multiple unit station." This note is no longer necessary since the SONGS facility is no longer treated as a multiunit site for the purposes of the radioactive effluent release report.

The NRC staff reviewed the proposed revision to TS 5.7.1.3 and concludes that changing the word "unit" to facility" and the deletion of the multiple unit station note is a clarifying change that is editorial in nature such that the current intent of the requirement is unchanged. Therefore, the NRC staff finds that the licensee's proposed change to TS 5.7.1.3, Radioactive Effluent Release Report, is acceptable.

TS 5.7.1.5, "Core Operating Limits Report (COLR)," establishes the core operating limits prior to each reload cycle. The licensee proposed to delete this program since it is prohibited from reloading fuel into the SONGS Units 2 and 3 reactor core and the safety limits established by this report no longer apply.

The NRC staff has determined that the proposed deletion of the COLR would appropriately reflect the permanently shutdown and defueled condition of the facility. The COLR only applies to reactors authorized to operate. Since the licensee is prohibited from operating the SONGS reactors or placing fuel in the reactor vessels, the COLR is no longer necessary. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.7.1.5, is acceptable.

TS 5.7.1.6, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)," documents the pressure and temperature limits for heatup, cooldown, heatup and cooldown rates, low temperature operation, criticality, and hydrostatic testing as referenced in the following TSs:

- TS 3.4.3 RCS Pressure and Temperature (P/T) Limits
- TS 3.4.6 RCS Loops – Mode 4
- TS 3.4.7 RCS Loops – Mode 5, Loops Filled
- TS 3.4.12.1 Low Temperature Overpressure Protection (LTOP) System, RCS Temperature≤PTLR Limit
- TS 3.4.12.2 Low Temperature Overpressure Protection (LTOP) System, RCS Temperature>PTLR Limit

The licensee proposes to delete this program since the RCS is no longer used at SONGS Units 2 and 3 in its permanently shutdown and defueled status.

The NRC staff has determined that deletion of the Reactor Coolant System Pressure and Temperature Limits Report from TSs is consistent with the transition to a permanently shutdown and defueled facility. Since, in accordance with 10 CFR 50.82(a)(2), the licensee is prohibited from operating the reactors or placing fuel in the reactor vessels, the RCS and reactor support systems are no longer in use. Consequently, the RCS PTLR is not relevant at SONGS Units 2 and 3 since the RCS is no longer functional. The staff notes that the change is consistent with the deletion of the Section 3.4 RCS TSs that reference the PTLR as discussed in Section 3.7.10 of this SE. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.7.1.6, appropriately reflects the change in the SONGS plant status, and is acceptable.

TS 5.7.1.7, "Hazardous Cargo Traffic Report," requires that SCE monitors the hazardous cargo traffic on Interstate Highway 5 and the railroad line near SONGS and submits the results to the NRC Regional Administrator once every 3 years. This reporting requirement addressed potential changes in use characteristics of these transportation routes over the life of the facility. In the enclosure to the license amendment request dated March 21, 2014, SCE proposed to delete this reporting requirement from the TSs. In the supplement dated February 23, 2015, SCE stated that it would continue to perform the hazardous traffic report in accordance with a licensee-controlled documents.

The requirements of 10 CFR 50.36(c)(5) state that Administrative Controls TSs should include reporting necessary to assure operation of the facility in a safe manner. The reporting requirements included in Section 5.6 of NUREG-1432, "Standard Technical Specifications – Combustion Engineering Plants," Volume 1 (ADAMS Accession No. ML12102A165), include only those reports specified in the LCOs and those required by regulation. The Hazardous

Cargo Traffic Report does not directly relate to operation of the facility in a safe manner. Rather, it helps identify changes in the site environs that should be periodically assessed to ensure that the scope of events considered in the design-basis remains adequate. Consequently, the report does not significantly contribute to assuring operation in a safe manner. Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.7.1.7, Hazardous Cargo Traffic Report, and implement a similar reporting requirement in a licensee controlled document, is acceptable.

TS 5.7.2, "Special Reports," provides a description and requirements regarding reports related to inspections, tests, and maintenance activities as directed in other SONGS TSs. The listed Special Reports pertain to 1) a pre-planned alternate method of monitoring post-accident instrumentation functions, 2) abnormal degradation of the containment structure detected during tests required by the Pre-Stressed Concrete Containment Tendon Surveillance Program, and 3) a report, following entry into MODE 4, concerning inspections performed in accordance with the SG program. The licensee states that these reports are being deleted because they do not apply in a permanently defueled condition.

The NRC staff concludes that the TS required special report information on inspections, tests, and maintenance activities for safety-related instrumentation, containment, and SGs, apply to SSCs that are no longer relevant at a permanently shutdown and defueled SONGS reactors. In addition, the NRC has approved the deletion of the associated TSs for the SSC that are subject to these special reports from the SONGS Unit 2 and 3 permanently defueled TSs. Specifically:

(1) the special report for a pre-planned alternate method of monitoring post-accident instrumentation functions is no longer necessary since the post-accident monitoring instrumentation in TS 3.3.11 is being deleted from the SONGS defueled TSs, as discussed in Section 3.7.9 of this SE.

(2) the special report on abnormal degradation of the containment structure detected during tests required by the Pre-Stressed Concrete Containment Tendon Surveillance Program is no longer necessary since the tendon surveillance program in TS 5.5.2.9 is being deleted from the SONGS defueled TSs, as discussed in Section 3.7.17.3 of this SE.

(3) the special report, following entry into MODE 4, concerning inspections performed in accordance with the SG program is no longer necessary since the SG program in TS 5.5.2.11 is being deleted from the SONGS defueled TSs, as discussed in Section 3.7.17.3 of this SE.

Therefore, the NRC staff finds that the licensee's proposed change to delete TS 5.7.2, Special Reports, is acceptable.

3.8 Changes to Facility Operating License

In SCE's March 21, 2014, license amendment request, as supplemented by a letters dated February 25, 2015, and March 18, 2015, the licensee proposed to remove, modify, and add, several facility operating license conditions, based on the permanently shutdown and defueled status of SONGS Units 2 and 3.

3.8.1 Changes to License Condition 2.B.(2)

Currently License Condition 2.B.(2), for SONGS Units 2 and 3, reads:

> (2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess, use, and operate the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license.

The licensee is proposing to strike reference in the license condition to "...operate..." the facility.

The revised License Condition 2.B.(2) will read, as follows:

> (2) Southern California Edison Company (SCE), pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," to possess and use the facility at the designated location in San Diego County, California, in accordance with the procedures and limitations set forth in this license.

Pursuant to 10 CFR 50.82(a)(2), as a result of the 10 CFR 50.82(a)(1)(i) and 10 CFR 50.82(a)(1)(ii) certifications submitted by the licensee, the 10 CFR Part 50 licenses for SONGS Units 2 and 3 no longer authorize operation of the reactors. As such, reference to operation of the facility in License Condition 2.B.(2) is inconsistent with the limitation imposed on the licensee by 10 CFR 50.82(a)(2). Therefore, the NRC staff finds the licensee's proposed change to License Condition 2.B.(2) provides consistency with 10 CFR 50.82(a)(2) and, is acceptable.

3.8.2 Changes to License Condition 2.B.(3)

Currently License Condition 2.B.(3), for SONGS Units 2 and 3, reads:

> (3) SCE, pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

The licensee is proposing to revise this license condition to read, as follows:

> (3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

The licensee states the proposed revision to this license condition is consistent with the restrictions of 10 CFR 50.82(a)(2) that no longer authorizes operation or emplacement of fuel in the reactor vessels at SONGS Units 2 and 3.

The proposed change removes the authorization for receipt and use of special nuclear material (SNM) as reactor fuel and eliminates the reference to use of the SNM for reactor operations. The proposed change also limits the possession of SNM pursuant to the license condition as being "that was used" as reactor fuel. Pursuant to 10 CFR 50.82(a)(2) the 10 CFR Part 50 licenses for SONGS Units 2 and 3 no longer authorize operation of the reactors. As such, the licensee has no need to receive SNM in the form of reactor fuel and cannot use SNM as reactor fuel for reactor operations. The continued authorization to possess SNM "that was used" as reactor fuel is necessary as the licensee currently possesses the reactor fuel that was used for the past operations of the reactor. Based on the above, the NRC staff finds the licensee's proposed change to License Condition 2.B.(3) is consistent with the permanently shutdown status of SONGS Units 2 and 3 and is, therefore, acceptable.

3.8.3 Changes to License Condition 2.B.(4)

Currently License Condition 2.B.(4), for SONGS Units 2 and 3, reads:

> (4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

The licensee is proposing to revise this license condition to read, as follows:

> (4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

The licensee states the proposed revision to this license condition is consistent with the restrictions of 10 CFR 50.82(a)(2) that no longer authorizes operation or emplacement of fuel in the reactor vessels at SONGS Units 2 and 3. The proposed changes remove the authorization for receipt and use of byproduct, source, and SNM as sealed neutron sources for reactor startup but retains authorization to possess such sources previously used for reactor startup. The deletion of the authorization to receive and use sources for reactor startup is consistent with the fact that SONGS Units 2 and 3 are no longer authorized to operate and the continued authorization to possess neutron sources that were used for reactor startup is consistent with the safe storage of byproduct, source, and SNM. As such, the NRC staff finds that the licensee's proposed change to License Condition 2.B.(4), is consistent with the permanently shutdown status of the facilities and is, therefore, acceptable.

3.8.4 Changes to License Condition 2.C.(1)

Current License Condition 2.C.(1), for SONGS Units 2 and 3, reads:

> Maximum Power Level
>
> (1) Southern California Edison Company (SCE) is authorized to operate the facility at reactor core power levels not in excess of full power (3438 megawatts thermal).

The licensee is proposing to delete this license condition, which will read:

> (1) Deleted

The licensee states that this license condition can be deleted because SONGS Units 2 and 3 are permanently shut down and defueled in accordance with 10 CFR 50.82(a)(2) and therefore power operation is no longer authorized.

The NRC staff has reviewed the proposed deletion of License Condition 2.C.(1) and determined that power operation is no longer authorized at SONGS Units 2 and 3 based on the licensee's 10 CFR 50.82(a)(2) certifications of being permanently shutdown and defueled. The licensee is not authorized to operate the SONGS Units 2 and 3 at any power. Therefore, the NRC staff finds the licensee's proposed change to delete License Condition 2.C.(1) is appropriate and, is acceptable.

3.8.5 Changes to License Condition 2.C.(14) [Unit 2] and License Condition 2.C.(12) [Unit 3]

Current License Condition 2.C.(14) for SONGS Units 2 and License Condition 2.C.(12) for SONGS Unit 3, read:

> Fire Protection (Section 9.5.1, SER, SSER #4, SSER #5, Section 1.12, SSER #5; SE dated November 15, 1982; Revision 1 to Updated Fire Hazards Analysis Evaluation dated June 29, 1988)
>
> SCE shall implement and maintain in effect all provisions of the approved fire protection program. This program shall be (1) as described in the Updated Fire Hazards Analysis through Revision 3 as revised by letters to the NRC dated May 31, July 22. and November 20, 1987 and January 21, February 22, and April 21, 1988; and (2) as approved in the NRC staff's Safety Evaluation Report (SER) (NUREG-0712) dated February 1981; Supplements 4 and 5 to the SER, dated January 1982 and February 1982, respectively; and the safety evaluation dated November 15, 1982; as supplemented and amended by the Updated Fire Hazards Analysis Evaluation for San Onofre 2 and 3, Revision 1 dated June 29, 1988. SCE may make changes to the approved fire protection program without prior approval of the Commission

only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

The licensee is proposing to delete License Condition 2.C.(14) for SONGS Unit 2 and delete License Condition 2.C.(12) for SONGS Unit 3, which will read:

Unit 2

(14) Deleted

Unit 3

(12) Deleted

The licensee states that this license condition is based on maintaining an operational fire protection program in accordance with 10 CFR 50.48, "Fire protection," with the ability to achieve and maintain safe shutdown of the reactor in the event of a fire and is no longer applicable at SONGS Units 2 and 3. However, many of the elements that are applicable for the operating plant fire protection program continue to be applicable during plant decommissioning. During the decommissioning process, a fire protection program is required by 10 CFR 50.48(f) to address the potential for fires that could result in a radiological hazard. However, the regulation is applicable regardless of whether a requirement for a fire protection program is included in the facility license. Therefore, a license condition requiring such a program for a permanently shutdown and defueled plant is not needed.

The NRC staff finds that License Conditions 2.C.(14) and 2.C.(12), "Fire Protection," for SONGS Units 2 and 3, respectively, are based on maintaining fire protection programs that provides reasonable assurance that the ability to achieve and maintain safe shutdown in the event of a fire in accordance with 10 CFR 50.48. Achieving and maintaining safe shutdown in the event of a fire is no longer applicable to the decommissioned fire protection programs at SONGS Units 2 and 3, since units are permanently shutdown and the fuel has been removed from the reactors. However, elements of the fire protection program continue during decommissioning to address fire events that could result in radiological hazards. The regulation in 10 CFR 50.48(f) requires SONGS Units 2 and 3 to address the potential for fires, which could result in a radiological hazard. The licensee has proposed that the rule is sufficient to ensure that a program is maintained and therefore having a license condition that also requires fire protection programs for the permanently shutdown and defueled units is redundant. Basis on the evaluation above, the NRC staff concludes that reliance on 10 CFR 50.48(f) is appropriate and the fire protection license condition is no longer necessary. Therefore, the NRC staff finds that the licensee's proposed change to delete License Condition 2.C.(14) for SONGS Units 2, and License Condition 2.C.(12) for SONGS Unit 3, is acceptable.

3.8.6 Changes to License Condition 2.C.(27) [Unit 2] and License Condition 2.C.(28) [Unit 3]

Current License Condition 2.C.(27) for SONGS Unit 2, and License Condition 2.C.(28) for SONGS Unit 3, read:

> Upon implementation of Amendment No. 214 [Unit 2 and Amendment No. 206, Unit 3] adopting TSTF 448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 3.7.11.4 in accordance with TS 5.5.2.16.c(i), the assessment of CRE habitability as required by Specification 5.5.2.16.c(ii), and the measurement of CRE pressure as required by Specification 5.5.2.16.d, shall be considered met. Following implementation:
>
> (a) The first performance of SR 3.7.11.4, in accordance with Specification 5.5.2.16.c(i) shall be within the specified frequency of 6 years, plus the 18-month allowance of SR 3.0.2, as measured from May 18, 2004, the date of the most recent successful tracer gas test, as stated in the September 17, 2004 letter response to Generic Letter 2003-01, or within the next 18 months if the time period since the most recent successful tracer gas test is greater than 6 years.
>
> (b) The first performance of the periodic assessment of CRE habitability, Specification 5.5.2.16.c(ii), shall be within 3 years, plus the 9-month allowance of SR 3.0.2, as measured from May 18, 2004, the date of the most recent successful tracer gas test, as stated in the September 17, 2004, letter response to Generic Letter 2003-01, or within the next 9 month if the time period since the most recent successful tracer gas is greater than 3 years.
>
> (c) The first performance of the periodic measurement of CRE pressure, Specification 5.5.2.16.d, shall be within 6 months.

The licensee is proposing to delete License Condition 2.C.(27) for SONGS Unit 2 and License Condition 2.C.(28) for SONGS Unit 3, which will read:

> <u>Unit 2</u>
>
> (27) Deleted
>
> <u>Unit 3</u>
>
> (28) Deleted

The NRC staff evaluated the remaining accident analyses at SONGS Units 2 and 3 and confirmed that no ESF system is used to mitigate the CR, EAB, or LPZ dose consequences, as

detailed in Sections 3.2 through 3.6 of this SE. This includes no credit for the FHIS, the fuel handling building PACU filtration system, the CRIS and the CREACUS. Since SONGS Units 2 and 3 are permanently shut down and defueled, and greater than 17 months of decay time has elapsed since permanent shut down, the remaining DBAs applicable to the facility demonstrate that the dose consequences within the CRE are acceptable without relying on SSCs remaining functional for accident mitigation, with the exception of the passive fuel storage pool structure. In addition, the staff has determined that related CREACUS TS 3.7.11, and the Control Room Envelope Habitability Program TS 5.5.2.16, are no longer needed, as discussed in Sections 3.7.13 and 3.7.17.3, respectively, of this SE. Based on the discussion above, the NRC staff finds that the licensee's proposed change to delete of SONGS Unit 2 License Condition 2.C.(27), and SONGS Unit 3 License Condition 2.C.(28), is acceptable.

3.8.7 New License Condition 2.C.(28) [Unit 2] and License Condition 2.C.(29) [Unit 3]

By letter dated February 25, 2015 (ADAMS Accession No. ML15058A033), the licensee responded to an RAI from the NRC staff regarding the actions that will be taken by SCE to provide reasonable assurance that the passive, long-lived structures and components in the SFP, the fire protection system, and the radiation protection system, will be maintained in a safe condition beyond the normal licensed operating period of 40 years, pursuant to the provisions of 10 CFR 50.51(b). The NRC staff asked the licensee to identify and list the long-live, passive structures and components. In addition, the staff requested a summary of actions that will be taken to monitor and maintain the long-lived, passive structures and components. One of the staff's concerns involved the aging of neutron absorbing materials used for criticality control in SFPs.

SCE responded to the specific concern on the use of neutron absorbing materials in the SFP racks at SONGS. SCE noted that the SONGS SFP racks do contain Boraflex, a neutron-absorbing material. However, no credit is taken in SONGS accident analyses or licensing basis for the existence of the Boraflex. In addition, the NRC previously evaluated and approved borated stainless steel rods that may be placed in fuel assembly guide tubes (GTs) for reactivity control. This feature has not been implemented. If implemented in the future, SONGS will institute a surveillance program where, at 5-year intervals, 1 percent of the GT-Inserts will be inspected for any material degradation. The allowance for GT-Inserts and the commitment to the associated inspection program are described in Section 2.3.3.1.2.4.2 of the SE for Amendment Nos. 213 and 205 for SONGS Units 2 and 3, respectively (ADAMS Accession No. ML072550175).

The licensee stated that its current plans are to have all the spent fuel currently stored in the SFPs transferred to the dry cask storage ISFSI before the operating license for either SONGS Units 2 or 3 expires. However, SCE stated it will develop a list of long-lived, passive structures and components if unforeseen circumstances threaten to extend the period of fuel storage in the SFP beyond the current licensed period. SCE will develop the list and an associated aging-management program for those components if all of the spent fuel has not been removed from the SFP by February 16, 2021.

The expiration date of the Unit 2 operating license (that is, the end of the initial 40-year period of operation) is February 16, 2022. The expiration date of the Unit 3 operating license is November 15, 2022. All spent fuel onsite is expected to be moved to the ISFSI approximately 3 years prior to the expiration of the initial 40-year period of operation for both Units 2 and 3. Therefore, for the Units 2 and 3 SFPs, there is no anticipated need for long-lived, passive structures and components beyond the 40-year period of operation for Units 2 and 3, nor is there an anticipated need to monitor or maintain such structures and components beyond the licensed 40-year period of operation. Should the transition of fuel to the ISFSI be delayed by unforeseen events, it is possible that spent fuel could remain in the SFPs beyond the expiration of the 40-year operating period. Therefore, SCE proposed new license conditions for SONGS Units 2 and 3.

New License Condition 2.C.(28) for SONGS Unit 2, and License Condition 2.C.(29) for SONGS Unit 3, will read:

Unit 2

(28) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 2 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 2 until such time that all spent fuel has been removed from the Unit 2 spent fuel pool.

Unit 3

(29) Prior to February 16, 2021, if all spent fuel has not been removed from the Unit 3 spent fuel pool, an aging-management program shall be submitted for NRC approval. The scope of the program shall include those long-lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the spent fuel pool. Once approved, the program shall be described in the Updated Final Safety Analysis Report and shall remain in effect for Unit 3 until such time that all spent fuel has been removed from the Unit 3 spent fuel pool.

The NRC staff has evaluated the licensee's proposed response to the maintenance of long-lived passive structures and components considering the following applicable NRC regulations:

The regulation in 10 CFR Part 50, Appendix A, General Design Criteria (GDC) 62, "Prevention of criticality in fuel storage and handling," requires the prevention of criticality by physical systems or processes, preferably by use of geometrically safe configurations.

The regulations in 10 CFR 50.51(b) require licensees that have provided certifications for permanent cessation of power operations and permanent removal of fuel in accordance with 10 CFR 50.82(a)(1)(i) and 10 CFR 50.82(a)(1)(ii) to take actions necessary to decommission and decontaminate the facility and continue to maintain the facility in a safe condition.

The regulations in 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," require licensees to monitor performance or condition of SSCs to ensure they are capable of fulfilling their intended function. The scope of the monitoring specified in 10 CFR 50.65(a)(1) applies to safety-related SSCs as stated in 10 CFR 50.65(b)(1) and to nonsafety-related SSCs whose failure could prevent safety-related SSCs from fulfilling their intended function as stated in 10 CFR 50.65(b)(2)(ii).

The regulations in 10 CFR 50.68 specify requirements for the prevention of criticality accidents and mitigating the radiological consequences of a criticality accident.

The licensee has proposed aging management related license conditions for both SONGS Units 2 and 3, contingent that all remaining fuel will be removed from the SFP by February 16, 2021. If by this time the fuel is not removed from the SFP, the license condition will require that the licensee submit an aging management program for NRC approval. The scope of the program shall include those long lived, passive structures and components that are needed to provide reasonable assurance of the safe condition of the spent fuel in the SFP. Once approved, the program shall be described in the UFSAR and shall remain in effect until such time that all spent fuel has been removed from the SFP. The NRC staff notes that the proposed changes do not affect the design or use of the existing fuel racks, and therefore no criticality analysis was made in association with the changes. The proposed changes also keep intact the systems for the SFP needed to keep the fuel in a subcritical condition. The staff has reviewed the licensee's response to the staff's aging-management concerns and the proposed license conditions to address the concerns. Given that the licensee expects to have all fuel removed from the SONGS SFPs prior to the expiration of the original operating license, the NRC staff has concluded that the proposed new License Condition 2.C.(28) for SONGS Unit 2 and License Condition 2.C.(29) for SONGS Unit 3, adequately address the staff's concerns regarding the maintenance of passive, long-lived structures and components in a safe condition beyond the normal licensed operating period of 40 years, and therefore, finds that the new license conditions are acceptable.

3.8.8 Deletion of License Condition 2.J and Proposed New License Condition 3

Current License Condition 2.J, reads:

Unit 2

J. This license is effective as of the date of issuance and shall expire at midnight on February 16, 2022.

Unit 3

J. This license is effective as of the date of issuance and shall expire at midnight on November 15, 2022.

Revised License Condition 2.J would state for SONGS Units 2 and 3, will read:

J. Deleted

SCE stated that this license condition can be deleted because SONGS Units 2 and 3 have permanently ceased operation. 10 CFR 50.82(a)(2) prohibits operation of the SONGS Units 2 and 3 reactor since the certifications described therein have been docketed. SCE has proposed that this license condition be replaced by new License Condition 3, which conforms to 10 CFR 50.51, "Continuation of license," in that the license authorizes ownership and possession of SONGS Units 2 and 3 until the Commission notifies the licensee in writing that the license is terminated. The proposed new license condition for SONGS Units 2 and 3, to be used in place of License Condition 2.J., will be License Condition 3.

New License Condition 3 for SONGS Unit 2, will read:

3 On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 2 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On July 22, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 2 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

New License Condition 3 for SONGS Units 3, will read:

3. On June 12, 2013, Southern California Edison (SCE) certified that operations at San Onofre Nuclear Generating Station Unit 3 would permanently cease in accordance with 10 CFR 50.82(a)(1)(i). On June 28, 2013, SCE certified that the fuel had been permanently removed from the reactor vessel in accordance with 10 CFR 50.82(a)(1)(ii). As a result, the 10 CFR 50 license no longer authorizes operation of the reactor, or the emplacement or retention of fuel in the reactor vessel.

   This license is effective as of the date of issuance and authorizes ownership and possession of San Onofre Nuclear Generating Station Unit 3 until the Commission notifies the licensee in writing that the license is terminated. The licensee shall:

   A. Take actions necessary to decommission the plant and continue to maintain the facility, including, where applicable, the storage, control and maintenance of the spent fuel, in a safe condition; and

   B. Conduct activities in accordance with all other restrictions applicable to the facility in accordance with the NRC regulations and the applicable provisions of the 10 CFR 50 facility license as defined in Section 2 of this license.

The NRC staff has reviewed the proposed deletion of Licensee Condition 2.J and the proposed new License Condition 3 and determined that License Condition 2.J, which documented the date of the expiration of the license, is no longer meaningful for the permanently shutdown condition of the plant in the process of decommissioning. The proposed new License Condition 3 documents the current condition of the plant and summarizes the actions and requirements applicable to the facility by regulation. The proposed License Condition 3 is consistent with the regulatory requirements applicable to the facility in the permanently shutdown and defueled condition, and consistent with a previously issued license conditions for the permanently shutdown and defueled Millstone Unit 1 and the Kewaunee Power Station. Based on the above, the NRC staff finds that the proposed license condition changes are acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the California State official was notified on May 28, 2015, of the proposed issuance of the amendments. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding as published in the *Federal Register* on September 16, 2014 (79 FR 55513). The amendments also relates to changes in recordkeeping, reporting, or administrative procedures or requirements. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9) and 10 CFR 51.22(c)(10). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The NRC staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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Date: July 17, 2015

T. Palmisano

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Thomas J. Wengert, Senior Project Manager
Plant Licensing IV-2 and Decommissioning
Transition Branch
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-361 and 50-362

Enclosures:
1. Amendment No. 230 to NPF-10
2. Amendment No. 223 to NPF-15
3. Safety Evaluation

cc w/enclosures: Distribution via Listserv

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ADAMS Accession No.: ML15139A390 * see previous **concurrence via memo

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NAME	WHuffman*	PBlechman*	UShoop (by JDozier for)	RElliott* (by MChernoff for)	RDennig
DATE	5/21/15	7/13/15	02/13/15	4/2/15	9/30/14
OFFICE	NRR/DSS/SBPB/BC**	NRR/DSS/SRXB/BC**	NRR/DE/EEEB/BC**	NRR/DE/EICB/BC**	OGC/NLO
NAME	GCasto	CJackson	JZimmerman	JThorp	BMizuno*
DATE	3/16/15	3/27/15	6/1/15	2/27/15	7/14/15
OFFICE	NRR/DORL/LPL4-2/BC	NRR/DORL/LPL4-2/PM			
NAME	MKhanna	TWengert			
DATE	7/17/15	7/17/15			

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EXHIBIT 10

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November , 2017

Mr. Thomas J. Palmisano
Vice President and Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 - ISSUANCE OF AMENDMENTS TO REVISE THE PERMANENTLY DEFUELED EMERGENCY PLAN (CAC NOS. L53160, L53161, and L53162)

Dear Mr. Palmisano:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 168 to Facility Operating License No. DPR-13, Amendment No. 236 to Facility Operating License No. NPF-10, and Amendment No. 229 to Facility Operating License No. NPF-15 for the San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, respectively. The amendments consist of changes to the Permanently Defueled Emergency Plan (PDEP) in response to your application dated December 15, 2016 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML16355A015), as supplemented by letter dated May 5, 2017 (ADAMS Accession No. ML17160A324). The proposed changes more fully reflect the status of the facility, as well as the reduced scope of potential radiological accidents once all spent fuel has been moved to dry cask storage within the onsite independent spent fuel storage installation (ISFSI), an activity which is currently scheduled for completion in 2019.

The proposed changes replace the SONGS PDEP and associated Emergency Action Level (EAL) Bases Manual (hereafter referred to as the EAL scheme) with an ISFSI-Only Emergency Plan (IOEP) and associated EAL scheme. The NRC staff determined that the proposed SONGS IOEP and associated EAL changes continue to meet the standards in Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.47, “Emergency plans,” and the requirements in Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” of 10 CFR Part 50, as exempted. As such, the SONGS IOEP and associated EAL changes provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency.

The NRC staff has determined that its documented safety evaluation does not contain Sensitive Security-Related Information (SUNSI) pursuant to 10 CFR 2.390, “Public inspections, exemptions, requests for withholding.” In accordance with 10 CFR 2.390 of the NRC's "Agency Rules of Practice and Procedure," a copy of this letter will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of ADAMS. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

A copy of the related Safety Evaluation is provided in Enclosure 4. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice. If you have any questions, please contact me at 301 -415-3178, or via e-mail at marlayna.vaaler@nrc.gov.

Sincerely,

Marlayna G. Vaaler, Project Manager
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery
and Waste Programs
Office of Nuclear Material Safety and Safeguards

Docket Nos. 50-206, 50-361, and 50-362

Enclosures:
1. Amendment No. 168 to DPR-13
2. Amendment No. 236 to NPF-10
3. Amendment No. 229 to NPF-15
4. Safety Evaluation

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

DOCKET NO. 50-206

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 168
License No. DPR-13

1. The Nuclear Regulatory Commission (the Commission or the NRC) has found that:

   A. The application for a license amendment filed by the Southern California Edison Company and the San Diego Gas and Electric Company (the licensee), dated December 15, 2016, as supplemented by letter dated May 5, 2017, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and applicable portions of the Commission's regulations set forth in 10 CFR Chapter I, and all required notifications to other agencies or bodies have been duly made;

   B. Construction of San Onofre Nuclear Generating Station, Unit 1 (the facility) has been completed in conformity with Construction Permit No. CPPR-13 and the application, as amended, the provisions of the Act, and the regulations of the Commission;

   C. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the applicable rules and regulations of the Commission;

   D. There is reasonable assurance (i) that the activities authorized by this amended license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with applicable portions of the Commission's regulations set forth in 10 CFR Chapter I;

   E. The licensee is technically qualified to engage in the activities authorized by this license in accordance with the Commission's regulations set forth in 10 CFR Chapter I;

Enclosure 1

F. The licensee has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public;

H. The issuance of this license is in accordance with 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," of the Commission's regulations and all applicable requirements have been satisfied; and

I. The possession of source, byproduct, and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40, and 70.

2. Accordingly, the license is amended by changes to paragraph 2.C(2) of Facility Operating License No. DPR-13, and is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 168, are hereby incorporated in the license. Southern California Edison Company shall maintain the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days following SCE's submittal of a written certification to the NRC that all spent nuclear fuel assemblies have been transferred out of the spent fuel pools and placed in storage within the onsite ISFSI.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce A. Watson, CHP, Chief
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery
and Waste Programs
Office of Nuclear Material Safety and Safeguards

Attachment:
Change to Facility
Operating License No. DPR-13

Date of Issuance: November , 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 168

TO FACILITY OPERATING LICENSE NO. DPR-13

DOCKET NO. 50-206

Replace the following page of the Facility Operating License No. DPR-13 with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the area of change.

Facility Operating License No DPR-13

REMOVE	INSERT
3	3

chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Act and the applicable provisions of the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is not authorized to operate the facility as a nuclear reactor.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 168, are hereby incorporated in the license. Southern California Edison Company shall maintain the facility in accordance with the Technical.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

DOCKET NO. 50-361

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 236
License No. NPF-10

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Southern California Edison Company, et al. (SCE or the licensee), dated December 15, 2016, as supplemented by letter dated May 5, 2017, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, as supplemented, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 2

2. Accordingly, the license is amended by changes to paragraph 2.C(2) of Facility Operating License No. NPF-10, and is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 236, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days following SCE's submittal of a written certification to the NRC that all spent nuclear fuel assemblies have been transferred out of the spent fuel pools and placed in storage within the onsite ISFSI.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce A. Watson, CHP, Chief
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery
and Waste Programs
Office of Nuclear Material Safety and Safeguards

Attachment:
Change to Facility
Operating License No. NPF-10

Date of Issuance: November , 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 236

TO FACILITY OPERATING LICENSE NO. NPF-10

DOCKET NO. 50-361

Replace the following page of the Facility Operating License No. NPF-10 with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the area of change.

Facility Operating License No NPF-10

REMOVE	INSERT
3	3

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

(5) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of San Onofre Nuclear Generating Station, Units 1 and 2 and by the decommissioning of San Onofre Nuclear Generating Station Unit 1.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Deleted

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 236, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

DOCKET NO. 50-362

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 229
License No. NPF-15

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Southern California Edison Company, et al. (SCE or the licensee), dated December 15, 2016, as supplemented by letter dated May 5, 2017, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, as supplemented, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," of the Commission's regulations and all applicable requirements have been satisfied.

Enclosure 3

2. Accordingly, the license is amended by changes to paragraph 2.C(2) of Facility Operating License No. NPF-15, and is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 229, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days following SCE's submittal of a written certification to the NRC that all spent nuclear fuel assemblies have been transferred out of the spent fuel pools and placed in storage within the onsite ISFSI.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce A. Watson, CHP, Chief
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery
and Waste Programs
Office of Nuclear Material Safety and Safeguards

Attachment:
Change to Facility
Operating License No. NPF-15

Date of Issuance: November , 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 229

TO FACILITY OPERATING LICENSE NO. NPF-15

DOCKET NO. 50-362

Replace the following page of the Facility Operating License No. NPF-15 with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the area of change.

Facility Operating License No. NPF-15

REMOVE	INSERT
3	3

(3) SCE, pursuant to the Act and 10 CFR Part 70, to possess at any time special nuclear material that was used as reactor fuel, in accordance with the limitations for storage, as described in the Final Safety Analysis Report, as supplemented and amended;

(4) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; and possess any byproduct, source and special material as sealed neutron sources that was used for reactor startup;

(5) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) SCE, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of San Onofre Nuclear Generating Station, Units 1 and 2 and by the decommissioning of San Onofre Nuclear Generating Station Unit 1.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Deleted

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 229, are hereby incorporated in the license. Southern California Edison Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF

NUCLEAR SECURITY AND INCIDENT RESPONSE

RELATED TO AMENDMENT NO. 168 TO FACILITY OPERATING LICENSE NO. DPR-13

AND AMENDMENT NO. 236 TO FACILITY OPERATING LICENSE NO. NPF-10

AND AMENDMENT NO. 229 TO FACILITY OPERATING LICENSE NO. NPF-15

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3

DOCKET NOS. 50-206, 50-361, AND 50-362

1.0 INTRODUCTION

The San Onofre Nuclear Generating Station (SONGS), Units 1, 2 and 3, are decommissioning nuclear power reactor units located in San Diego County, California, approximately 62 miles southeast of Los Angeles, and approximately 51 miles northwest of San Diego, on an 84 acre site located entirely within the Camp Pendleton Marine Corps Base. The licensee, Southern California Edison (SCE), is the holder of Facility Operating License Nos. DPR-13 (Unit 1), NPF-10 (Unit 2) and NPF-15 (Unit 3), which were issued pursuant to the Atomic Energy Act of 1954, as amended, and Part 50, "Domestic Licensing of Production and Utilization Facilities," of Title 10 of the *Code of Federal Regulations* (10 CFR).

SONGS, Unit 1, was granted its provisional operating license by the U.S. Nuclear Regulatory Commission (NRC) on January 1, 1968 (Reference 1), and ceased operation on November 30, 1992 (Reference 2). The licensee completed defueling on March 6, 1993 (Reference 3), and maintained the unit in SAFSTOR until June 1999, when it initiated active decommissioning and dismantlement, or DECON (Reference 4). On December 28, 1993 (Reference 5), the NRC approved the Permanently Defueled Technical Specifications for SONGS, Unit 1. SCE submitted the proposed Decommissioning Plan for SONGS, Unit 1, on November 3, 1994 (Reference 6). As a result of the 1996 revision to the regulations in 10 CFR 50.82, "Termination of license," the NRC replaced the requirement for a decommissioning plan with a requirement for a Post Shutdown Decommissioning Activities Report (PSDAR). On August 28, 1996, the SONGS, Unit 1, Decommissioning Plan became the

Enclosure 4

SONGS 1 PSDAR (61 FR 67079; December 19, 1996). On December 15, 1998 (Reference 7), SCE submitted an update to the PSDAR to the NRC, as required by 10 CFR 50.82(a)(7), in order to begin planning for the dismantlement and decommissioning of SONGS, Unit 1. Dismantlement of SONGS, Unit 1, is essentially complete and most of the structures and equipment have been removed and sent to a nuclear waste disposal facility. All of the SONGS, Unit 1, fuel is being stored in the onsite independent spent fuel storage installation (ISFSI).

By letter dated June 12, 2013 (Reference 8), SCE submitted a certification to the NRC indicating its intention to permanently cease power operations at SONGS, Units 2 and 3, as of June 7, 2013, pursuant to 10 CFR 50.82(a)(1)(i). By letters dated June 28, 2013 (Reference 9), and July 22, 2013 (Reference 10), SCE submitted certifications of permanent removal of fuel from the Unit 3 and Unit 2 reactor vessels as of October 5, 2012, and July 18, 2013, respectively, pursuant to 10 CFR 50.82(a)(1)(ii). Upon docketing of these certifications, and pursuant to 10 CFR 50.82(a)(2), the SONGS, Units 2 and 3, facility operating licenses no longer authorize operation of the reactors or emplacement or retention of fuel into the reactor vessels.

By application dated December 15, 2016 (Reference 11), as supplemented by letter dated May 5, 2017 (Reference 12), the licensee requested changes to the SONGS Permanently Defueled Emergency Plan (PDEP) pursuant to 10 CFR 50.54(q), “Emergency plans.” The proposed changes replace the SONGS PDEP and associated Emergency Action Level (EAL) Bases Manual (hereafter referred to as the EAL scheme) with an ISFSI-Only Emergency Plan (IOEP) and associated EAL scheme. The NRC staff determined that the proposed SONGS IOEP and associated EAL changes continue to meet the standards in 10 CFR 50.47, “Emergency plans,” and the requirements in Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” of 10 CFR Part 50, as exempted. As such, the SONGS IOEP and associated EAL changes provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency.

The proposed changes more fully reflect the decommissioning status of the facility, as well as the reduced scope of potential radiological accidents once all spent fuel has been moved to dry cask storage within the onsite ISFSI, an activity which is currently scheduled for completion in 2019. The supplement to the current application, dated May 5, 2017, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on February 14, 2017 (82 FR 10601).

2.0 REGULATORY EVALUATION

This safety evaluation assesses the acceptability of the proposed SONGS ISFSI-Only IOEP and associated EAL scheme. This plan would replace the current SONGS PDEP and associated EAL scheme after all of the SONGS, Units 2 and 3, spent fuel has been transferred from the spent fuel pools (SFPs) to the expanded onsite ISFSI. The regulatory requirements, as exempted by letter dated June 4, 2015 (Reference 13), and associated guidance on which the NRC based its acceptance and evaluation are as follows:

2.1 NRC Regulations

- 10 CFR 50.47(b)(1), as exempted, states, in part: "... each principal response organization has staff to respond and to augment its initial response on a continuous basis;"

- 10 CFR 50.47(b)(2) states, in part: "... adequate staffing to provide initial facility accident response in key functional areas is maintained at all times, timely augmentation of response capabilities is available ...;"

- 10 CFR 50.47(b)(4), as exempted, states, in part: "A standard emergency classification and action level scheme, the bases of which include facility system and effluent parameters, is in use by the nuclear facility licensee…;"

- 10 CFR Part 50, Appendix E, Section IV.A, as exempted, states, in part: "The organization for coping with radiological emergencies shall be described, including definition of authorities, responsibilities, and duties of individuals assigned to the licensee's emergency organization…;"

- 10 CFR Part 50, Appendix E, Section IV.C.1, as exempted, states, in part: "The emergency classes defined shall include (1) notification of unusual events, (2) alert…;"

- 10 CFR 72.32, "Emergency Plan," Section (a)(3), states: "A classification system for classifying accidents as 'Alerts';" and

- 10 CFR 72.32(a)(7) states, in part: "A brief description of the responsibilities of licensee personnel should an accident occur…."

2.2 Regulatory Guidance

- Revision 1 to NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (Reference 14), provides a common reference and guidance source for nuclear facility operators to develop radiological emergency response plans.

- Office of Nuclear Security and Incident Response / Division of Preparedness and Response (NSIR/DPR) Interim Staff Guidance (ISG) – 2, "Emergency Planning Exemption Requests for Decommissioning Nuclear Power Plants" (Reference 15), provides guidance for the review of permanently defueled emergency plans for power reactor sites undergoing decommissioning.

- Office of Nuclear Materials Safety and Safeguards / Spent Fuel Project Office (NMSS/SFPO) ISG – 16, "Emergency Planning" (Reference 16), provides emergency plan review guidance applicable to facilities licensed pursuant to the regulatory requirements found at 10 CFR Part 72, "Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste."

- Nuclear Energy Institute (NEI) document NEI 99-01, Revision 6, "Development of Emergency Action Levels for Non-Passive Reactors" (Reference 17), endorsed by the NRC in a letter dated March 28, 2013 (Reference 18), as generic (non-plant-specific) EAL scheme development guidance.

3.0 TECHNICAL EVALUATION

The NRC staff has reviewed the licensee's regulatory and technical analyses in support of its proposed emergency plan changes, as described in the application dated December 15, 2016, as supplemented by letter dated May 5, 2017. The technical evaluation is detailed below.

3.1 Background

SONGS, Unit 1, has been permanently shutdown since November 30, 1992, and the final removal of fuel from its reactor vessel was completed on March 6, 1993. SONGS, Units 2 and 3, have been shutdown since January 2012, and SCE submitted certifications of permanent removal of fuel from the Unit 3 and Unit 2 reactor vessels as of October 5, 2012, and July 18, 2013, respectively. SONGS is authorized to possess and store irradiated nuclear fuel at the permanently shutdown and defueled SONGS facility. The spent fuel from SONGS, Unit 1, is stored in the onsite ISFSI and at the General Electric-Hitachi Nuclear Energy Americas, LLC, Morris Operation facility (Docket No. 72-01) located in Morris, Illinois. After the SONGS, Units 2 and 3, reactors were shutdown, all fuel assemblies were removed from the reactor vessels and placed in the SONGS SFPs.

By letter dated March 31, 2014 (Reference 19), as supplemented by letters dated September 9, 2014 (Reference 20), October 2, 2014 (Reference 21), October 7, 2014 (Reference 22), October 27, 2014 (Reference 23), November 3, 2014 (Reference 24), and December 15, 2014 (Reference 25), SCE requested exemptions for SONGS from (1) certain planning standards in 10 CFR 50.47(b) regarding onsite and offsite radiological emergency plans for nuclear power reactors; (2) certain requirements in 10 CFR 50.47(c)(2) that require establishment of plume exposure and ingestion pathway emergency planning zones for nuclear power reactors, and (3) certain requirements in 10 CFR Part 50, Appendix E, Section IV, regarding the content of emergency plans. The NRC approved the requested exemptions in a letter dated June 4, 2015 (Reference 13).

By letters dated June 5, 2015, the NRC issued Amendment No. 166 to Facility Operating License No. DPR-13, Amendment No. 228 to Facility Operating License No. NPF-10, and Amendment No. 221 to Facility Operating License No. NPF-15 for SONGS, Units 1, 2 and 3, respectively, and the ISFSI, for changes to the EAL scheme (Reference 26), and Amendment No. 167 to Facility Operating License No. DPR-13, Amendment No. 229 to Facility Operating License No. NPF-10, and Amendment No. 222 to Facility Operating License No. NPF-15 for SONGS, Units 1, 2, and 3, respectively, and the ISFSI, for changes to the emergency plan (Reference 27). The PDEP and EAL scheme were fully implemented on July 8, 2015 (Reference 28), in accordance with the above-referenced license amendments.

3.2 Proposed Changes

In its application dated December 15, 2016 (Reference 11), as supplemented by letter dated May 5, 2017 (Reference 12), SCE requested that the NRC review and approve a proposed IOEP, including a proposed ISFSI-Only EAL scheme, that is based on NEI 99-01, Revision 6 (Reference 17). The proposed amendments would replace the existing SONGS PDEP and associated EAL scheme, which currently reflect spent fuel from SONGS, Units 1, 2, and 3, being stored in the SFPs and onsite ISFSI. The major changes that SCE is requesting are: (1) removal of the various emergency actions related to the SFPs; (2) removal of non-ISFSI related emergency event types; (3) replacing the "Shift Manager" title with the "ISFSI Shift Supervisor (ISS)" title as the position that assumes the Emergency Director's responsibilities; and (4) a revision to the SONGS Emergency Response Organization (ERO).

The proposed changes modify the scope of onsite emergency preparedness requirements to reflect the reduced potential radiological accidents with all spent fuel in dry cask storage within the ISFSI. The off-normal events and accidents addressed in the SONGS IOEP are related to the dry storage of spent nuclear fuel at the ISFSI, and include only off-normal, accident, natural phenomena, and hypothetical events and consequences affecting the SONGS ISFSI.

Under the previous facility condition with spent fuel stored within the SONGS SFPs, the most severe postulated beyond-design-basis accident involved a highly unlikely sequence of events that cause a heat-up of the spent fuel, postulated to occur without heat transfer, such that the zircaloy fuel cladding reaches ignition temperature. While highly improbable, the resultant zircaloy fire could lead to the release of large quantities of fission products to the atmosphere. However, after removal of the spent fuel from the SONGS SFPs, the age and configuration of spent fuel stored in dry cask storage precludes the possibility of such a zircaloy fire scenario. After all the spent fuel is transferred to dry cask storage within the SONGS ISFSI, the number and severity of potential radiological accidents is significantly less than when spent fuel was stored in the SFPs. For these reasons, the potential radiological consequences of accidents possible at SONGS after all spent fuel is transferred to the ISFSI are further reduced.

There continues to be no need for formal offsite radiological emergency preparedness (REP) plans under 44 CFR Part 350 at SONGS because no design-basis accident or reasonably credible beyond-design-basis accident can result in radioactive releases that exceed the U.S. Environmental Protection Agency (EPA) Early Phase Protective Action Guides (PAGs) (Reference 29) beyond the exclusion area boundary.

3.3 Evaluation

The NRC staff reviewed the changes from the current SONGS PDEP to the proposed IOEP and ISFSI-Only EAL scheme, including the licensee's evaluation of the changes, to verify that the proposed IOEP and EAL scheme continue to meet the standards contained in 10 CFR 50.47(b) and the requirements of Appendix E to 10 CFR Part 50, as exempted, applicable to the approved 10 CFR Part 50 emergency plan for the long-term defueled conditions at SONGS. The NRC staff also performed a review to ensure that the proposed IOEP would be consistent with the requirements of 10 CFR 72.32 for an ISFSI not located on the site of an operating nuclear power reactor. Although the requirements of 10 CFR 72.32 do not apply to a 10 CFR

Part 50 licensee, such as SONGS, the NRC uses these regulations as guidance to promote consistency between specifically licensed and generally licensed ISFSIs.

3.3.1 *ISFSI EALs and Removal of SFP Initiating Conditions and EALs*

The initiating conditions (ICs) and EALs associated with the emergency classification levels in the current PDEP are based on Appendix C to NEI 99-01, Revision 6 (Reference 17), which addresses a nuclear power reactor that has permanently ceased operations and transferred spent fuel from the reactor vessel to the SFPs (permanently defueled). After all spent fuel has been removed from the SFPs and placed in dry cask storage within the ISFSI, the ICs and EALs in Appendix C to NEI 99-01 that are associated with the SFPs at a decommissioning facility are no longer required. Additionally, certain ICs and EALs whose primary function is not associated with the SFPs are no longer required when administrative controls are established to limit source term accumulation and the offsite consequences of uncontrolled effluent releases.

Examples of administrative controls for radiological source term accumulation limits and methods to control the accidental dispersal of the radiological source are:

- Limits on radioactive materials collected on filter media and resins (dose rate limit);
- Limits on surface or fixed contamination on work areas that may create airborne radioactive material (activity limits), and
- Limiting dispersal mechanisms that may cause a fire (e.g., limits on combustible material loading, use of a fire watch to preclude fires, etc.) or placement of a berm around a radioactive liquid storage tank.

Other ICs proposed for deletion include those associated with the mitigative strategies contained in certain SCE license conditions, as well as response procedures for potential or actual aircraft attacks. These will be eliminated after all spent fuel is removed from the SFPs and stored in the onsite SONGS ISFSI. The ICs listed in Table 1 below are being deleted, either partially or in their entirety as indicated, from the PDEP and EAL scheme for SONGS. The ICs being deleted are either associated only with SFP operation or are ICs for which administrative controls to limit possible effluent releases have been established.

Table 1: Initiating Conditions to be Deleted or Modified

ALERT	UNUSUAL EVENT
PD-AA1 (all EALs) Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 millirems (mrem) total effective dose equivalent (TEDE) or 50 mrem committed dose equivalent (CDE).	**PD-AU1 (all EALs)** Release of gaseous or liquid radioactivity greater than 2 times the Offsite Dose Calculation Manual (ODCM) limit for 60 minutes or longer.

PD-AA2 (all EALs) UNPLANNED rise in plant radiation levels that impedes plant access required to maintain spent fuel integrity.	**PD-AU2 (all EALs)** UNPLANNED rise in plant radiation levels.
PD-HA1* HOSTILE ACTION within the Vehicle Barrier System (VBS) boundary ~~or airborne attack threat within 30 minutes~~.	**PD-SU1 (all EALs)** UNPLANNED spent fuel pool temperature rise.
PD-HA1.2 A validated notification from the NRC of an aircraft attack threat within 30 minutes of the site.	**PD-HU1.3** A validated notification from the NRC providing information of an aircraft attack threat.
	PD-HU2 (all EALs)** Hazardous event affecting SAFETY SYSTEM equipment necessary for spent fuel cooling.

* Only the strike-through portion is being deleted.

** For an ISFSI-only facility, the condition addressed by PD-HU2 remains fully addressed by IC EU1.1 (which is being retained in the SONGS emergency plan).

The currently existing SONGS ICs and EALs not listed in Table 1 are being retained. The EAL ICs being deleted include all ICs associated with the categories of abnormal radioactivity release and system malfunction. These two categories apply only to SFP operation. The EAL ICs being retained in the SONGS IOEP are appropriate to address the condition of an ISFSI-only facility (i.e., no fuel stored in the spent fuel pools).

The SONGS ICs and EALs to be retained are listed in Table 2, and include one new EAL being proposed in IC E-HU1, "Damage to a loaded cask CONFINEMENT BOUNDARY," which bounds the deleted ICs. In addition, the new EAL E-HU1.2 provides threshold values for the AREVA ISFSI and the new HOLTEC ISFSI at SONGS, based on the generic AREVA and HOLTEC Technical Specification values provided in the respective Certificates of Compliance.

Table 2: Initiating Conditions to be Maintained or Added

ALERT	UNUSUAL EVENT
Independent Spent Fuel Storage Installation (ISFSI)	
PD-HA1 HOSTILE ACTION within the VBS boundary.	**PD-HU1** Confirmed SECURITY CONDITION or threat.

PD-HA1.1 A HOSTILE ACTION is occurring or has occurred within the VBS boundary as reported by the SSS [Security Shift Supervisor].	**PD-HU1.1** A SECURITY CONDITION that does not involve a HOSTILE ACTION as reported by the SSS. **PD-HU1.2** Notification of a credible security threat directed at the site.
PD-HA3 Other conditions exist which in the judgement of the ISS/ED [Emergency Director] warrant declaration of an ALERT. **PD-HA3.1** Other conditions exist which in the judgment of the ISS/ED indicate that events are in progress or have occurred which involve an actual or potential substantial degradation of the level of safety of the ISFSI or a security event that involves probable life threatening risk to site personnel or damage to ISFSI equipment because of HOSTILE ACTION. Any releases are expected to be limited to small fractions of the EPA Protective Action Guide exposure levels.	**PD-HU3** Other conditions exist which in the judgment of the ISS/ED warrant declaration of an UNUSUAL EVENT. **PD-HU3.1** Other conditions exist which in the judgment of the ISS/ED indicate that events are in progress or have occurred which indicate a potential degradation of the level of safety of the ISFSI or indicate a security threat to the ISFSI has been initiated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation occurs.
	E-HU1 Damage to a loaded canister CONFINEMENT BOUNDARY. **E-HU1.1** Damage to a loaded Transnuclear canister CONFINEMENT BOUNDARY as indicated by dose rates greater than EITHER of the following: • 520 milliroentgen per hour (mR/hr) (gamma) 3 feet from the surface at the top centerline. • 190 mR/hr (gamma) 3 feet from the surface of the neutron shield at the mid-height centerline. **E-HU1.2** Damage to a loaded Holtec canister CONFINEMENT BOUNDARY as indicated by dose rates greater than EITHER of the following: • 60 mR/hr (gamma + neutron) on the top of the closure lid of a VVM [Vertical Ventilated Module], measured in accordance with the EAL Technical Basis.

	• 7000 mR/hr (gamma + neutron) on the side of a TRANSFER CASK, measured in accordance with the EAL Technical Basis.

The most severe beyond-design-basis accident postulated for SONGS with spent fuel stored within the SFPs involved a highly unlikely sequence of events that cause heat-up of the spent fuel, postulated to occur without heat transfer, such that the zircaloy fuel cladding reaches ignition temperature. Because this limiting, beyond-design-basis scenario is no longer possible due to the transfer of spent fuel from the SFPs to dry cask storage in the onsite ISFSI, SCE assessed the following design-basis accidents associated with the performance of decommissioning activities with all irradiated fuel stored in the SONGS ISFSI: (1) cask drop accident (fuel related accident); (2) radioactive material handling accident (non-fuel related), and (3) accidents initiated by external events. For design-basis accident scenarios (1) and (2), the results of the assessment indicate that the projected radiological doses at the exclusion area boundary are less than the EPA PAGs. The effects of external events, such as fires, floods, wind (including tornados), earthquakes, lightning, and physical security breaches on the SONGS ISFSI that could affect the confinement boundary of the ISFSI remain unchanged from the effects that were considered under the existing PDEP.

As discussed in the June 4, 2015, exemption from certain emergency preparedness requirements (Reference 13), an analysis of the potential radiological impacts of a design-basis accident at SONGS in a permanently defueled condition indicated that any releases beyond the exclusion area boundary were below the EPA PAG exposure levels. The basis for these exemptions has not changed and remains in effect for the proposed emergency plan changes.

Because of the very low risk of consequences to public health and safety resulting from the postulated accidents related to the SONGS ISFSI, no potential emergencies are classified as higher than an Alert, in accordance with the requirements of 10 CFR Part 50, Appendix E, Section IV.C.1, as exempted. Classification of emergencies as no higher than an Alert also maintains consistency with the regulations in 10 CFR 72.32(a)(3), “Classification of accidents.”

Based on the NRC staff’s review of the SONGS IOEP and associated EAL scheme, as described above, the NRC staff concludes that the planning standard of 10 CFR 50.47(b)(4), as exempted, pertaining to a standard emergency classification and action level scheme, is addressed in an acceptable manner in the SONGS IOEP, considering the permanently shutdown and defueled status of the facility, and the proposed transfer of all remaining spent fuel from the SONGS SFPs to the ISFSI by 2019.

3.3.2 *SONGS Emergency Response Organization Revision*

The existing SONGS PDEP provides for two (2) ERO augmented positions – a Duty ERO Coordinator and a Radiation Control Coordinator. The proposed SONGS IOEP would replace these positions with a Resource Manager. The Resource Manager will assist in assessing the event and coordinating required resources, including public information interface. The Resource Manager will be in contact with the Emergency Director within two hours of classification of an Unusual Event or an Alert. The Resource Manager does not need to physically report to SONGS to perform their responsibilities. In addition, SCE proposes that, for

a declared emergency involving radiological consequences (E-HU1), a minimum of one person trained in radiological monitoring and assessment will report to the SONGS ISFSI within four hours of the emergency declaration. Supplemental personnel shall report at the discretion of the Emergency Director and/or Resource Manager.

In its evaluation of the proposed changes to the SONGS ERO, the NRC staff considered the accident analyses referenced in the previous section related to the deletion of EALs, either partially or in their entirety, as indicated, as they relate to SFP operation. Specifically, the NRC staff considered the postulated accidents that could occur with all spent fuel moved into the SONGS ISFSI, which pose a very low risk to public health and safety. The staff notes that SCE also continues to commit to maintain the appropriate level of augmented response to an emergency, to include an event involving radiological consequences.

In the Statement of Considerations for the Final Rule for Emergency Planning Licensing Requirements for Independent Spent Fuel Storage Facilities and Monitored Retrievable Storage Facilities (MRS) (60 FR 32430; June 22, 1995), the Commission stated, in part:

> For there to be a significant environmental impact resulting from an accident involving the dry storage of spent nuclear fuel, a significant amount of the radioactive material contained within a cask must escape its packaging and enter the biosphere. There are two primary factors that protect the public health and safety from this event. The first is the design requirements for the cask that are imposed by regulation.
>
> These general design criteria place an upper bound on the energy a cask can absorb before the fuel is damaged. No credible dynamic events have been identified that could impart such significant amounts of energy to a storage cask after that cask is placed at the ISFSI.
>
> Additionally, there is a second factor which does not rely upon the cask itself but considers the age of the spent fuel and the lack of dispersal mechanisms. There exists no significant dispersal mechanism for the radioactive material contained within a storage cask.
>
> . . .
>
> Based on the design limitations, the majority of spent fuel is cooled greater than 5 years. At this age, spent fuel has a heat generation rate that is too low to cause significant particulate dispersal in the unlikely event of a cask confinement boundary failure.

Although the SONGS spent fuel analysis has not been able to identify any design-basis accident that would result in a failure of the confinement barrier for the dry storage casks or the irradiated fuel itself, the SONGS IOEP nonetheless requires augmentation of one person trained in radiological monitoring and assessment, who will report to the station within four hours of the emergency declaration for an event involving radiological consequences.

The proposed SONGS IOEP also provides that additional personnel resources may be directed to report to the plant to provide support, as needed, to assess radiological conditions, support maintenance and repair activities, develop and implement corrective action plans, and assist with recovery actions. The supplemental personnel are available from SONGS staff and SCE, and can also be requested from various contractors.

Based on the NRC staff's review of the SONGS IOEP, as described above, the NRC staff concludes that the planning standard of 10 CFR 50.47(b)(2), pertaining to timely augmentation of response capabilities, is addressed in an acceptable manner in the SONGS IOEP, considering the permanently shutdown and defueled status of the facility, and the proposed transfer of all remaining spent fuel from the SFPs to the ISFSI by 2019.

3.3.3 *Replacement of the "Shift Manager" Title with the "ISFSI Shift Supervisor" Title*

SCE revised Section 2.1, "On-Shift Positions," in the SONGS IOEP to reassign the following Emergency Director responsibilities from the Shift Manager to the ISFSI Shift Supervisor:

- Event classification and emergency declaration;
- Decision to notify offsite agencies;
- Authorization for the use of EPA-400 emergency exposure controls (emergency worker dose limits that exceed 10 CFR Part 20 occupational exposure limits);
- Management of available station resources;
- Initiation of assessment and mitigative / corrective actions;
- Initiation of onsite protective actions;
- Decision to call for offsite law enforcement, firefighting, or ambulance assistance;
- Augmentation of the emergency response organization as deemed necessary;
- Notification of SCE corporate officers and the SCE corporate communications department, and
- Notification of offsite agencies (State and local government agencies, Marine Corps Base Camp Pendleton and the NRC).

The NRC staff evaluation verified that the retitled position of ISFSI Shift Supervisor is on-shift at the SONGS site 24-hours a day / 7 days a week, and also serves as the senior management position during off-hours. This position assumes overall command and control of event response as the Emergency Director, and is responsible for monitoring conditions and approving all onsite activities. The SONGS IOEP clearly identifies non-delegable responsibilities, along with other designated tasks, for the ISFSI Shift Supervisor. The NRC staff considers this retitling activity to be an administrative change that will not impact the timing or performance of existing emergency response duties.

Based on the NRC staff's review of the SONGS IOEP, as described above, the NRC staff concludes that the requirements of 10 CFR Part 50, Appendix E, Section IV.A, as exempted, pertaining to responsibilities and duties of individuals assigned to the licensee's emergency organization, are addressed in a satisfactory manner, considering the permanently shutdown and defueled status of the facility, and the proposed transfer of all remaining spent fuel from the SONGS SFPs to the ISFSI by 2019.

4.0 ENVIRONMENTAL CONSIDERATION

The amendments include changes to requirements with respect to installation or use of a facility component located within the protected area and changes to recordkeeping, reporting, or administrative procedures or requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there have been no public comment on such finding, which was published in the *Federal Register* on February 14, 2017 (82 FR 10601). Accordingly, the amendments meet the eligibility criteria for categorical exclusions set forth in 10 CFR 51.22(c)(9) and 10 CFR 51.22(c)(10)(ii). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

5.0 STATE CONSULTATION

On November 5, 2017, the NRC staff notified the California State officials, Mr. Ira Schneider, Senior Health Physicist, Medical, Academic and Pharmacy Licensing, Radiologic Health Branch, California Department of Public Health; and Mr. Robert Weisenmiller, California State Liaison Officer, Commissioner, California Energy Commission, regarding the proposed change to approve the SONGS IOEP and associated EAL scheme to reflect the transfer of all spent fuel into dry cas storage at the onsite ISFSI. The California State officials responded on XXXXX XX, 2017, and XXXXX XX, 2017, with no comments.

6.0 CONCLUSION

Based on the its review of the proposed SONGS IOEP and associated EAL scheme, the NRC staff finds that the proposed changes continue to meet the standards in 10 CFR 50.47(b) and the requirements in Appendix E of 10 CFR Part 50, as exempted. The staff finds continued reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at the SONGS facility. In addition, the NRC staff concludes that the SONGS IOEP will be consistent with the emergency planning requirements in 10 CFR Part 72 for an ISFSI not located on the site of an operating reactor. Therefore, the NRC staff concludes that the licensee's proposed changes to the SONGS IOEP and associated EAL scheme in its letter dated December 15, 2016, as supplemented by letter dated May 5, 2017, are acceptable.

The NRC staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there continues to be reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

1. Letter from the U.S. Nuclear Regulatory Commission, "Southern California Edison Company, et al, Docket No. 50-206, Issuance of Facility Operating License No.

DPR-13," dated September 26, 1991 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13309A138).

2. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-206, Request for Exemption from Full Funding Requirements of 10 CFR 50.75(e)(1)(ii), San Onofre Nuclear Generating Station, Unit 1," dated November 30, 1992 (ADAMS Accession No. ML13319B040).

3. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-206, Certification of Permanently Defueled Status, San Onofre Nuclear Generating Station, Unit 1," dated March 8, 1993 (ADAMS Accession No. ML13319B055).

4. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-206, Post Shutdown Decommissioning Activities Report, San Onofre Nuclear Generating Station, Unit 1," dated December 15, 1998 (ADAMS Accession No. ML13319B111).

5. Letter from the U.S. Nuclear Regulatory Commission to Southern California Edison, "Issuance of Amendment No. 155 for Facility Operating License No. DPR-13, San Onofre Nuclear Generating Station, Unit No. 1, Permanently Defueled Technical Specifications (TAC No. M86377)," dated December 28, 1993 (ADAMS Accession No. ML13319B059).

6. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-206, Proposed Decommissioning Plan, San Onofre Nuclear Generating Station, Unit 1," dated November 3, 1994 (ADAMS Accession No. ML13319B073).

7. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-206, Post Shutdown Decommissioning Activities Report, San Onofre Nuclear Generating Station, Unit 1," dated December 15, 1998 (ADAMS Accession No. ML13184A353).

8. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-361 and 50-362, Certification of Permanent Cessation of Power Operations, San Onofre Nuclear Generating Station, Units 2 and 3," dated June 12, 2013 (ADAMS Accession No. ML131640201).

9. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-362, Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station, Unit 3," dated June 28, 2013 (ADAMS Accession No. ML13183A391).

10. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket No. 50-361, Permanent Removal of Fuel from the Reactor Vessel, San Onofre Nuclear Generating Station, Unit 2," dated July 22, 2013 (ADAMS Accession No. ML13204A304).

11. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-361, 50-362, and 50-206, Amendment Applications 226, 273, and 258, Independent Spent Fuel Storage Installation (ISFSI) Only Emergency Plan (IOEP) and ISFSI-Only Emergency Action Level Scheme (IOEAL), San Onofre Nuclear Generating Station, Units 1, 2, and 3," dated December 15, 2016 (ADAMS Accession No. ML16355A015).

12 Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-361, 50-362, and 50-206, Response to a Request for Additional Information Regarding the License Amendment Request to Change the Emergency Plan and Emergency Action level Scheme to Reflect an ISFSI-Only Configuration, San Onofre Nuclear Generating Station, Units 1, 2, and 3," dated May 5, 2017 (ADAMS Accession No. ML17160A324).

13. Letter from the U.S. Nuclear Regulatory Commission to Southern California Edison, "San Onofre Nuclear Generating Station, Units 1, 2 and 3, and the Independent Spent Fuel Storage Installation – Exemptions From Certain Emergency Planning Requirements (TAC Nos. MF3835, MF3836, and MF3837)," dated June 4, 2015 (ADAMS Accession No. ML15082A143).

14. U.S. Nuclear Regulatory Commission and Federal Emergency Management Agency, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," NUREG-0654/FEMA-REP-1, Revision 1, dated November 1980 (ADAMS Accession No. ML040420012).

15. NSIR/DRP-ISG-2, "Emergency Planning Exemption Requests for Decommissioning Nuclear Power Plants," dated May 11, 2015 (ADAMS Accession No. ML14106A057).

16. NMSS/SFST-ISG-16, "Emergency Planning," dated June 14, 2000 (ADAMS Accession No. ML003724570).

17. NEI 99-01, "Development of Emergency Action Levels for Non-Passive Reactors," Revision 6, dated November 2012 (ADAMS Accession No. ML12326A805).

18 Letter from the U.S. Nuclear Regulatory Commission to NEI, "Technical Evaluation for the Endorsement of NEI 99-01, Revision 6," dated March 28, 2013 (ADAMS Accession No. ML12346A463).

19 Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Emergency Planning Exemption Request, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated March 31, 2014 (ADAMS Accession No. ML14092A332).

20 Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Response to Request for Additional Information Regarding Emergency Planning Exemption Request, San Onofre Nuclear

Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated September 9, 2014 (ADAMS Accession No. ML14258A003).

21. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Response to Request for Additional Information Regarding Emergency Planning Exemption Request, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated October 2, 2014 (ADAMS Accession No. ML14280A265).

22. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Response to Request for Additional Information Regarding Emergency Planning Exemption Request, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated October 7, 2014 (ADAMS Accession No. ML14287A228).

23. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Response to Requests for Clarification of October 6, 2014, RAI Responses Concerning Emergency Planning Exemption Request, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated October 27, 2014 (ADAMS Accession No. ML14303A257).

24. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Response to Request for Additional Information Regarding Emergency Planning Exemption Request, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated November 3, 2014 (ADAMS Accession No. ML14309A195).

25 Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-041, Redacted Version of Response to Request for Additional Information, Proposed Exemptions from Certain Portions of 10 CFR 50.47 and Appendix E, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated December 15, 2014 (ADAMS Accession No. ML14351A078).

26. Letter from the U.S. Nuclear Regulatory Commission to Southern California Edison, "San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation – Issuance of Amendments Re: Changes to the Emergency Action Level Scheme (TAC Nos. MF3838, MF3839, and MF3840)," dated June 5, 2015 (ADAMS Accession No. ML15105A349).

27. Letter from the U.S. Nuclear Regulatory Commission to Southern California Edison, "San Onofre Nuclear Generating Station, Units 1, 2, and 3, and Independent Spent Fuel Storage Installation – Issuance of Amendments Re: Changes to the Emergency Plan (TAC Nos. MF3841, MF3842, and MF3843)," dated June 5, 2015 (ADAMS Accession No. ML 15126A461).

28. Letter from Southern California Edison to the U.S. Nuclear Regulatory Commission, "Docket Nos. 50-206, 50-361, 50-362, and 72-41, Revisions 0 and 1 to the Permanently Defueled Emergency Plan and Revisions to the Emergency Plan Implementing Procedures, San Onofre Nuclear Generating Station, Units 1, 2, and 3, and the Independent Spent Fuel Storage Installation," dated July 8, 2015 (ADAMS Accession No. ML15191A391).

29. U.S. Environmental Protection Agency PAG Manual, "Protective Action Guides and Planning Guidance for Radiological Incidents," dated January 2017 (ADAMS Accession No. ML17044A073).

Principal Contributor: Rick Kinard, NSIR

Dated: November , 2017

EXHIBIT 11

[7590-01-P]

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50-206, 50-361, and 50-362; NRC-2018-0004]

Southern California Edison Company

San Onofre Nuclear Generating Station, Units 1, 2, and 3

AGENCY: Nuclear Regulatory Commission.

ACTION: Exemption; issuance.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is issuing an exemption from the requirement to maintain a specified level of onsite property damage insurance in response to an October 22, 2015, request from the Southern California Edison Company (the licensee). Specifically, the licensee requested that the San Onofre Nuclear Generating Station, Units 1, 2, and 3, be granted an exemption to permit the licensee to reduce its onsite property damage insurance from $1.06 billion to $50 million.

ADDRESSES: Please refer to Docket ID **NRC-2018-0004** when contacting the NRC about the availability of information regarding this document. You may obtain publicly-available information related to this document using any of the following methods:

- **Federal Rulemaking Web Site:** Go to http://www.regulations.gov and search for Docket ID **NRC-2018-0004**. Address questions about NRC dockets to Carol Gallagher; telephone: 301-415-3463; e-mail: Carol.Gallagher@nrc.gov. For technical questions, contact the individual listed in the FOR FURTHER INFORMATION CONTACT section of this document.

- **NRC's Agencywide Documents Access and Management System (ADAMS):** You may obtain publicly available documents online in the ADAMS Public Documents collection at http://www.nrc.gov/reading-rm/adams.html. To begin the search, select "ADAMS Public Documents" and then select "Begin Web-based ADAMS Search." For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1-800-397-4209, 301-415-4737, or by e-mail to pdr.resource@nrc.gov. The ADAMS accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in this document.
- **NRC's PDR:** You may examine and purchase copies of public documents at the NRC's PDR, Room O1-F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

FOR FURTHER INFORMATION CONTACT: Marlayna Vaaler, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; telephone: 301-415-3178; e-mail: Marlayna.Vaaler@nrc.gov.

SUPPLEMENTARY INFORMATION:

I. Background

The San Onofre Nuclear Generating Station, Units 1, 2, and 3 (SONGS), operated by the Southern California Edison Company (SCE) is located approximately 4 miles south of San Clemente, California. The SONGS, Unit 1, Docket No. 50-206, was a Westinghouse 456 megawatt electric (MWe) pressurized water reactor which was granted Facility Operating License No. DPR-13 on January 1, 1968 (ADAMS Accession

No. ML13309A138), and ceased operation on November 30, 1992 (ADAMS Accession No. ML13319B040). The licensee completed defueling on March 6, 1993 (ADAMS Accession No. ML13319B055), and maintained the unit in SAFSTOR until June 1999, when it initiated decommissioning (ADAMS Accession No. ML13319B111). On December 28, 1993 (ADAMS Accession No. ML13319B059), the NRC approved the Permanently Defueled Technical Specifications for SONGS, Unit 1.

The SCE submitted the proposed Decommissioning Plan for SONGS, Unit 1, on November 3, 1994 (ADAMS Accession No. ML13319B073). As a result of the 1996 revision to the regulations in section 50.82 of title 10 of the *Code of Federal Regulations* (10 CFR), the NRC replaced the requirement for a decommissioning plan with a requirement for a Post Shutdown Decommissioning Activities Report (PSDAR). On August 28, 1996, the SONGS, Unit 1, Decommissioning Plan became the SONGS 1 PSDAR (61 FR 67079; December 19, 1996). On December 15, 1998 (ADAMS Accession No. ML13184A353), SCE submitted an update to the PSDAR to the NRC, as required by 10 CFR 50.82(a)(7), in order to begin planning for the dismantlement and decommissioning of SONGS, Unit 1.

The SONGS, Units 2 and 3, Docket Nos. 50-361 and 50-362, are Combustion Engineering 1127 MWe pressurized water reactors, which were granted Facility Operating Licenses NPF-10 on February 16, 1982, and NPF-15 on November 15, 1982, respectively. In June 2013, pursuant to 10 CFR 50.82(a)(1)(i), the licensee certified to the NRC that as of June 7, 2013, operations had ceased at SONGS, Units 2 and 3 (ADAMS Accession No. ML131640201). The licensee subsequently certified, pursuant to 10 CFR 50.82(a)(1)(ii), that all fuel had been removed from the reactor vessels of both units, and committed to maintaining the units in a permanently defueled status (ADAMS Accession Nos. ML13204A304 and ML13183A391 for Unit 2 and Unit 3, respectively).

Therefore, pursuant to 10 CFR 50.82(a)(2), SCE's 10 CFR part 50 licenses no longer authorize operation of SONGS or emplacement or retention of fuel into the reactor vessels. The licensee is still authorized to possess and store irradiated nuclear fuel. Irradiated fuel is currently being stored onsite in spent fuel pools (SFPs) and in dry casks at an Independent Spent Fuel Storage Installation (ISFSI).

The PSDAR for SONGS, Units 2 and 3, was submitted on September 23, 2014 (ADAMS Accession No. ML14272A121), and the associated public meeting was held on October 27, 2014, in Carlsbad, California (ADAMS Accession No. ML14352A063). The NRC confirmed its review of the SONGS, Units 2 and 3, PSDAR and addressed public comments in a letter dated August 20, 2015 (ADAMS Accession No. ML15204A383). On July 17, 2015, the NRC approved the Permanently Defueled Technical Specifications for SONGS, Units 2 and 3 (ADAMS Accession No. ML15139A390).

II. Request/Action

Pursuant to 10 CFR 50.12, "Specific exemptions," SCE requested an exemption from 10 CFR 50.54(w)(1), by letter dated October 22, 2015 (ADAMS Accession No. ML15299A220). The exemption from the requirements of 10 CFR 50.54(w)(1) would permit the licensee to reduce the required level of onsite property damage insurance from $1.06 billion to $50 million.

The regulation at 10 CFR 50.54(w)(1) requires each licensee to have and maintain onsite property damage insurance to stabilize and decontaminate the reactor and reactor site in the event of an accident. The onsite insurance coverage must be either $1.06 billion or whatever amount of insurance is generally available from private sources (whichever is less).

The licensee states that the risk of an incident at a permanently shutdown and defueled reactor is much less than the risk from an operating power reactor. In addition, since reactor operation is no longer authorized at SONGS, there are no events that would require the stabilization of reactor conditions after an accident. Similarly, the risk of an accident that that would result in significant onsite contamination at SONGS is also much lower than the risk of such an event at operating reactors. Therefore, SCE is requesting an exemption from 10 CFR 50.54(w)(1) to reduce its onsite property damage insurance from $1.06 billion to $50 million, commensurate with the reduced risk of an incident at the permanently shutdown and defueled SONGS site.

III. Discussion

Under 10 CFR 50.12, the Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of 10 CFR part 50 when (1) the exemptions are authorized by law, will not present an undue risk to public health or safety, and are consistent with the common defense and security; and (2) any of the special circumstances listed in 10 CFR 50.12(a)(2) are present.

The financial protection limits of 10 CFR 50.54(w)(1) were established after the Three Mile Island accident out of concern that licensees may be unable to financially cover onsite cleanup costs in the event of a major nuclear accident. The specified $1.06 billion coverage amount requirement was developed based on an analysis of an accident at a nuclear reactor operating at power, resulting in a large fission product release and requiring significant resource expenditures to stabilize the reactor and ultimately decontaminate and cleanup the site.

These cost estimates were developed based on the spectrum of postulated accidents for an operating nuclear reactor. Those costs were derived from the

consequences of a release of radioactive material from the reactor. Although the risk of an accident at an operating reactor is very low, the consequences onsite and offsite can be significant. In an operating plant, the high temperature and pressure of the reactor coolant system (RCS), as well as the inventory of relatively short-lived radionuclides, contribute to both the risk and consequences of an accident. With the permanent cessation of reactor operations at SONGS and the permanent removal of the fuel from the reactor cores, such accidents are no longer possible. As a result, the reactors, RCS, and supporting systems no longer operate and have no function related to the storage of the irradiated fuel. Therefore, postulated accidents involving failure or malfunction of the reactors, RCS, or supporting systems are no longer applicable.

As described in the PSDAR, SONGS, Unit 1, is being returned to a condition suitable for unrestricted use. According to SCE, there are no structures, systems, or components (SSCs) classified as safety-related remaining at SONGS, Unit 1. Plant dismantlement is complete and nearly all of the SSCs have been shipped offsite for disposal. Only the spent fuel, reactor vessel, and the below-grade portions of some buildings remain onsite. The principal remaining decommissioning activities are soil remediation, compaction, and grading. This is to be completed in conjunction with the future decommissioning of the ISFSI subsequent to shipment offsite of the SONGS stored spent fuel.

The licensee also stated that decommissioning of SONGS, Units 2 and 3, has begun and the nuclear reactors and essentially all associated SSCs in the nuclear steam supply system and balance of plant that supported the generation of power have been retired in place and are being prepared for removal. The SSCs that remain operable are associated with the SFPs and the spent fuel building, are needed to meet other regulatory requirements, or are needed to support other site facilities (e.g., radioactive

waste handling, ventilation and air conditioning, etc.). No remaining active SSCs are classified as safety-related.

During reactor decommissioning, the largest radiological risks are associated with the storage of spent fuel onsite. In its October 22, 2015, exemption request, SCE discusses both design-basis and beyond design-basis events involving irradiated fuel stored in the SFPs. The licensee determined that there are no possible design-basis events at SONGS that could result in an offsite radiological release exceeding the limits established by the U.S. Environmental Protection Agency's (EPA) early-phase Protective Action Guidelines (PAGs) of 1 rem (roentgen equivalent man) at the exclusion area boundary, as a way to demonstrate that any possible radiological releases would be minimal and not require precautionary protective actions (e.g., sheltering in place or evacuation). The staff evaluated the radiological consequences associated with various decommissioning activities, and design basis accidents at SONGS, in consideration of SONGS's permanently shut down and defueled status. The possible design-basis accident scenarios at SONGS have greatly reduced radiological consequences. Based on its review, the staff concluded that no reasonably conceivable design-basis accident exists that could cause an offsite release greater than the EPA PAGs.

The only incident that might lead to a significant radiological release at a decommissioning reactor is a zirconium fire. The zirconium fire scenario is a postulated, but highly unlikely, beyond design-basis accident scenario that involves loss of water inventory from the SFP, resulting in a significant heat-up of the spent fuel, and culminating in substantial zirconium cladding oxidation and fuel damage. The probability of a zirconium fire scenario is related to the decay heat of the irradiated fuel stored in the SFP. Therefore, the risks from a zirconium fire scenario continue to decrease as a function of the time that SONGS has been permanently shut down. The licensee

provided a detailed analysis of hypothetical beyond-design-basis accidents that could result in a radiological release at SONGS in its March 31, 2014, submittal to the NRC (ADAMS Accession No. ML14092A332), as supplemented by letters dated September 9, October 2, October 7, October 27, November 3, and December 15, 2014 (ADAMS Accession Nos. ML14258A003, ML14280A265, ML14287A228, ML14303A257, ML14309A195, and ML14351A078, respectively). One of these beyond design-basis accidents involves a complete loss of SFP water inventory, where cooling of the spent fuel would be primarily accomplished by natural circulation of air through the uncovered spent fuel assemblies. The licensee's analysis of this accident shows that by August 31, 2014, air-cooling of the spent fuel assemblies will be sufficient to keep the fuel within a safe temperature range indefinitely without fuel damage or offsite radiological release.

The Commission has previously authorized a lesser amount of onsite financial protection, based on this analysis of the zirconium fire risk. In SECY-96-256, "Changes to Financial Protection Requirements for Permanently Shutdown Nuclear Power Reactors, 10 CFR 50.54(w)(1) and 10 CFR 140.11," dated December 17, 1996 (ADAMS Accession No. ML15062A483), the staff recommended changes to the power reactor financial protection regulations that would allow licensees to lower onsite insurance levels to $50 million upon demonstration that the fuel stored in the SFP can be air-cooled. In its Staff Requirements Memorandum to SECY-96-256, dated January 28, 1997 (ADAMS Accession No. ML15062A454), the Commission supported the staff's recommendation that, among other things, would allow permanently shutdown power reactor licensees to reduce commercial onsite property damage insurance coverage to $50 million when the licensee was able to demonstrate the technical criterion that the spent fuel could be air-cooled if the spent fuel pool was drained of water. The staff has used this technical criterion to grant similar exemptions to other decommissioning

reactors (e.g., Maine Yankee Atomic Power Station, published in the *Federal Register* on January 19, 1999 (64 FR 2920); and Zion Nuclear Power Station, published in the *Federal Register* on December 28, 1999 (64 FR 72700)). These prior exemptions were based on these licensees demonstrating that the SFP could be air-cooled, consistent with the technical criterion discussed above.

In SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning," dated June 28, 2000, and SECY-01-0100, "Policy Issues Related to Safeguards, Insurance, and Emergency Preparedness Regulations at Decommissioning Nuclear Power Plants Storing Fuel in the Spent Fuel Pool," dated June 4, 2001 (ADAMS Accession Nos. ML003721626 and ML011450420, respectively), the NRC staff discussed additional information concerning SFP zirconium fire risks at decommissioning reactors and associated implications for onsite property damage insurance. Providing an analysis of when the spent fuel stored in the SFP is capable of air-cooling is one measure that can be used to demonstrate that the probability of a zirconium fire is exceedingly low. However, the staff has more recently used an additional analysis that bounds an incomplete drain down of the SFP water, or some other catastrophic event (such as a complete drainage of the SFP with rearrangement of spent fuel rack geometry and/or the addition of rubble to the SFP). The analysis postulates that decay heat transfer from the spent fuel via conduction, convection, or radiation would be impeded. This analysis is often referred to as an adiabatic heatup.

The licensee's analyses referenced in its exemption request demonstrates that under conditions where the SFP water inventory has drained completely and only air-cooling of the stored irradiated fuel is available, there is reasonable assurance that after August 2014, the SONGS spent fuel will remain at temperatures far below those associated with a significant radiological release. However, a portion of the air-cooling

analyses credits operation of the normal fuel building ventilation systems because the fuel building structures are robust and offer little potential for natural air exchange with the environment for cooling. Because the normal fuel building ventilation could become unavailable during an initiating event that would lead to complete SFP drainage (i.e., a seismic event), the NRC staff also relied upon the additional time that the fuel in the SONGS SFPs has had to cool since the plant was permanently shutdown in June 2013 during its evaluation of the licensee's exemption request. As discussed in the staff response to a question in SECY-00-0145, "the staff believes that full insurance coverage must be maintained for 5 years or until a licensee can show by analysis that its spent fuel pool is no longer vulnerable to such [a zirconium] fire."

Although the official certifications for permanent cessation of power operations and permanent removal of fuel from the reactor vessel were not submitted until June 2013, the staff notes that SONGS was in an extended outage to address steam generator issues, and neither SONGS, Units 2 nor 3, have produced power since January 2012. This additional storage time for the fuel in the SONGS SFPs has allowed it to cool for greater than the 5 years suggested in SECY-00-0145, which supports the conclusion that zirconium fire risks from the irradiated fuel stored in the SFPs is of negligible concern and exemption from the requested requirements is warranted.

In addition to the air-cooling scenario, the licensee's adiabatic heat-up analyses demonstrate that as of October 12, 2014, there would be at least 17 hours after the loss of all means of cooling (both air and/or water), before the spent fuel cladding would reach a temperature where the potential for a significant offsite radiological release could occur. The licensee states that for this loss of all cooling scenario, 10 hours is sufficient

time for personnel to respond with additional resources, equipment, and capability to restore cooling to the SFPs, even after a non-credible, catastrophic event.

As provided in SCE's letters dated October 7 and December 15, 2014, the licensee furnished information concerning its makeup strategies, in the event of a loss of SFP coolant inventory. The multiple strategies for providing makeup to the SFPs include: using existing plant systems for inventory makeup; an internal strategy that relies on installed fire water pumps and service water or fire water storage tanks; or an external strategy that uses portable pumps to initiate makeup flow into the SFPs through a seismic standpipe and standard fire hoses routed to the SFPs or to a spray nozzle. These strategies will be maintained by a license condition until such time as all fuel has been moved to dry storage in an onsite ISFSI. The licensee states that the equipment needed to perform these actions are located onsite, and that the external makeup strategy (using portable pumps) is capable of being deployed within 2 hours. The licensee also stated that, considering the very low-probability of beyond design-basis accidents affecting the SFPs, these diverse strategies provide defense-in-depth and time to mitigate and prevent a zirconium fire, using makeup or spray into the SFPs before the onset of zirconium cladding rapid oxidation.

In the safety evaluation of the licensee's request for exemptions from certain emergency planning requirements dated June 4, 2015 (ADAMS Accession No. ML15082A204), the NRC staff assessed the SCE accident analyses associated with the radiological risks from a zirconium fire at the permanently shutdown and defueled SONGS site. The NRC staff has confirmed that under conditions where cooling air flow can develop, suitably conservative calculations indicate that by the end of August 2014, the fuel would remain at temperatures where the cladding would be undamaged for an unlimited period. The staff also finds that the additional cooling time provided

for the fuel between January 2012 and the issuance of this exemption provides reasonable assurance that zirconium fire risks from the irradiated fuel stored in the SFPs is of negligible concern. For the very unlikely beyond design-basis accident scenario, where the SFP coolant inventory is lost in such a manner that all methods of heat removal from the spent fuel are no longer available, there will be a minimum of 10 hours from the initiation of the accident until the cladding reaches a temperature where offsite radiological release might occur. The staff finds that 10 hours is sufficient time to support deployment of mitigation equipment, consistent with plant conditions, to prevent the zirconium cladding from reaching a point of rapid oxidation.

The staff's basis as to why it considers $50 million to be an adequate level of onsite property damage insurance for a decommissioning reactor, once the spent fuel in the SFP is no longer susceptible to a zirconium fire, is provided in SECY-96-256. The staff has postulated that there is still a potential for other radiological incidents at a decommissioning reactor that could result in significant onsite contamination besides a zirconium fire. In SECY-96-256, the NRC staff cited the rupture of a large (~450,000 gallon) liquid radioactive waste storage tank containing slightly radioactive water, causing soil contamination and potential groundwater contamination, as the most costly postulated event to decontaminate and remediate (other than a SFP zirconium fire). The postulated large liquid radwaste storage tank rupture event was determined to have a bounding onsite cleanup cost of approximately $50 million.

The NRC staff has determined that the licensee's proposed reduction in onsite property damage insurance coverage to a level of $50 million is consistent with SECY-96-256 and subsequent insurance considerations, resulting from additional zirconium fire risks, as discussed in SECY-00-0145 and SECY-01-0100. In addition, the NRC staff notes that similar exemptions have been granted to other permanently shutdown and

defueled power reactors, upon demonstration that the criterion of the zirconium fire risks from the irradiated fuel stored in the SFP is of negligible concern. As previously stated, the staff concluded that as of October 12, 2014, sufficient irradiated fuel decay time has elapsed at SONGS to decrease the probability of an onsite radiological release from a postulated zirconium fire accident to negligible levels. In addition, the licensee's proposal to reduce onsite insurance to a level of $50 million is consistent with the maximum estimated cleanup costs for the recovery from the rupture of a large liquid radwaste storage tank. Finally, the staff notes that in accordance with the SONGS PSDAR, all spent fuel will be removed from the SFPs and moved into dry storage at an onsite independent spent fuel storage installation (ISFSI) by the end of 2019, and the probability of an initiating event that would threaten pool integrity occurring before that time is extremely low, which further supports the conclusion that the zirconium fire risk is negligible.

The Exemption is Authorized by Law

In accordance with 10 CFR 50.12, the Commission may grant exemptions from the regulations in 10 CFR part 50 as the Commission determines are authorized by law. The NRC staff has determined that granting the licensee's proposed exemption will not result in a violation of the Atomic Energy Act of 1954, Section 170, as amended, other laws, or the Commission's regulations, which require licensees to maintain adequate financial protection. Therefore, the proposed exemption for SONGS from the onsite property damage insurance requirements of 10 CFR 50.54(w)(1) is authorized by law.

The Exemption Will Not Present an Undue Risk to Public Health and Safety

The onsite property damage insurance requirements of 10 CFR 50.54(w)(1) were established to provide financial assurance that following a significant nuclear incident,

onsite conditions could be stabilized and the site decontaminated. The requirements of 10 CFR 50.54(w)(1) and the existing level of onsite insurance coverage for SONGS are predicated on the assumption that the reactor is operating. However, SONGS is a permanently shutdown and defueled facility. The permanently defueled status of the facility has resulted in a significant reduction in the number and severity of potential accidents, and correspondingly, a significant reduction in the potential for and severity of onsite property damage. The proposed reduction in the amount of onsite insurance coverage does not impact the probability or consequences of potential accidents. The proposed level of insurance coverage is commensurate with the reduced risk and reduced cost consequences of potential nuclear accidents at SONGS. Therefore, the NRC staff concludes that granting the requested exemption will not present an undue risk to the health and safety of the public.

The Exemption is Consistent with the Common Defense and Security

The proposed exemption would not eliminate any requirements associated with physical protection of the site and would not adversely affect SCE's ability to physically secure the site or protect special nuclear material. Physical security measures at SONGS are not affected by the requested exemption. Therefore, the proposed exemption is consistent with the common defense and security.

Special Circumstances

Under 10 CFR 50.12(a)(2)(ii), special circumstances are present if the application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule. The underlying purpose of 10 CFR 50.54(w)(1) is to provide reasonable assurance that adequate funds will be available to stabilize conditions and cover onsite cleanup costs

associated with site decontamination, following an accident that results in the release of a significant amount of radiological material. Because SONGS is permanently shut down and defueled, it is no longer possible for the radiological consequences of design-basis accidents or other credible events at SONGS to exceed the limits of the EPA PAGs at the exclusion area boundary. The licensee has performed site-specific analyses of highly unlikely, beyond-design-basis zirconium fire accidents involving the stored irradiated fuel in the SFPs. The analyses show that after October 12, 2014, the probabilities of such an accident are minimal. The NRC staff's evaluation of the licensee's analyses confirm this conclusion.

The NRC staff also finds that the licensee's proposed $50 million level of onsite insurance is consistent with the bounding cleanup and decontamination cost, as discussed in SECY-96-256, to account for hypothetical rupture of a large liquid radwaste tank at the SONGS site, should such an event occur. The staff notes that the SONGS technical specifications provide controls for unprotected outdoor liquid storage tanks to limit the quantity of radioactivity contained in these tanks, in the event of an uncontrolled release of the contents of these tanks. Therefore, the staff concludes that the application of the current requirements in 10 CFR 50.54(w)(1) to maintain $1.06 billion in onsite insurance coverage is not necessary to achieve the underlying purpose of the rule for the permanently shutdown and defueled SONGS reactors.

Under 10 CFR 50.12(a)(2)(iii), special circumstances are present whenever compliance would result in undue hardship or other costs that are significantly in excess of those contemplated when the regulation was adopted, or that are significantly in excess of those incurred by others similarly situated. The NRC staff concludes that if the licensee was required to continue to maintain an onsite insurance level of $1.06 billion, the associated insurance premiums would be in excess of those necessary and

commensurate with the radiological contamination risks posed by the SONGS site now that it has entered decommissioning. In addition, such insurance levels would be significantly in excess of other decommissioning reactor facilities that have been granted similar exemptions by the NRC.

The NRC staff finds that compliance with the existing rule would result in an undue hardship or other costs that are significantly in excess of those contemplated when the regulation was adopted and are significantly in excess of those incurred by others similarly situated. Therefore, the special circumstances required by 10 CFR 50.12(a)(2)(ii) and 10 CFR 50.12(a)(2)(iii) exist for the proposed exemption from the onsite property damage insurance requirements of 10 CFR 50.54(w)(1).

Environmental Considerations

The NRC approval of an exemption to insurance or indemnity requirements belongs to a category of actions that the Commission, by rule or regulation, has declared to be a categorical exclusion, after first finding that the category of actions does not individually or cumulatively have a significant effect on the human environment. Specifically, the exemption is categorically excluded from further analysis under 10 CFR 51.22(c)(25). Pursuant to 10 CFR 51.22(c)(25), the granting of an exemption from the requirements of any regulation in Chapter I of 10 CFR is a categorical exclusion provided that (i) there is no significant hazards consideration; (ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite; (iii) there is no significant increase in individual or cumulative public or occupational radiation exposure; (iv) there is no significant construction impact; (v) there is no significant increase in the potential for or consequences from radiological

accidents; and (vi) the requirements from which an exemption is sought are among those identified in 10 CFR 51.22(c)(25)(vi).

The NRC staff has determined that approval of the exemption request involves no significant hazards consideration because reducing the licensee's onsite property damage insurance at the decommissioning San Onofre Nuclear Generating Station, Units 1, 2, and 3, does not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. The exempted financial protection regulation is unrelated to the operation of SONGS.

Accordingly, there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite, and no significant increase in individual or cumulative public or occupational radiation exposure. The exempted regulation is not associated with construction, so there is no significant construction impact. The exempted regulation does not concern the source term (i.e., potential amount of radiation involved an accident) or accident mitigation; therefore, there is no significant increase in the potential for, or consequences from, a radiological accident. In addition, there would be no significant impacts to biota, water resources, historic properties, cultural resources, or socioeconomic conditions in the region. The requirement for onsite property damage insurance may be viewed as involving surety, insurance, or indemnity matters in accordance with 10 CFR 51.22(c)(25)(vi).

Therefore, pursuant to 10 CFR 51.22(b) and 10 CFR 51.22(c)(25), no environmental impact statement or environmental assessment need be prepared in connection with the approval of this exemption request.

IV. Conclusions

Accordingly, the Commission has determined that, pursuant to 10 CFR 50.12(a), the exemption from 10 CFR 50.54(w)(1) is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security. In addition, special circumstances are present. Therefore, the Commission hereby grants SCE an exemption from the requirements of 10 CFR 50.54(w)(1), to permit the licensee to reduce its onsite property damage insurance to a level of $50 million.

This exemption is effective upon issuance.

Dated at Rockville, Maryland, this 5th day of January, 2018.

For the Nuclear Regulatory Commission.

/RA/

Gregory Suber, Deputy Division Director,
Division of Decommissioning, Uranium Recovery
and Waste Programs,
Office of Nuclear Material Safety and Safeguards.

SUBJECT: EXEMPTION FROM THE REQUIREMENTS IN SECTION 54(w)(1) OF TITLE 10 OF THE *CODE OF FEDERAL REGULATIONS* (10 CFR), CONCERNING ONSITE PROPERTY DAMAGE INSURANCE (CAC NOS. L53097, L53098, AND L53099)

[DOCUMENT DATE] January 5, 2017 (FRN)

DISTRIBUTION: DCD R/F RBrowder, RIV RKellar, RIV

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EXHIBIT 12

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NRC Webinar
San Onofre Nuclear Generating Station Final Enforcement Action and Follow-up Inspection Preliminary Results

March 25, 2019

NRC Region IV, Arlington, TX

NRC Region IV Presenters

- Linda Howell, Deputy Director
  Division of Nuclear Materials Safety
- Lee Brookhart, Senior Inspector, Team Leader
  Fuel Cycle and Decommissioning Branch
  Division of Nuclear Materials Safety

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Agenda

Topic	Participants
Opening Remarks	Linda Howell
Final Enforcement Action	Linda Howell
NRC Follow up Inspection Activities	Lee Brookhart
Path Forward	Linda Howell
Questions and Answers/Discussion	All Webinar Participants Michael Bloodgood, Facilitator
Closing Remarks	Linda Howell

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- Only in the event of technical difficulties with the webinar, a telephone bridge line will be used:
  - Bridge Number: (800) 369-1771
  - Passcode: 7382934
  - Link to NRC Spotlight web page: https://www.nrc.gov/reactors/operating/ops-experience/songs-spec-insp-activities-cask-loading-misalignment.html

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Predecisional Enforcement Conference

- Held on January 24, 2019
- Discussed two apparent violations, safety significance, root causes, and corrective actions

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SIGNIFICANCE = "Severity Level"

SEVERITY LEVEL – I
(most significant regulatory concern)

SEVERITY LEVEL – II
(very significant regulatory concern)

SEVERITY LEVEL – III
(significant regulatory concern)

(Escalated Enforcement)

(Non-Escalated Enforcement)

SEVERITY LEVEL – IV
(less significant concern, but more than minor)

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Civil Penalty Assessment

- NRC Enforcement Policy Considers:
  - Enforcement history
  - Whether the licensee identified the issue
  - Adequacy of corrective actions

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Violation No. 1
Loss of Redundant Drop Protection Features

10 CFR 72.212(b)(3) requires, in part, that each cask used by the general licensee conforms to the terms, conditions, and specifications of a Certificate of Compliance. The spent fuel storage system's Certificate of Compliance requires that the canister be lifted and carried with redundant drop protection features to prevent uncontrolled lowering of the load.

Violation No. 1
Loss of Redundant Drop Protection Features

- S v rt/L v I Vi t
- $116,00 vi Pe y

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Violation No. 2
Failure to Make Required Notification to NRC

10 CFR 72.75(d)(1) requires, in part, that each licensee notify the NRC within 24 hours after the discovery of events involving spent fuel in which important to safety equipment is disabled or fails to function as designed when required to mitigate the consequences of an accident and redundant safety equipment is not available.

Violation No. 2
Failure to Make Required Notification to NRC

- Severity Level III Violation
- No Civil Penalty

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Licensee Response to NRC's Enforcement Action

Southern California Edison has three options:

- Accept the violations and pay civil penalty
- Deny the violation(s) or severity levels
- Protest civil penalty in whole or in part

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NRC Follow-up Inspection Activities

- To Determine If:
  - Root and contributing causes were understood
  - Extent of condition and extent of cause were identified
  - Corrective actions taken to preclude reoccurrence were effective

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Licensee Causal Evaluations

Four causal evaluations performed by Licensee:

- Root Cause for Downloading Incident
- Apparent Cause to Assess Licensee's Oversight
- Common Cause Evaluation
- Root Cause for Reportability

NRC determined that the evaluations were of adequate depth and breadth; however, two weaknesses were identified.

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Causal Evaluations Weaknesses

- Inadequate changes to Executive Oversight Board process
- Issues with Radiation Protection were not formally addressed in causal evaluations

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Corrective Actions

- **From the Four Cause Evaluations:**
  - Total of 71 Corrective Actions
  - Total of 9 Corrective Actions to Preclude Repetition
  - Total of 8 Effectiveness Reviews

- **NRC Assessment:**

The corrective actions were comprehensive to address and prevent reoccurrence; however, six corrective action weakness were identified.

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Corrective Actions

Subject Areas

- Procedures Changes
- Personnel Enhancements
- Equipment
- Training
- Corrective Action Program
- Demonstrations
- Reportability
- Special Inspection Follow-up Items

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Procedures

- **Licensee made changes to spent fuel handling procedures**
  - Critical steps with specific criteria
  - Clearly defined personnel roles, responsibilities, and qualifications
  - Load monitoring equipment enhancements
  - Additional required personnel during downloading

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Corrective Action Weaknesses

- Downloading Procedure
  - Lacked contingency steps for equipment failures
  - Incomplete criteria for suspending downloading operations
  - Incomplete steps to maintain seismic qualifications during cask transport from fuel building to the storage pad

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Personnel Enhancements

Previous Personnel on the Storage Pad

- Vertical Cask Transporter Operator
- Spotter in lift basket

Revised Personnel on the Storage Pad

- Vertical Cask Transporter Operator
- Vertical Cask Transporter Platform Rigger
- Rigger-in-Charge in lift basket
- 2nd Rigger in 2nd lift basket
- Cask Loading Supervisor
- Licensee Oversight Specialist
- Radiation Protection personnel
- Two Vertical Cask Transporter spotters
- Mating Device Operator

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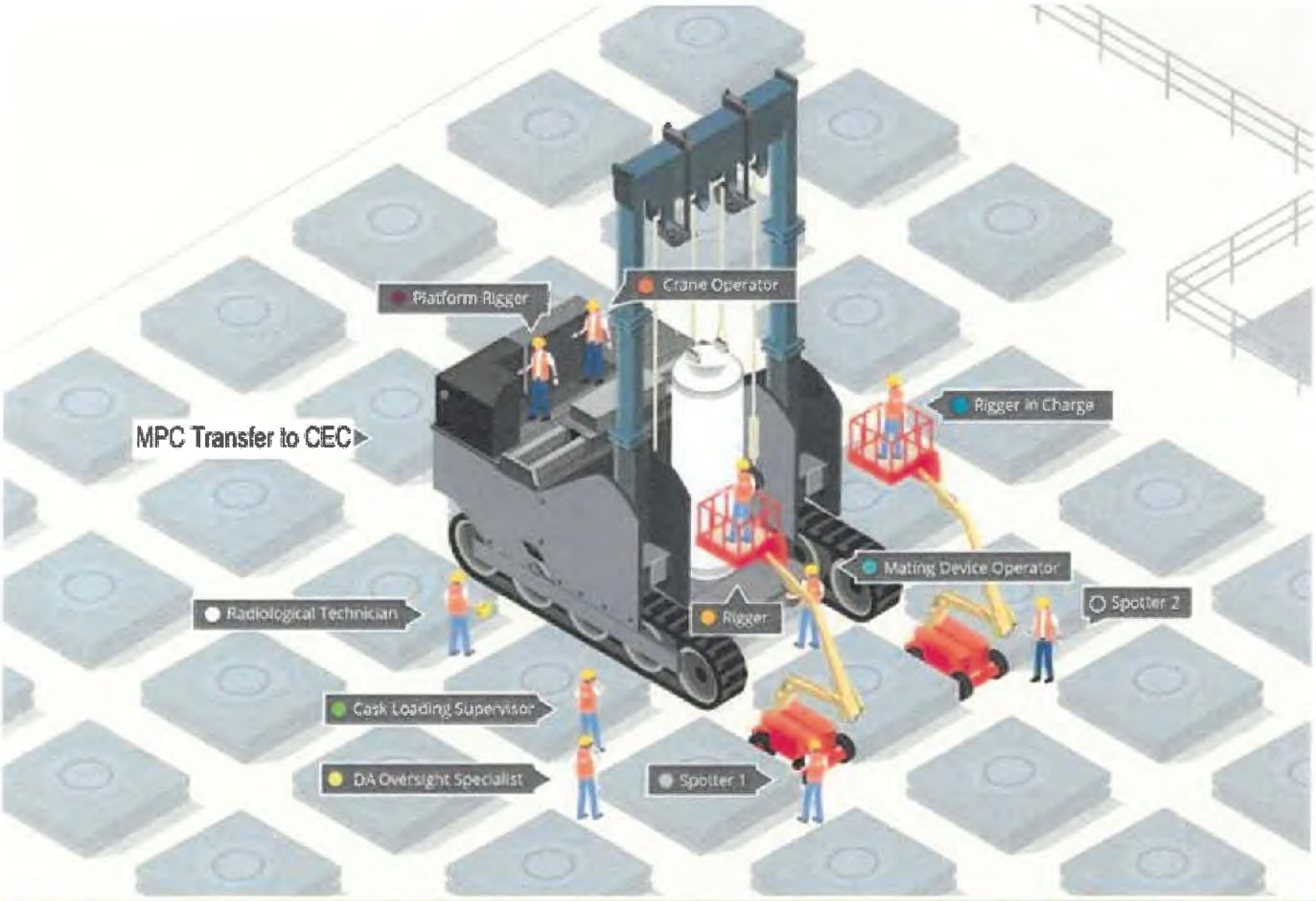

Revised Downloading Personnel

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Rigger-in-Charge &
2nd Qualified Rigger

22

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Load Indication Enhancements

Previous Mon t ri

- –
-

Revised Monitoring

-
-
-
-
-
-

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Load Information Displayed on Tablet

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Camera above Transfer Cask

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Corrective Action Weakness

- Improper classification of new equipment
  - Intermediate slings and devices
- Inadequate procurement of Important to Safety equipment
  - Load cell devices

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Training

- Developed SONGS specific spent fuel training programs and training procedures
- Revised training program for SONGS Oversight Specialists
- Revised Corrective Action Program training
- Developed event notification training

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Oversight

- Revised contractor oversight procedures
- Dedicated additional SONGS oversight personnel for contractors

NRC identified a weakness regarding maintenance procedure review

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Corrective Action Program

- Holtec project personnel work directly under SONGS Corrective Action Program
- Established a full-time Quality Assurance Manager Position
- Training conducted to emphasize use of a low-threshold for initiating corrective action process

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Demonstrations Observed by NRC

- Demonstrated moving transfer cask from fuel building to storage pad
  - HI-PORT operations
  - Vertical cask transporter operations
- Demonstrated simulator canister downloading
- Demonstrated simulator canister uploading
- Demonstrated revised fuel building lifting operations

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Transfer Cask on HI-PORT to Storage Pad

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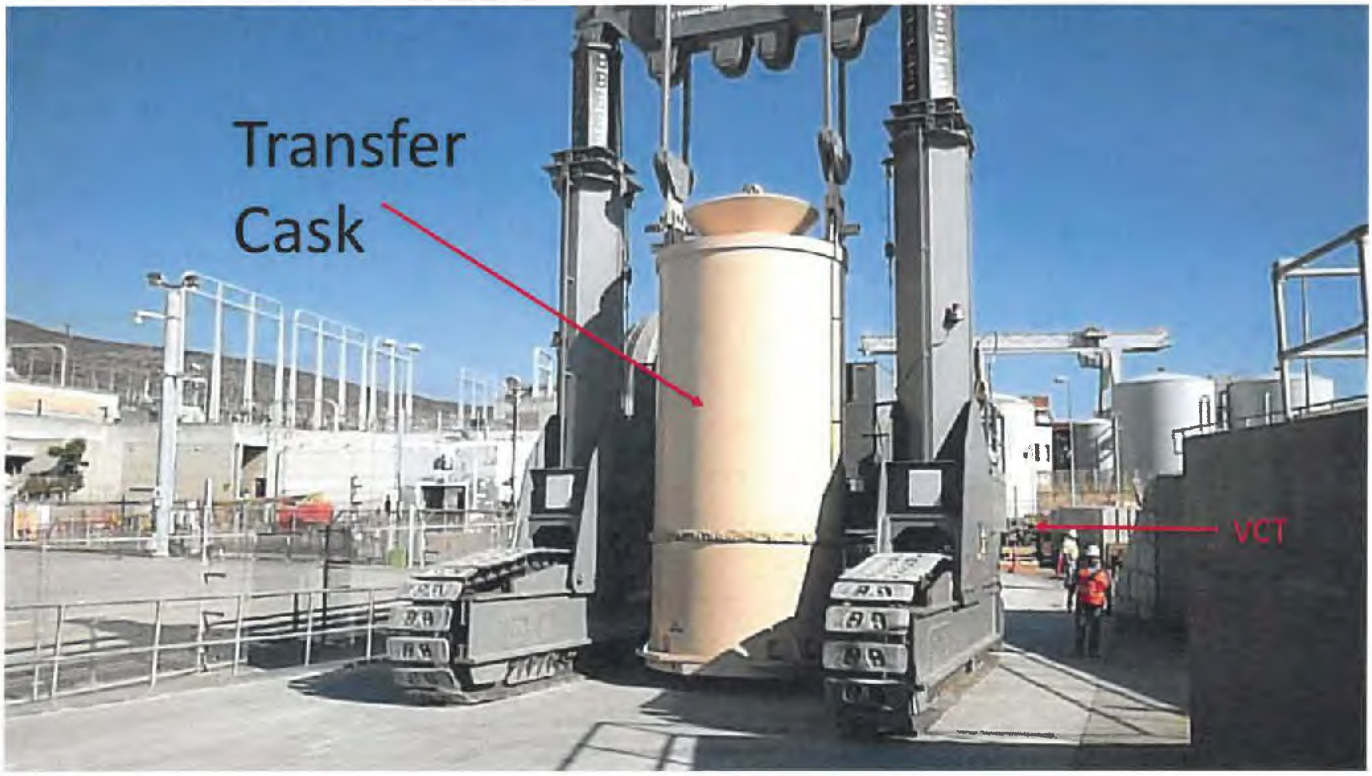
Vertical Cask Transporter Operations



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Downloading

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Fuel Building Operations

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Corrective Actions Weakness

- Removal of restraint band from HI-TRAC invalidated seismic analysis

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Reportability

- Revised Notification Procedure to have a conservative bias
- Developed Reportability Training for Managers and Regulatory Affairs personnel
  - Identify reportable events
  - Identify Important to Safety components
  - Identify potential failures or deviations that require NRC notification
- Biennial Refresher Training

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Special Inspection Follow-up Items

- Drop Evaluation
  - Canister integrity maintained
  - Fuel damage would likely occur
- Scratch Evaluation
  - Inadequate to support change to Final Safety Analysis Report
  - Several calculation errors

Path Forward

- Corrective actions implemented for causal factors and issues identified during Special Inspection
- Outstanding issue is the assessment of ongoing licensee analyses and process used to change the Final Safety Analysis Report (FSAR)
- Enhanced inspection oversight continues
- Licensee continues to suspend fuel loading operations until analysis is complete and NRC has reviewed the results

NRC Webinar
San Onofre Nuclear Generating Station

BREAK IN SESSION
RETURNING SHORTLY

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Questions and Comments

Facilitator: Michael Bloodgood

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U.S.NRC
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CONCLUSION OF WEBINAR

EXHIBIT 13

WEBINAR TRANSCRIPT

This document provides the transcript from a public meeting (webinar) that was held on November 8, 2018, to discuss preliminary observations of an NRC special inspection that was conducted at San Onofre Nuclear Generating Station in September 2018. The inspection was conducted in response to a situation that resulted in the misalignment of a multi-purpose canister loaded with spent fuel at the San Onofre Nuclear Generating Station.

Hosts of Webinar:

Troy Pruett, Director
Division of Nuclear Materials Safety
Region IV

Patricia Silva, Chief
Inspection and Operations Branch
Division of Spent Fuel Management
Office of Nuclear Material Safety and Safeguards

Eric Simpson, Health Physicist
Fuel Cycle and Decommissioning Branch
Division of Nuclear Materials Safety
Region IV

- This is Troy Pruett, with the NRC
in Region IV, and we're going to commence today's webinar
on the results of the San Onofre special inspection.
Thank you for joining the webinar.
NRC speakers will present information related
to the August 3rd, 2018 misalignment
of a multi-purpose canister loaded with spent fuel
at the San Onofre Nuclear Generating Station.
This is the NRC Region IV's first use
of the webinar format to provide information
to the public on a special inspection.
There's are pros and cons
for conducting a webinar public meeting
in place of a face to face meeting.
Ultimately, we decided that the large number
of people from across the United States
that were interested in learning more
about this event made the webinar the best option.
During the webinar, we will present information
explaining photographs and bullets shown on the slides.
The photos we are referencing today are
from downloading operations that occurred prior
to the August 3rd event.
The slides are also available from the webinar handout tab,
as well as the NRC Spotlight Section
on the NRC public webpage at www
.NRC.gov.
From the Spotlight Section, click
on SONGS Cask Loading Issue, and from there,
you'll see a variety of documents available for your review,
today's slides being one of the options.
During the presentation, you may submit written comments

and questions via the webinar chatroom feature.
NRC staff will collect items, and refer them
to today's panel, the NRC panel will answer questions
and respond to comments as time allows.
The webinar is scheduled to end at 5:00 p.m. Central Time,
or 3:00 p.m., Pacific.
If, for some reason, the NRC loses internet connectivity,
we will dial into a telephone bridge line,
and continue the presentation.
The backup bridge line may be reached
by dialing 888-
469-
1677,
and the passcode is 247-
1451.
And again, we will only use this bridge line
if the internet connection
for the NRC fails during the webinar.
We are recording the session today,
and plan to make the video publicly available.
Today's NRC panel has three members,
myself, Troy Pruett, and I'm the Director
of Nuclear Materials Safety in Region IV.
The Region IV office is located in Arlington, Texas,
and my division oversees the inspection activities
at San Onofre.
Also on the panel is Eric Simpson.
Eric is the Special Inspection Team Leader
for the event we are presenting today.
Eric is also an inspector in NRC Region IV.
We also have Patty Silva, Patty is a Branch Chief

from the Division of Spent Fuel Management,
in our headquarters office in Rockville, Maryland.
Patty was also a member of the Special Inspection Team.
Patty joined the panel to provide responses
to some of the questions or comments you might have
that are beyond the scope of Eric's special inspection.
Supporting our presentation,
we have technical staff monitoring the chatroom
for questions and comments,
and communications staff monitoring
and adjusting the audio and video.
Via, our webinar capability will only host up
to 500 participants,
and my staff has communicated
to me that we have hit the 500 registered limit,
and so, just as a reminder, if you encounter somebody
that's not able to log in to the webinar today,
remind them that the presentation will be publicly available
after the meeting, once we get the recording transcribed,
and posted to the public webpage.
So Eric will provide most of the information
regarding the misalignment event at San Onofre.
Eric will begin with background information
on the independent spent fuel storage installation
at San Onofre, he will then provide an overview
of a typical downloading operation.
By downloading, I mean the operation
that lowers the multipurpose canister into the storage vault
at the independent spent fuel storage installation.
Eric will then cover what happened on August 3rd, 2018,
during the downloading operation.
After he explains the event,

Eric will outline the NRC's regulatory concerns,
and our next steps.
While the misalignment event at San Onofre is serious,
at no time was there an actual load drop,
and at no time was there a release
of radioactive material from the multipurpose canister.
Once Eric has completed his presentation,
the NRC panel will begin responding
to questions and comments, when multiple questions
and comments on a similar topic are received,
the NRC staff monitoring the chatroom will provide
the panel a representative question or comment.
I'll now turn the presentation over to Eric.
- Good afternoon, I am Eric Simpson,
a Dry Fuel Storage Inspector of the NRC Region IV office,
here in Arlington, Texas.
Before we discuss the August 3rd event at San Onofre,
I would like to acknowledge the other members
of the NRC Special Inspection Team
that are not sitting on the panel with us today,
those members being Marlon Davis, NRC Headquarters Inspector
for the Division of Spent Fuel Management,
Chris Smith, a Region IV Engineering Inspector,
my Branch Chief, Dr. Janine Katanic, and Mr. Lee Brookhart,
our Senior Dry Fuel Storage Inspector, who has been working
behind the scenes throughout our efforts.
Let's start with an overview of the
San Onofre Independent Spent Fuel Storage Installation.
You will hear me refer
to Independent Spent Fuel Storage Installations as ISFSIs
for short throughout this webinar.

What you see is an overhead schematic
of the San Onofre ISFSI, north is to the left,
which places the Transnuclear horizontal ISFSI
on the eastern side, and the Holtec UMAX ISFSI
on the west, or bottom of the map.
The design is a horizontal storage module.
San Onofre has 63 horizontal storage modules
on this eastern ISFSI pad, 51 of which are loaded
with spent fuel in Unit One reactor waste,
the other three are empty, to the west
of the horizontal ISFSI is the Holtec UMAX ISFSI,
spent fuel is stored in stainless steel canisters
called multipurpose canisters, or MPCs.
Today we will refer to the MPCs simply as a canister.
The canisters are stored vertically
in the UMAX ISFSI vault.
San Onofre has room for 75 canisters in its UMAX ISFSI.
San Onofre had about 2,668 spent fuel assemblies stored
in its unit two and three spent fuel pools.
Currently, about 40% of the spent fuel has been transferred
to the UMAX ISFSI.
This photo shows what it's like looking down
into a UMAX storage vault, what you see are the features
of the divider shell,
we will discuss this in more detail later,
but for now, make a note of the shield ring.
During the August 3rd event, a portion
of the canister was resting on the shield ring.
San Onofre personnel and Holtec contractors failed
to note the misalignment, and that the weight
of the canister was no longer being supported
by the important-to-safety lifting equipment.

This photo shows a Holtec canister.
Spent fuel is placed into a canister
while it is inside the transfer cask.
The transfer cask is then placed
to reduce radiation exposures to workers,
and it is also used to help move the loaded canister out
onto the ISFSI pad.
This photo shows a shield cone.
After loading, the canister of spent fuel contents are dried
and welded shut, the shield cone is installed
on the canister as an additional help
to reduce radiation dose to cask storage workers.
The green slings are for retrieval
of the shield cone after the canister has been lowered
into the storage vault.
The yellow slings are important-to-safety, and are intended
to hold the canister weight during downloading operations.
This photo shows the flat bed transporter
with a transfer cask meeting up
with the vertical cask transporter.
The transfer cask, with the canister inside,
is moved from the fuel building
to the ISFSI pad used in a flatbed transporter.
A vertical cask transporter is used
to move the transfer cask into position
on the ISFSI pad, the vertical cask transporter is also used
to align the transfer cask and the canister
for downloading operations.
This photo shows the mating device used
to connect the transfer cask to the ISFSI vault.
The mating device has a hydraulic door

to allow access from the transfer cask into the ISFSI vault.
As you can see, the mating device is open in this photo.
This photo shows the vertical cask transporter being aligned
to the mating device,
the vertical cask transporter is positioned
over the mating device, properly aligned,
and then they're bolted together.
The mating device door is closed during this process.
This picture shows the spotters,
those are the people in the lift baskets,
pulling the slings through the sheaths
on the vertical cask transporter crossbeam.
The important-to-safety yellow slings are connected
to the canister through lift cleats in the shield cone,
and anchored to the vertical cask transporter.
This photo shows the canister ready for downloading,
the vertical cask transporter lift beam has been raised,
and the full load
of the spent fuel canister is being suspended.
The mating device door is open,
allowing the canister to be downloaded into the ISFSI vault.
So, what exactly happened on August 3rd?
This slide shows a schematic of the ISFSI pad,
and the location of the low dose waiting area.
The slide also shows a photo of the view from that location,
as you can see from the photo to the right,
the low dose waiting area has an obstructed view
of what is happening out on the pad.
Before downloading, all oversight staff,
other than the spotter
and the vertical cask transporter operator, are moved
to the low dose area.

From this position, none of the management
or supervisory oversight staff from San Onofre
or Holtec could observe the downloading of the canister.
San Onofre oversight staff did not have radio headsets,
and did not monitor communications
between the cask loading supervisor, spotter,
and vertical cask transporter operator.
This slide shows photos of the vertical cask transporter,
and the control panel.
The vertical cask transporter operator attempted
to lower the canister into the vault
by lowering the vertical cask transporter lift beam.
The NRC identified numerous deficiencies involving
the operation of the vertical cask transporter.
First, the training program did not ensure
the vertical cask transporter operator was capable
of performing the canister download.
Second, the vertical cask transporter operator is seated
behind shielding, and cannot see the canister being lowered
into the vault, third, cameras are not used
to aid the vertical cask transporter operator,
or oversight staff during downloading operations.
Fourth, the vertical cask transporter operator
did not monitor data available
on the vertical cask transporter control panel
during the download.
As a result, the vertical cask transporter operator
did not identify a decrease in hydraulic pressure,
which in and of itself is an indication
of a loss of mode condition.
Fifth, procedures did not provide adequate instructions

for the monitoring
of critical parameters during the download.
Lastly, the August 3rd event was the first time
for the vertical cask transporter operator
to download a spent fuel canister into the vault,
and no supervisory oversight was available
on the vertical cask transporter.
This slide shows a spotter in position
to observe the download,
the spotter was the only person capable of observing
the canister being downloaded during this event.
NRC identified numerous deficiencies involving
the spotter positioning, first,
the training program did not ensure the spotter was capable
of performing a canister download.
Second, procedures did not provide adequate instruction
for monitoring of critical parameters
during download processes.
Third, the August 3rd event was the first time
for the spotter to download a spent fuel canister
into the ISFSI vault, and no supervisory oversight
was available in the lift basket.
Fourth, no cameras were provided for management
and supervisory oversight to observe the download.
Fifth, once the downloading was in progress,
the spotter moved the lift to the side,
where he could no longer directly observe
the canister's progress into the ISFSI vault, and lastly,
the spotter did not know how
to determine the important-to-safety slings for slack.
Communications during the download were informal,
and failed to relay critical information,

for example, during the download, the spotter communicated
that the canister was four feet down.
Management and supervisor incorrectly believed
this meant four feet below the mating device, it did not.
The VCT operator fully lowered
the vertical cask transporter crossbeam, and communicated
that the canister was fully loaded, lowered into the vault.
A radiation protection technician noticed
the dose rates were significantly higher than expected,
and alerted the cask loading supervisor.
Station personnel observed that the slings were slack,
and that the canister was not downloaded.
At the direction of the rigger in charge,
at the direction of the rigger in charge,
the vertical cask transporter operator raised the lift beam
to regain load of the canister.
The canister was properly aligned,
and then lowered into the ISFSI vault.
The canister load was unsupported by lifting equipment
for approximately 53 minutes.
This slide shows a photo of the installed canister
in the ISFSI vault.
Before starting downloads of lowered canisters,
San Onofre trains staff using test equipment.
The training canister was smaller
than the actual canisters used at San Onofre.
The training canister provided about three quarter
of an inch more clearance, this made the lining
and lowering the training canister much easier
than would be experienced
during actual downloading operations.

Staff conducting downloading operations were not trained
on the differences,
when training does not match the actual conditions,
we refer to this as negative training.
During downloading operations,
San Onofre frequently experienced the bottoms
of canisters getting caught on the shield ring.
San Onofre never identified the misalignments
as conditions adverse to quality, consequently,
San Onofre never implemented actions
that would have prevented the August 3rd event.
On August 3rd, the canister made contact,
and rested on the shield ring, if you look closely
at the picture, you can see contact surface wear,
paint scrape, but no deformation of the shield ring.
San Onofre has not inspected the bottom of the canister,
their preliminary analysis indicates negligible wear
on the canister.
The NRC will evaluate San Onofre's analyses,
and San Onofre's plan to monitor the canisters,
as part of their Aging Management Program, when completed.
The NRC does not believe there is
an immediate canister integrity concern, so,
what's been done since August 3rd?
We'll look at San Onofre's activities since August 3rd,
then we'll look at NRC's actions.
We will discuss San Onofre's notification
to the NRC Operation Center, we'll briefly touch
on San Onofre's causal evaluations, and lastly,
we'll touch on San Onofre's proposed corrective actions.
The canister involved
in the August 3rd event was successfully lowered

into the UMAX ISFSI vault, we call this canister MPC 29
because it was the 29th canister loaded at San Onofre.
After MPC 29 was lowered into the ISFSI vault,
San Onofre immediately put a halt
to all spent fuel activities on site.
There was a spent fuel canister
that was being processed in a Unit Two Fuel Building,
that canister was fully processed, meaning it was dried,
helium back-fill operations were completed,
final welding of the closure rings were performed,
and it is currently in the Unit Three Fuel Building.
It is seismically restrained, it is placed
in a transfer cask, and this is a condition
that is acceptable for the canister,
and its spent fuel contents.
NRC's involvement, we were notified of the August 3rd event
on the afternoon of August 6th.
We then initiated daily oversight communications
between San Onofre, NRC headquarters,
and ourselves in the regional office.
On August 7th, San Onofre committed to an NRC review,
before resuming dry cask loading operations.
On August 17th, we decided to conduct a special inspection.
If you go to the Spotlight Section of the NRC website,
our charter is available for review there.
We arrived at San Onofre to initiate our special inspection
on September 10th, we were onsite the entire week,
reviewing procedures, records,
and talking with former and current employees.
The inspection continued offsite until we formally exited
with San Onofre on this past Thursday, November 1st,

which brings us to our findings.
We have two preliminary violations
that are being considered for escalated enforcement,
those being a preliminary violation
for the event itself, San Onofre's license requires
that during downloading operations, the canister, MPC,
be handled with redundant drop protection features
to prevent uncontrolled lowering of the load.
Contrary to the requirement, during MPC transfer,
when loaded with spent fuel, the licensee failed to ensure
the lifting equipment had redundant drop protection features
to prevent uncontrolled lowering.
Specifically, San Onofre inadvertently disabled
the important-to-safety downloaded slings,
when personnel lowered
the vertical cask transporter crossbeam
to the fully seated position, while the MPC was suspended
by the shield ring, approximately 18 feet
above the fully seated position in the vault.
The second preliminary violation being considered
for escalated enforcement is the notification requirement.
10CFR
72.75(d)(1)
requires
that a licensee notify the NRC
within 24 hours when important-to-safety equipment
is disabled, or fails to function as designed.
Contrary to the requirement, San Onofre failed
to make proper NRC notification
of the August 3rd event to the NRC Operation Center,
until September 14th, they were prompted by us
to make the required notification during our inspection.

We are also considering three preliminary violations
of lesser severity level to San Onofre,
a violation for inadequate procedures, a violation
for failing to acknowledge conditions adverse to quality
for entry into the site's corrective action program,
and a violation for inadequate training
of personnel operating important-to-safety equipment.
It is important to note
that management oversight weaknesses contributed to each
of the preliminary violations being considered by NRC.
Southern California Edison
and Holtec have both performed causal evaluations related
to the August 3rd event.
Preliminary root and apparent causes are lack
of adequate procedures, lack of adequate training
to support the procedures, lack
of adequate licensee oversight of contractor activities.
Some of the preliminary corrective actions
at San Onofre revolve around enhancing
the training requirements, procedure enhancements,
and equipment enhancements to give more positive indication
of a loss of load condition.
San Onofre is also looking at improving its performance
in the oversight role.
NRC will perform an inspection at San Onofre
to fully assess its corrective actions,
prior to them resuming fuel handling operations.
A word or two about the event, and its significance.
San Onofre was not required to have a drop analysis
for this type of event because the license required
redundant drop protection features at all times.

That's why this misalignment event is so very significant.
San Onofre provided preliminary analysis
of a canister drop from 19 feet into the vault,
that analysis is still under review by NRC experts.
The San Onofre analysis document
that the canister must still maintain confinement,
and that no breach would occur, however,
the analysis does describe that some fuel assemblies
would likely fail, due to the drop.
However, the San Onofre preliminary analysis describes
that the canister would still be able to perform safely,
it would still meet all thermal, pressure,
criticality, and confinement criteria.
This part of the analysis is still under review.
NRC plans to issue its special inspection report
before the Thanksgiving holiday.
Next steps involve dispositioning
the escalated enforcement findings,
which means moving through the NRC enforcement process,
along with San Onofre,
to disposition with preliminary violations
and severity levels to be assigned.
The timing of that process begins
once we issue the inspection report.
Having moved through the events of August 3rd,
and having discussed NRC and San Onofre's next steps,
I'll hand the presentation back over to Mr. Troy Pruett.
- Thank you, Eric, I'm going to,
I'm going to pause for just a second, and,
and ask a couple of questions to you.
- Okay.
- That, that we've been receiving through the chatroom.

- All right.
- One of the questions involves redundant drop protection,
and so what was the redundant drop protection?
- Okay, as I mentioned earlier in the presentation,
I pointed out two yellow slings,
each of those slings can fully support the weight
of a loaded canister, that is to say,
the weight of a loaded MPC, and since there are two slings,
that counts as redundant drop protection.
Again, they can both completely support the weight
of the loaded MPC, if one fails,
the other one is there to provide that redundant protection.
- Right, so Rachel, could you pull up slide 10?
- There we are.
- Right, so slide 10 is the picture
of the shield cone, and as Eric mentioned earlier,
there's a photo there showing the two yellow slings,
that is the redundant drop protection, so.
- Yes, and the event revolves
around inadvertently disabling both of those slings
by having the crossbeam in the fully lowered position,
while those slings were completely slack.
If there had been, in the event of a drop,
those slings would have been rendered completely incapable
of stopping that drop.
- And then there were another set of questions, was,
just, just how much does one of these canisters weigh?
- Well, they're analyzed to weigh up to 113,000 pounds,
but I think the MPC in question was roughly
around 100,000 pounds, so 50 tons.
- Okay, and then, and then

about how many fuel assemblies does the canister hold?

- Each fuel, each MPC 37, as named,

will hold 37 spent fuel assemblies.

- Okay, thank you, so I'm going to,

I'm going to conclude the, our meeting presentation,

and then we still have some more questions that my staff

that's monitoring the chatroom is sending me,

and we'll jump into the questions in just a minute, so.

So I bet the take aways are,

this event could have been prevented

with effective management and supervisory oversight

of important-to-safety operations performed at San Onofre.

Management oversight weaknesses led

to inadequate training of the staff,

the failure to provide appropriate procedures,

not identifying and correcting conditions adverse

to quality, and not providing appropriate supervision

at job sites, these deficiencies converged

on August the 3rd, resulting in a failure

to provide redundant load drop protection,

during the downloading of a spent fuel canister.

As a result, the NRC has increased the regulatory oversight

at the facility to ensure that the root

and contributing causes are understood,

and that the corrective actions will prevent another loss

of load event, so with that,

that's going to wrap up our formal part of the presentation,

and we're going to transition into responding

to the questions and the comments

that we're receiving in the chatroom.

So one of the,

or many of the questions

and comments involve the retrievability of a canister.
And I know, Patty, this was something we talked
about yesterday, would you like to touch on what the,
is a licensee required to be able to retrieve a canister,
and maybe Eric, you can jump in if you,
if you hear something that needs to be said.
- Well, if you like, I can start off
on this, and-- - Okay, all right.
Fair enough. - Well, 10CFR72
.122(l)
requires that storage systems must be designed
to allow ready retrieval of spent fuel,
high level waste, and reactor related grade
and class C waste for further processing of disposal,
and each licensee must demonstrate the ability
to retrieve a canister, for taking back
into the spent fuel pool, if it's available.
And licensees are also required to demonstrate the ability
to cut open a canister to allow them access
to the spent fuel contents inside.
Now, saying this, I will tell you all that each licensee,
generally, does not have to display the ability
to cut open a canister, we allow for the vendor
to demonstrate the ability to cut
that canister open at their facility, the belief being
that if the licensee ends up in the position
where they have to retrieve a canister,
and take it back into their spent fuel pool,
the vendor can provide them
with the equipment to cut that canister open.
And Holtec has demonstrated

that they can cut open an MPC 37, or an MPC 89 canister,
which are other types of canisters
that are licensed for storage in the UMAX vault.
- And then, and then, Eric, I'm going to send this question
to you, as well. - Okay.
- Was there actual damage to the canister in question?
- We don't believe there was damage
to the canister in question, or at least not to the extent
that its safety features are being disabled, however,
we think that the Aging Management process will be able
to go in and inspect these canisters
because San Onofre is part of the Aging Management,
we will be inspecting the canisters for degradation,
beginning within five years.
- And what, if this canister really dropped,
as a result of this misalignment event,
what do you perceive the consequences would have been?
- Well, as it stands now,
we do not believe the canister would have been breached.
It would have ended up being a question of the contents.
If the contents were designated as undamaged fuel,
certainly everybody who's been looking
at these drop analyses pretty much concedes
that the fuel inside the canister will no longer meet
the criteria of undamaged fuel.
It would end up being a question as to whether we,
they want a license amendment to allow them
to remain in the stored position,
and damaged fuel, or whether or not we would be asking them
to retrieve the canister to remove the spent fuel contents,
to repackaging in a damaged fuel canister.
- Okay.

And isn't, isn't the August 3rd event exactly
the same as the event that happened in July?
- It is not, the event that happened in July,
one of the reasons I think that it did not make its way
into the corrective action program is
because I think that they believed
that during that entire extended time it took them
to download the MPC into the UMAX vault,
for the record, there was an event on July 22nd, where
San Onofre experienced an abnormal delay
in downloading operations, what should have
taken 15 minutes ended up taking an hour and a half
because they failed to get the MPC properly aligned
for downloading for over an hour and a half.
Again, this should have taken place
in 15 minutes or less, during that time,
never was the MPC, or the canister,
not suspended by the slings, every time they attempted
to download, they caught the loss of load condition.
The VCT operator actually caught the loss
of load condition using his monitoring devices
on the vertical cask transporter screen, something
that did not happen on August 3rd, where the VCT operator
was not monitoring these proper parameters
on his vertical cask transporter screen.
So they were always within procedure during this event.
We feel, however, that the event being captured
in what was known as a production traveler,
it should have also been recorded,
and it's part of their corrective action program.
So at no point were the redundant safety features

completely disabled for the July 22nd event,
and they were always in procedure during that event.
- So perhaps you can clarify what we mean by disabled.
So the slings, I mean, the slings were always okay.
- The slings were always okay.
- So what do you mean by a disabled sling?
- What I mean by disabled sling, well,
I wish I had a picture, that you guys could look at it.
Well, if you refer to the picture
that's being displayed on the webinar right now,
you see the MPC is being suspended
by two yellow slings, now,
when those slings are no longer supporting the load,
it's called a slack condition, to use the parlance
of the Holtec procedures.
During the downloading event of July 22nd,
they never completely lost the load from the slings.
- Just a second, Rachel, let's try slide 16.
- Yeah, there we go, so the slings were always supported
in the load for July 22nd event.
Contrasting that event, we don't actually have a picture
of what happened on August 3rd,
but if you can visualize with me,
on August 3rd, the crossbeam that you see
in that picture there was all the way down
in the completely lowered position,
and the slings on either side of that high track canister,
they were completely bunched up on the ground,
supporting no load whatsoever.
And at that time, that MPC was resting
on the shield ring on top of the divider shell inside
of the ISFSI vault.

If that MPC had slipped, or the canister had slipped somehow
because of vibration, or some other mechanism during
that time, those slings, in the completely slack
and bunched up position, were in no condition
to capture and arrest that drop.
That MPC would have dropped to the bottom
of that canister with no slings being enabled
to suspend the load.
That's really what I mean by the July 22nd event.
On the July 22nd event,
the slings were never rendered completely disabled.
- Okay, thank you for that clarification.
And then, earlier you had talked
about a Aging Management, the Aging Management Program.
Patty, is that something you want to talk to?
- Sure. - Okay.
- So Aging Management Program is required upon 20 years,
upon the 20 year license renewal of the storage system.
The licensee's Aging Management Program requires
it will inspect during the, requirements will be inspected
during NRC's routine inspections.
Some licensees have performed in-service inspections
of their canisters as part
of the license renewal applications,
also the Electric Power Research Institute studies
on methods for inspecting,
and through implementing Aging Management Programs.
No breaches of canisters have been identified,
no chlorine induced stress corrosion cracking
has been identified.
So that's the Aging Management Program.

- For, oh, when you, might have, no indications
of cracking have been identified,
that's during the non-destructive exams at other facilities?
- Correct, that's, they usually use
what they call a crawler with a camera, usually,
or other NDE, non-destructive evaluation equipment.
- Okay, thank you for that,
and I think you heard Eric mention earlier that San Onofre
is a little bit different than the rest of the industry.
So other utilities have
to initiate an Aging Management Plan, as part
of license renewal for the ISFSI, which occurs at year 20.
San Onofre actually has an agreement
with the California Coastal Commission,
and they're actually required
to submit their Aging Management Plan for review
by the state, I think it's by 20--
- November, 2020. - November of 2020.
So that's an important distinction at San Onofre.
And then, just to clarify, for the August 3rd event,
there was no damage to any of the fuel assemblies
and the canister,
and there was no damage to the canister itself.
And then we, and we have also had several questions
regarding the drop analysis, and so,
just to clarify one more time what Eric said,
San Onofre was not required by their license
to have a drop analysis
for this condition
that existed on August 3rd, so they're not required
to analyze for 18 foot drop of a canister.
And the reason for that is, is that their license requires

that they provide redundant drop protection
throughout the movement of a canister.
And that's what makes this event so serious, is that,
is that not only did they lose one method
of drop protection, they lost all methods
of drop protection,
so that's what makes this event so serious.
The corrective actions coming out of this will be to,
to beef up the controls at the site to ensure
that they don't lose redundant drop protection
in the future,
and Eric touched on a few of those earlier,
but there are many procedural enhancements
that are taking place, there's additional training,
the workforce that's taking place,
the standards for job site presence by supervisors
and managers and quality assurance are all being revised,
and then there's actually some engineering changes.
- Yep. - That are being considered.
I think there's a possible addition
of a load cell indicator. - Correct.
- And I think there's a couple of more.
- Oh, yeah, they're talking about having alarms
in place when a certain loss of load condition is met,
an unambiguous alarm that will let everyone know
that you need to come back up on the beam
to regain load, they also have cameras
that they're investigating using to assist in the process.
And there's some even somewhat lower tech methods
they're using to make sure, but they are putting
in place procedure enhancements and equipment enhancements

to sort of ensure that they never end up
in this situation again.
- All right, and still more clarifications
on the drop analysis, so when we said,
I think you said, clearly the fuel inside the canister
would no longer meet the undamaged criteria,
but, so, so we're going to have damaged fuel.
What do you mean when you say damaged fuel?
- Well, what I mean, technically damaged fuel is fuel
that, it cannot be moved by normal means.
You can't grapple it with a regular spent fuel
tool, and move it about,
is essentially what it means, I mean--
- I don't think-- - That's about all I--
- I don't think we believe there would be
a complete disintegration of the fuel assemblies,
there would be some rupture of the cladding,
there could be some pellets that are released
in the lower portions of the fuel assembly,
but not a complete destruction
of the fuel assemblies within--
- No, no, not at all.
- And we don't believe there was damage
to the fuel assemblies
because the canister was slowly lowered when it made contact
with the shield ring, and was resting on the shield ring.
So there wasn't a drop of the canister,
such that it made an impact that would have caused damage
to the canister, or the fuel ...
- No, no, not in this unit.
- So Eric, I keep calling on you, but.
- That's fine.

- But how about a little more specificity on the,
when we issued the report, what kind
of timeline are we on for, between today
and let's say the final enforcement action
that might be taken?
- Oh, my goodness, I don't have any sense of that at all.
We enter into the enforcement process,
I think the first bar that needs to be crossed is, I think
San Onofre has to answer as to what route they want
to take with this enforcement action within 30 days--
- All right, I'll help you out,
you want me to help you out with it?
- Yes, please.
- I'll help you out a little bit.
Okay, so, so we have to, we had an exit meeting on?
- November 1st.
- November 1st, and so by our own procedures,
where we have to issue the inspection report
within 45 days. - That's right.
- So that would put us out the mid-December, worst case,
we're targeting some time before the Thanksgiving holidays,
we will issue the report with something,
something we call a choice letter,
and essentially they're going to have a choice of,
of coming in for an enforcement conference,
or for a negotiation
through the alternate dispute resolution process.
They'll have roughly 10 days to make that decision
on what they want to do at that point,
and then we will schedule whichever path
San Onofre wanted to take, the enforcement conference,

or ADR, from the time they make that decision
to the time we actually have that conference,
it's about another 30 days to get to that point.
And then it takes the NRC roughly two to four weeks
to issue a final action, following the conference.
And because we are considering escalated enforcement
for two of the preliminary violations,
that does mean that there is a possibility
of a civil penalty, but that's, that's two
or three or more months down the road,
before we're in a position to make
that final determination ...
Did I miss anything?
- Thank you. - All right.
So Eric, any thoughts on whether
or not this is a generic industry issue?
- Well, this issue, it would only have applicability
at one other site in the United States,
and that's the Callaway Nuclear Station out there
in Missouri because there are only
two Holtec UMAX ISFSIs currently licensed.
So, and I think we were out
at Callaway after this event happened,
and they were already putting corrective actions in place.
There was lots of supervisory oversight,
lots of licensee oversight at
Callaway because everyone was very much aware
of what was going on out at SONGS, so.
The existing body of affected users knows very well
what's going on, and they are very aware of
what they need to do to prevent it
from happening at their site.

- And, and
why was the NRC not notified,
following the event?
- Well, that's a very good question.
I believe that it came down to an interpretation,
and San Onofre simply didn't interpret the event the way
that we did because it took for us to prompt them
before they made the proper NRC notification.
And several times in conference calls
and other venues, we asked them, you know,
why aren't you making a notification?
And it took that prompting to have them to do it.
So I think it boils down to interpretation.
- And then we're, so there's a few more questions
on inspection of the canister itself.
Currently San Onofre is evaluating,
through engineering analysis, the, the,
what needs to be done, in terms of inspecting the canister,
or can they, or immediately, or can they do it as part
of the Aging Management Program.
And we're, we don't believe there's an immediate concern
with the canister, so there's time to allow San Onofre
to do the appropriate engineering review work here,
and then they will turn that, they'll submit
that back to the NRC, and we'll take a look at it,
to see if we agree, or if we think something else needs
to be done, in terms of inspection of that canister.
That's an item that's on our plate
for our future inspection, I think,
so in the future, we're thinking in December timeframe,
before fuel handling is resumed,

the NRC will send a team out, the focus
of that team will be to review the adequacy
of the root and causal evaluations
that have been completed by the licensee
to ensure that the corrective actions have been implemented,
and then to complete our review of the analysis
to support this canister in particular,
the inspection of this canister.
And I don't think, and so,
so fuel loading campaigns won't restart
until we've completed our inspection,
and that inspection won't occur until early December,
at the earliest.
Then there's several questions, Eric, on what,
what are the specific regulatory requirements?
So, like, for the, I don't know if we brought
that with us, so the--
- Regulatory requirements-- - 10CFR.
- Well, all the regulatory requirements exist
in 10CFR part 72, but in particular, what is--
- I think that's what they're looking for,
is the citation, so the failure,
the failure to report-- - Oh, that's,
failure to report is 10CFR, part 72
.75(d)(1), is the particular one we're,
we're considering escalated enforcement on.
- Okay, and the failure
to provide redundant drop protection?
- Well, that goes back to their original licensing.
They are a general licensee,
so that would have been part of the 10CFR 72
212-- - Body of--

- Regulations, I think 212(b)(3) is the one.
- Okay, but they actually had the,
what's referred to as a Certificate of Compliance.
- That's right.
- Which required them to implement provisions
under technical specifications.
- Exactly right.
- And the technical specifications themselves,
I believe that was,
it's Tech Spec 5-- - 5.2. whatever, yeah.
- In section 5.2 of the tech specs,
requires that they maintain redundant load drop protection
during movement of a canister,
that's the specific citations for the redundant load.
And then the procedures, corrective actions
and training program requirements all reside
in 10CFR part 72, there's a specific sub-paragraph
for each and every one of those.
- Yeah, and I can tell you those, that would be 72.150,
72 for the, for the procedure parameter,
72.190, the training requirements,
and 72.172 for the corrective action portion
of their violation.
- And there are some questions
regarding asking clarification
on how was the canister misaligned?
- Well,
and Rachel, if you could go back to the,
the slide that has the picture of the, looking down
into the ISFSI vault, I'd really appreciate it.
- You want this one, or you want--

- No, it's-- - This one?

- There we go. - Slide 8, Rachel.

- Slide 8.

All right, if you look down, at the picture we're looking

at now, that's looking down into the UMAX ISFSI vault.

What you see there is a divider shell.

Now, when the MPC, or the canister is moving down

into the divider shell, ultimately to rest

at the bottom of that cavity,

there's very little clearance, there's

about a quarter of an inch clearance

on either side of the canister,

so thinking about it, you're putting a round peg

in a round hole, but that hole is very close

in diameter, the hole is very close in diameter

to the round peg, so as you can imagine,

you have to have that round peg lined up pretty good

to drop it right into that hole.

Now, luckily you have redundant drop protection

that allows you to sort

of manipulate things until you get things just right.

This violation revolves around inattentiveness.

They weren't paying attention to what they were doing,

so instead of paying attention, and getting

that round peg lined up just so, and down into the hole,

they fell asleep at the switch,

and that round peg ended up resting on that divider shell.

- Figuratively. - Figuratively speaking.

- Right, and so,

and so how do they make the alignment adjustment pad,

to get it perfectly centered?

- You know, the VCT operator is key to this

because once you get initial alignment,
there's still some manipulations you typically have to do
because the ISFSI pad isn't completely level.
There's a little bit of a grading of the ISFSI pad,
it's leaning a little bit in each direction
because you want rainwater to run off of it.
So the VCT operator oftentimes has
to position the VCT a little bit to the north,
or a little bit to the south, position a little bit
to the east, or a little bit to the west
to get it perfectly lined up, and in this case,
they thought things were proceeding smoothly,
and you need vigilance, you need the rigger,
or the spotter to be paying attention
to the MPC going down, and you also need the VCT operator
to be vigilant in looking at his indications
because he would notice a loss of load.
You've got two people there, and both
of them failed open in this case.
- So I think there might, Rachel,
there might be a better picture
that shows that alignment, I'm looking real quick.
Maybe slide,
let's try slide 16.
Right, and that kind of shows the stack up
of how, how, in the, the VCT rig,
and how the operator has to position
that entire rig. - That's right.
- To get it perfectly aligned--
- And also, this VCT, the operator,
he can make very fine adjustments

with the vertical cask transporter,
he can bump this thing a half inch,
an inch in one direction, a half inch,
an inch in another direction, you know,
he has a lot of degrees of mobility there,
where they can get these things aligned.
So if you have a good VCT operator,
and someone who's aware of what's going on,
you really shouldn't have a problem downloading these MPCs
into the ISFSI vault.
- Thanks for that, and Patty, are you able
to address chloride stress cracking corrosion, NRC?
If not, we can take it, or I'm trying
to give you a chance here. (overlapping)
All right, so the agency has evaluated the likelihood
of chloride induced stress cracking corrosion.
This is a longterm aging phenomena,
we do not believe it would occur within the first 30 years
of the life of the canister,
that's why we've imposed regulations
to require an Aging Management Inspection Program
to start at year 20.
And one of the specific concerns there is inspections,
non-destructive examination type inspections
that look for chloride stress cracking corrosion sides.
And to date, based on the inspections
that have been done in the industry, we have not encountered
any chloride stress cracking corrosion of a canister,
is that right, Patty? - That's correct.
- Eric, talk more about this canister number 30
that's stored in the Unit Three Fuel Building,
is that allowed? - Yes, it is allowed.

It is an analyzed condition, as they say,
and they can store it indefinitely
in the transfer cask because it's cooled, it is able
to maintain its thermal stability in
that configuration, and it's fine.
- And this actually, this question came
in both during today's webinar, but it was also submitted
through a participant, ahead of the webinar,
and one of the technical staff did some more research on it.
It's actually,
the canister, in a transfer cask, seismically restrained
to the fuel building wall,
is an acceptable condition at San Onofre.
They, the bounding temperature profiles were used
to determine the impacts on the canister,
and the results of that evaluation are all published
in a publicly available section of the FSAR for,
or the Final Safety Analysis Report for San Onofre.
And the numerical results for thermal analyses,
and peak clad temperature, and pressures are all described
in the data tables that go with it.
So this is an acceptable condition for San Onofre.
Do you want to talk about radiation surveys?
- You want me to? - Yeah.
Rachel, can you pull up the slide
on the radiation surveys?
(background noise drowns out speaker)
- There is a schematic of a UMAX lid there.
- Right, so prior, prior to the webinar,
we also received a number of questions regarding
the radiation levels at the San Onofre ISFSI.

This is something, the licensee would periodically do their
own surveys of the ISFSI pad, and the individual vaults,
to make sure radiation levels are consistent
with technical specifications.
What this slide shows is the top of a,
of a UMAX vault, that's the closure lid.
We recently, I think it was two weeks ago,
we had some inspectors out doing
decommissioning inspection activity at San Onofre,
and we decided to perform independent surveys
of each and every ISFSI vault at San Onofre,
the surrounding fence, the beach area,
for those that live out there, the bluff above the ISFSI,
and the parking lot that's also up above the ISFSI.
Every, every reading we took on each and every vault was,
was at least an order of magnitude, if not more,
below the technical specification limit
for radiation levels in the ISFSI area,
and adjacent to the ISFSI, in addition,
San Onofre's required to submit an annual report,
radiological effluents report,
I'm getting a nod of agreement.
And, and they have reported
less than one millirem total exposure to the public,
that's the lowest value you can report in that document.
So again, it's,
the radiological issue of the ISFSI location
at San Onofre is not a significant concern.
- No.
- Not from the actual dose rates
that are present at the, at the site.
And then there's a lot of questions about,

well, what could happen to a canister,
would it be a significant radiological event?
And for an ISFSI, the radiological release concern,
it's a function of the likelihood of a zirconium fire,
and the likelihood of a zirconium induced fire
in a canister goes down, the longer the fuel decays,
the less of a chance there is of a zirconium fire.
These canisters were all helium inerted, so there's,
there's insufficient oxygen to sustain a fire.
And then the zirconium itself is in the wrong form
to support a fire, you really want, to have a fire,
you would want it to be in the powder type form,
and that's not what exists inside the fuel canister.
So again, in order to get that big release
that a lot of people are concerned about,
you really need to get that zirconium fire,
and that's just not a plausible event.
- Yeah, and all this fuel has been cooled
for at least five years in the spent fuel pools.
So you're well outside of the risk range
for a zirc fire event.
- And then I think it's,
and so there's a question on why doesn't
the NRC require realtime radiation monitoring, and,
and that's, so the NRC does require radiation monitoring.
- Right. - It takes place in the form
of exposure monitoring devices--
- TLDs. - TLDs that are,
that are connected to the fence surrounding the ISFSI pad.
So there is realtime radiation monitoring,
but there's not, the NRC doesn't require a,

a digitized type radiation monitoring system,
to where there's the detector,
that then converts that signal,
and then it goes up to a, to a wifi signal
to feed a webpage, or something like that.
The NRC does not require that for ISFSIs,
and I don't know why we don't, I speculate it's
because of a very low radiological hazard presented
by an ISFSI location in the first place.
- Yeah, and don't forget, also, Troy,
ISFSIs are passive mechanisms, they have passive cooling
of a spent fuel, the fuel is getting cooler
and less radioactive over time,
and there's an active surveillance requirement,
where you have to look at each
and every ISFSI vault every day to make sure
that the, the intake screens are clear,
and the outtake screens are clear.
So there's an eye on the ISFSI at all times,
every day, to make sure everything is still in place.
And the radiation monitoring is just added assurance.
- Okay, I'm going to, I'm going to take you back
to canister number 30 again, how is it cooled?
- Natural convection.
You know, all of the fuel in a spent,
in an independent spent fuel storage installation
is cooled naturally, by natural convection currents.
The helium transfers the heat to the MPC shell,
which is then, which is then taken
by the environmental air out into the atmosphere,
it's really simple.
- How does that work if it's in a transfer cask, though?

- The same mechanisms are in place.
- Okay. - In a transfer cask.
It is, you know, there's an annulus that allows heat
to go up, outside of the transfer cask.
- Just scrolling down now, one second.
So there's a question on, Patty, maybe I'll talk,
I'll give you a shot at this.
Can chloride stress cracking corrosion breach a canister
in less time than
the Aging Management Program would detect it?
- No, we don't believe it could.
Stress corrosion cracking takes awhile
to get to a canister, and
we don't think that would, it would.
- Yeah, so what Patty's saying is that the,
in short, the answer is no, it's a,
chloride stress cracking corrosion is a,
takes a long time to occur,
our studies suggest it would take more than 30 years.
Aging Management Programs start at year 20, and,
and that program requires
that the licensee determine the most susceptible containers
for the inspection.
And so we don't believe there would be cracking due
to stress, chloride stress cracking corrosion,
before we detected it was occurring.
(background noise)
I'm scrolling through the questions
that are being sent out to me.
Canister 30.
We do have questions on keeping spent fuel

at San Onofre, and the transfer of fuel

to a permanent nationwide waste storage facility.

- Yeah. - Permanent?

- Yeah.

- Or an interim consolidated--

- Either, something that moves it away from San Onofre,

is that something you can talk to?

- Well, we do have two,

two license applications in

For consolidated interim storage facilities,

one in New Mexico, and one in Texas,

they're actually right across the border from each other.

So we have to review those, those licensing applications.

So there is a possibility for movement there,

if that's what the licensee intends to do,

to move it off of the site.

- And I believe it would, we're still waiting

on some type of Congressional level action

to take place for a permanent repository

for high level waste. - Correct.

We do not have a permanent repository for disposal.

- I'm not sure, I don't think I have

the right people here today to talk about the--

- whistleblower protection?

- Yeah, do you?

I don't think we've inspected that,

you haven't, Eric, have you? - No.

- Yeah, so there's some questions

involving whistleblower protection,

and safety conscious work environment.

So the regulations still apply

and are in effect at San Onofre for,

for employee protection rights,
that would include whistleblower protection rights,
employees, and we do go out,
I don't have the right inspectors up here today
to talk about our last inspection
of the safety conscious work environment program
at San Onofre, but employees do have the right
to bring forward safety concerns, and not be retaliated.
And if they, if they feel that the licensee
has been unresponsive to their concerns,
or they think they've been retaliated in some manner
for raising a concern, they can always reach out to the NRC,
they can call our Headquarters Operations Officer,
they can call anyone in the regional office.
We'll capture that concern, we'll enter it into our process.
So that's always an option for them, that you
could even call our Office of Investigations directly,
if that's what they wanted to do,
if they didn't want to talk to an NRC inspector.
So there's a number, number of pathways, we take those
in the mail, telephone, email, anonymous,
a person's name attached to it,
any form, we'll take that, then we'll,
we'll either inspect it or investigate it as is appropriate.
Okay.
Right, now I'm scrolling through the questions
that are coming in.
- Did I see one about a criticality analysis or--
- That is there, what's the chance of a criticality of?
- Well, the licensee actually provides information
about a criticality event, and in the absence

of water in the cask, and along with the,
with the boron impregnated lattice structure
in the canister, criticality is, cannot happen
in a dry cask, in a dry fuel storage canister.
It is just, you can't get there.
k-effective is so low,
you can't get the multiplication of neutrons,
without water, and with the boron, again,
and the lattice structure of the canister, it's impossible.
- Okay, and there are some followup questions regarding the,
it's with the opening of a canister, once it's been,
once it's been put in a vault,
and then taking it back out and whatnot, that's something,
if a canister had to be opened, or repackaged,
that's not something that's going to take place very quickly.
The first step would be for the licensee
to establish a safe environment
to transfer that canister to, it could be,
most likely it would be a hot cell of some sort,
so if you're at a fully decommissioned facility
where there's no structures left,
like San Onofre will be in the future,
they would likely have to, to either, one,
they would have to figure this out,
and get NRC approval, but they would, one,
have to either build a hot cell,
or a radiological confinement purposes.
It might be something where they could
have a vendor, or somebody construct a new shipping package,
and then just repackage it into a different type of device
for shipment somewhere else.
They, it might be something where you could put it back

into a spent fuel pool, but that would have
to be closely evaluated before something like that's done
because the, the fuel is hot, the canister is, you know,
there is, it is at an elevated temperature.
So you'd want to make sure that you'd carefully analyzed
and studied the impact of a, of a water shock
on the canister before you put it in a water environment.
- And, and to add to that, Troy,
remember, when it comes to radioactive decay,
time is on your side, the longer you wait,
the safer it's going to be. - That's right.
And there's a question, well, if the canister is dropped,
how are you going to get it back out?
And, and again, the licensee isn't required
to analyze for a load drop event,
that's why we put in the license,
the requirement for redundant drop protection at all times.
And again, that's what made the August 3rd event
so significant, was,
was the loss of redundant load drop equipment.
So they don't have to analyze for a load drop,
I don't think anybody's really, and maybe,
Eric, you can correct me-- - I want to say
that San Onofre has demonstrated the ability,
during their dry run operations,
to retrieve a canister. - An undamaged canister.
- An undamaged canister, right.
- Right, and so the question is,
if you dropped it that 18 feet,
and you somehow deformed the canister, which we don't,
right now, our evaluations aren't showing

that there would be a canister deformation
from an 18 foot drop, but hypothetically,
I don't think anybody's analyzed trying
to pull a stuck canister
from a drop out of the bottom of the vault.
I just, I don't think it's been done, and again, it's not,
the NRC doesn't require that type of analysis.
What we do require is redundant load drop protection
features so that you cannot drop the canister.
And again, we don't, just to go back to the consequences
of the August 3rd event, that this canister was,
was lowered in a slow and controlled manner.
It made contact with the shield ring,
and then rested on it, and then the slings were disabled
because they went completely slack,
and therefore, we don't believe there's any damage
to the canister, or to the fuel assemblies inside.
So this would be no different
than if they successfully lowered the canister all the way
to the bottom of the vault, when it finally made contact
with the surface, it would have been an easy,
slow mating of the surface.
So there's, we don't believe there's any fuel damage
whatsoever to the affected canister.
(inaudible)
- You want to talk about that at all?
- Yeah, you can.
- Well, there's a question here about criticality,
due to water entering through a crack.
If there was any evidence of a crack in a canister,
they would have to take immediate actions
to either re-containerize that canister,

or remove the spent fuel contents, or repair.
- And we actually think cracks, when we're talking
about cracks, we're talking about weld cracks,
and that would most likely occur
from a canister in storage, due to some type
of stress corrosion cracking, and again,
the Aging Management Program is set up such
that you detect the early signs of cracking,
and you have the option to, the ability to make repairs
before you would actually have a through wall crack
of the canister, and in San Onofre's case, again,
they're, they have an agreement with the state
of California to have that Aging Management Program
in place by year five, which is well,
well more conservative than what the NRC would require
for a similar equipment.
Now, one of the questions, I see some in here,
Eric, and I know I've asked you,
so they've been, San Onofre's been moving fuel out
to the pad for a long time.
Why isn't this something the NRC, all these weaknesses
with oversight, and procedures, and whatnot,
is this something that the NRC inspectors should have picked
up on from the very beginning?
- Well, you know, and I think me and Troy were talking
about this earlier today, you know,
NRC inspectors, we go out to these sites
where they have to demonstrate for us their ability
to safely load fuel, and while we're out onsite,
and when NRC's there, you're going to have lots
of management oversight out there, also,

you're going to have lots
of supervisory oversight during these activities
because everybody wants to get it right
for the NRC, you know?
I mean, we've talked about some aspects
to them having their A team out there
during these operations, and even for the first loading,
you know, they're going to have their best performers out there
because nobody wants to fail in front of the NRC.
I think what we saw out there at SONGS is,
with time, you have turnover of staff,
the A team leaves and moves on, and you know the amount
of people you have monitoring these operations,
it goes down, in a very real sense,
radiation protection programs don't want a lot
of people out there standing around, soaking up dose
because it's not good for their numbers, you know?
And so you end up having a situation,
what we had out there at SONGS,
you have fewer and fewer people out there,
actually observing the operations.
When we were out there observing dry runs, you had everybody
and their mother out there watching these operations,
but once we left, you know, they get into a little bit
of a battle rhythm, and they start fighting
with things like dose, and oversight falls off.
Instead of having two people up in the man basket
during downloading operations, now you have one.
Instead of having supervisors observing
every little thing you're doing
because NRC's looking over your shoulder,
you have, you know, you have people down

in the low dose waiting area,
just having a little bit of a chitchat, maybe.
And you end up in a situation where we ended up here
on August 3rd, it's unfortunate,
but, I mean, that's what sometimes happens, I believe.
- Yeah, so I think when we inspected during the,
during the dry runs in early,
during the initial loading campaigns, what we observed was,
well-qualified people involved in the evolutions,
and plenty of management oversight
and quality assurance oversight to observe and make sure
that everything was being done correctly.
And so when you have well-qualified people,
and a lot of oversight, you can get by
with procedures that don't prescribe each
and every little thing somebody has to do
because they're knowledgeable of the work
that has to be done.
And then, I think in San Onofre's case,
as they got past the first couple of loading campaigns,
and they started to experience turnover
of the riggers, and some of the contract force
that was available to them, they didn't maintain
that same level of rigor, and rigor and quality
in the training program.
And so now you had people being put out on a job site
that had less knowledge than what the original team had
when they first started.
And then, and so when, and that's okay,
to even do that, but you have to balance these three pieces.
(overlapping)

So if you have people come out, and you put 'em to work,
that have a little bit less knowledge, then,
then the procedures have to go up
to account for that, or you have
to apply even more management supervisory oversight
to monitor all the critical evolutions.
And in this case, what happened was, we ended up with people
that had less qualifications, or less knowledge,
and the oversight piece slowly backed off, and so,
and then the procedures were never updated
to reflect the gap left by a decrease in oversight,
and a decrease in knowledge.
And so, so that's not, for the,
I think for the, we expect the licensees to be able
to manage and balance those three pieces of the puzzle,
and the NRC can't be there every day to do that,
that's why we give these folks a license,
and that's why it's their responsibility
to stay on top of it.
We did not think there needs to be a design change
to the vault storage system at San Onofre,
it is possible that, with the right corrective actions,
and put into place, that provide the critical parameters
and measurements that need
to be made during the downloading evolution,
people with the right knowledge and skills,
and the right level of oversight, you can safely lower
that canister down into the vault
without making a design change to the, to the vault system.
- Right.
- And then, and then there's a question
about the notification, and--

- Do you want me to answer that one?
- And there is a difference between a courtesy call,
and a formal notification
to the Headquarters Operation Center.
That call to the Headquarters Operation Center
starts everything for the NRC,
and it also is a way for the public to get aware of events
that have occurred at a licensee's facility.
But when that call is made to the Headquarters Ops Center,
they're, our operations officer immediately calls
the regional duty officer that's on call,
and that initiates the NRC's response actions.
And so it is significantly different
to have an immediate report to the ops center,
than trying to catch somebody in the regional office,
to let them know that something's going on with the site.
And how about you take external events?
Seismic, do you have that one?
- Sure.
- We have a slide for that, too.
- Yeah, the, the problem I have
with this one is just, it's, well.
- I can take it.
- Okay, you go ahead and take it.
(background noise)
- So, Rachel, can you pull up 39, slide 39?
Seismic and flooding, so there's some questions
on seismic and flooding, I'm going to refer
to that as tsunami, so the ISFSI systems
at San Onofre are evaluated for earthquake,
they are evaluated for a maximum flood height,

and flood velocity, at San Onofre, the,
I'm going to refer to the UMAX system,
but the TN system's a little bit different,
but it's not as,
I don't,
the UMAX has a,
it's designed to withstand ground motions of 2.1 Gs
in the horizontal, and one G in the vertical direction.
The San Onofre design basis earthquake is 0.67 G,
so it's, there's plenty of design margin
for earthquakes at San Onofre,
and then, with respect to flooding,
the UMAX system
is designed to withstand flood levels up to 125 feet,
that's 125 feet, fully submerged.
The Transnuclear system, it's 50 feet, fully submerged.
For those that are out on the West Coast, and have been
by the site, you've been down around the beach,
you've seen the seawall, atop of the seawall,
just as a reference point, is 28 feet.
And the maximum design tsunami wave height
is roughly 27 feet, so there's plenty of design margin
at San Onofre for both flooding, and for seismicity.
And then we're back to the unpacking, so,
of a canister, if required, so that,
San Onofre, nor any other site,
is required to maintain a spent fuel pool,
solely for the purpose of repacking,
or opening a canister, there are other safe ways
to do that, if required, or needed by a facility,
they would have to determine the safe radiological facility
to do that evolution in.

Most likely, it would be, involve some type
of construction of a hot cell to do the work.
But there are other options, again, that would be
on the licensee to figure out the safest option that works
for their facility, and then the NRC would approve that.
But they are not required
to have a fuel pool to do the work.
And then there's a question about evidence,
with respect to damage to the canister,
or other canisters in question,
during the downloading evolution.
That's still something, San Onofre is still analyzing
that question, we've put that to them.
We think there's probably been some metal to metal contact
during downloading at more
than just this canister in question,
but if you go back to the photo,
Rachel, maybe you can remember it, the.
Look, the one with, that says, "Look close."
That one, thank you, Rachel, so if you look,
if you look close at that photo,
you can tell there was contact between the canister
and the shield ring, but,
there, and I think, and we've examined this photo,
and in detail, it,
essentially it's just paint scrape-age off the,
off of the shield ring, off the divider shell.
So we don't think there, if there was some wear marks,
they're not significant wear marks on the canister,
and I believe the acceptance criteria
for wear indication on a new canister is gouges up

to a quarter inch depth, and we certainly don't believe,
at this time, that there would have been gouges
that even come close to a quarter inch depth,
due to a downloading operation.
Therefore, we don't think there's an immediate concern
with the canister, but that said,
we're waiting on San Onofre to complete their analysis
for not only wear marks on the canister in question,
but the other canisters, and what type of impact will
that have on their longterm Aging Management Program.
The other piece with that is,
is these are stainless steel canisters, and even
if you did have scrape-age on the canister's surface,
it's likely you would re-oxidize the stainless steel layer
that was scraped, prior to the onset of some type
of chloride pitting, or stress cracking, so.
But we're still going to wait for the analysis,
and do our full review.
So there's a question on the hot cell, again.
So canisters don't have fast breaking emergencies,
and so, so what would likely happen--
(inaudible)
What would likely happen is, is the,
through the Aging Management Program,
you would identify an indication, or early signs
of cracking of a weld, and you would have the time,
because chloride stress cracking corrosion
is a longterm phenomena, you would have the time
to construct the hot cell, or repackage the canister
for shipment elsewhere, if need be, and do the repair work.
We don't see this as something
where you have an indication one day,

and you must make repairs that afternoon,
that's not the type of scenario we're talking about.
These are long range, lots of time available types
of repairs, okay, we have some questions on shims,
do you want to take shims?
- Rachel, you want to go to 34?
Oops, 34, is that it?
Do you have the shims? - Let's try slide 34.
- Oh, oh. - Or--
- They changed the slides, okay.
- No, there you go.
- That's, that's the one I'm thinking, so in this picture,
it shows the bottom of the shims, so the original design
was called the monolithic shim standoff,
and that's why see on the left hand picture.
And Holtec changed their design
to the shim standoff pins, which are shown
on the right hand of the, the right picture.
The pin design has a possibility
of failing during fabrication process,
and during transportation of the canister,
and since this issue had been identified,
Holtec has ceased application of the pin,
of the pin design, and replaced existing and new canisters
with the original monolithic standoff design.
This change to the shims was the subject
of an NRC inspection done by headquarters,
by my team, out at the Holtec Camden, New Jersey facility.
Results of the inspection are still pending,
we reviewed the thermal analysis
that had been provided by Holtec,

and the agency does not believe there's
an immediate safety issue with any of the four canisters
that were loaded with the shim pins at San Onofre.
So additional information will be available,
once we issue the inspection report,
which we hope will be sometime soon, in the next few weeks.
- If you see something.
- This may be for you to answer...
- Yeah, so I'll, so there was,
there's a question that came in on,
on the NRC doing unannounced inspections.
That's, that is a part of our tool bag,
we do use that, but it's mostly,
mostly at our other materials licensees,
hospitals, radiographers, those types of facilities,
most of those are unannounced.
Of course, our resident inspectors
that are at the operating sites,
most of the work they do is unannounced inspection activity.
We do have that option, and maybe that's something we think
about with our inspection program, is do we announce all
of our fuel loading campaign inspections,
like with our current practice?
Or do we just go out, unannounced?
Part of the problem, at San Onofre,
it'd be a little bit easier because they,
theirs is a longterm fuel loading campaign.
When Fort Calhoun starts next year,
it'll be a many month window, and so we could do that.
But most of the time,
these are short duration type campaigns,
and so we have to coordinate with the licensee

to understand the schedule for, for a fuel loading campaign.
And so it's not that we can't do unannounced,
but it is a closely coordinated activity,
the schedules are, but that's something we can talk
about later. - Okay.
(inaudible)
(inaudible)
- A lot of these questions, people have the same questions.
- Yeah.
So the, the presentation slides are,
are already available on the webinar handout link,
they're available on the NRC Spotlight.
Any slides we use today to answer,
to help support some of the Q&As,
questions and answers, those will be attached
to the meeting summary that'll be published following,
within two weeks of, I think of today's discussion.
The session is being recorded, and we do plan
to upload that to the NRC website,
and the conversation that you hear will all be transcribed,
so you'll have a text version of today's presentation,
as well, for review.
So, and we have a question on,
how do we enforce the licensee's commitment to us,
to cease fuel handling activities.
So the licensee, when they called us on the sixth,
and then again on August the 7th,
verbally committed, that came from the site vice president,
verbally committed to cease all fuel handling activities
at San Onofre until the NRC came out and inspected,
and was satisfied with the corrective actions,

at which point, they would, once we,
once the NRC was satisfied,
they would resume fuel handling activities.
And so for now, we're taking the licensee for their word,
that they're not going to refuel, and to date,
they have not done fuel handling activities
since August the 7th.
If, for some reason, the licensee decided they weren't
going to wait for the NRC, and start moving fuel this week,
once we became aware of that, of course,
we would talk about it internally.
We have the option to impose a confirmatory order,
ceasing fuel handling activities at San Onofre,
if we chose to do that, but for now,
we don't believe the licensee is going to make any attempt
at fuel handling activities, and so we're comfortable
with where we are, and not, and the licensee is comfortable
with waiting on us to do our inspection activity.
In addition, we have at least a,
a weekly phone call with the licensee team,
to talk about their progress with the causal evaluations,
engineering evaluations, implementation
of corrective actions, retraining and qualification
of the staff, so that takes place once a week, so,
so I think we have a pretty good handle
on what they've done, and where they're heading,
and the timeline they're on to be able
to resume fuel handling activities.
And I'll, I don't,
I'm going to have to, I don't know the answer
to this question, maybe one of you guys can send me a note,
but it's, will all questions be made publicly available,

and I don't,
and I'm getting indications from my IT staff
that the chatroom, are we going to make the,
we can make the chatroom publicly available?
Yes. (laughs)
They didn't want to, they didn't want to be heard,
though I got a thumbs up, yes. (laughs)
And again, the NRC doesn't require drop testing
because the load drop event's not supposed to happen.
We require redundant load drop protection,
we require that, the load drop protection to be tested,
so those slings have to be tested,
they have to meet industry codes,
lifting equipment has to meet industry codes,
and if you implement that program, as we required it,
you would not have the drop event, so.
Therefore we don't require drop testing.
There are, there is some drop analysis that is done
because you do have to lift the canister a certain height
in order to move it from one location to the other.
Those heights are small, they're on the order
of one to two feet, and licensees do have
to do drop analyses for those distances,
or heights, if you will.
So this, so there's a question,
would this event be possible with a standard,
above ground ISFSI, so there are some sites
where, where they do some of the cask,
the transfer cask loading in a pit that does require a lift,
not to the same height as the UMAX storage vault,
where you have that 18 foot vulnerability,

but there are some where it's more than,
more than a one or two foot lift to, of a canister.
So, and those sites, well, at all the sites,
they're required to have the same, they're required to meet
the redundant drop protection we require at all sites.
- Right.
- So it's not, it is directly applicable
to the UMAX design, but there are some sites,
because of the configuration of their fuel building,
where they have to make a similar type of lift,
and they're required to have the redundant drop protection.
I think we've addressed all, did you,
I haven't seen, I think we addressed--
- No. - All right.
(inaudible)
Hmm?
And, and we've asked ourselves that same question, do we,
should we make licensees have a drop analysis
in their final safety analysis report,
given this event, and we've talked about that,
and the answer is no, we need to make sure licensees comply
with the redundant drop protection feature.
Had San Onofre complied
with the redundant drop protection features,
there would have never been a near-miss event.
- Hmm, that's an interesting question.
- And so the other one is, did we,
should we require Holtec, or San Onofre,
or other licensees to use, on this,
we're going to talk specifically about San Onofre.
So should San Onofre's training canister be full size?
So you heard Eric talk earlier

about there being an additional three quarter
of an inch clearance, it's okay for the actual,
for the equipment used in training
to be different than what's actually in the field,
but the training program has to teach the workers
what those differences are, and how
to compensate for that difference in the field,
during actual conditions, so we don't have plans
to require a full size canister be used during dry runs
at San Onofre, but we do expect the training program to--
- Acknowledge the differences.
- Acknowledge, and train on the differences.
- Exactly.
- And I think, and we'll re-answer this question.
So San Onofre, the question involves
removing a canister from the vault,
and San Onofre has the capability
to remove a canister from a storage vault.
Just, the canister in question did not drop,
so we don't think, so, so there's no damage
to that canister, no damage to the fuel.
Had it dropped,
the early analysis suggests
that there would not have been a sufficient deformation
to the canister, such that we would not have been able
to remove it, but in any event,
it didn't drop, so that's, that's
not something we have to consider today.
"Why are two slings on the same device redundant?"
- Well, you want me to answer that one?
- You can, you can say it out loud.

- Okay, why are two slings
on the same device considered redundant?
Because two slings on the same device are redundant.
If one of the slings would have failed,
the other sling would be there to carry the full weight
of the canister with a lot of margin,
with some margin included.
Unfortunately, as I've stated earlier,
this is sort of an extraordinary event,
where the vigilance of two individuals both failed
open at the same time,
and that's a very unfortunate situation,
it is really, in essence, why we're here right now today,
discussing the event, and why San Onofre is put
in the position to ensure that this,
an event like this can never happen again.
- The slings are attached to different points, as well.
- Oh, yeah, yeah. - Yeah.
- Each sling is attached to a different point at a canister.
So any given sling could fail,
and the other sling would be able to support the load.
- And I don't, maybe you know this one, too,
any, the differences between Callaway's system, and,
and San Onofre's, the vault?
- There are subtle differences between the two systems,
but for all intents and purposes, they are the same.
You know, San Onofre has a somewhat longer fuel
than Callaway, Callaway has a shorter canister,
SONGS has a longer canister.
So there are those differences,
Callaway's MPC is slightly more narrow
than the MPC being used out at SONGS,

but those differences are as far as it goes.
It's still the same stack up configuration,
it's still the same downloading operation at both locations.
It's just that, I think the real difference is
that San Onofre, it was in the production mode
of loading numerous canisters,
and Callaway has only been involved
in six, in 12 cask campaigns so far.
Far less than were loaded out at SONGS,
and so SONGS had a much more of a opportunity
to have an event like this happen, so.
Yeah, and the shield ring, it can,
at Callaway, is actually further down into the ISFSI vault,
further down on the divider shell than it is at SONGS.
So by the time you make it that low
in the Callaway divider shell,
you're probably fairly well aligned,
whereas when you're up that high,
when you encounter the shield ring at SONGS,
you're probably, and the evidence bears it out,
you aren't very aligned at all.
It's more of a, more of a nuanced approach they have
to do out there when they're downloading than at Callaway.
- Rachel, can you pull up slide 35, please?
There's a question specifically regarding canister 29,
radiation levels, and if you look in the bottom right corner
of this slide, we actually have the gamma radiation levels
from canister 29 on the slide,
the lid was .015 millirem per hour,
and the outlet vent was 0.12 millirem per hour.
It just, it just happened that canister 29 was the,

had the lowest radiation level readings
of all the storage vault, UMAX storage vaults at San Onofre,
and it was the canister involved in the event,
which gives us a,
kind of reconfirms that we don't believe there was damage
to any of the fuel assemblies,
or any damage of significance to the canister, as well.
And then, is it, is a horizontal vault more safer
than a vertical vault, or vice versa, and I think
we believe they're equally acceptable, equally safe.
And then
the VCT operators, were they,
were they around during the July event,
or were they new since the July event?
Do you have a perspective?
- This particular VCT operator involved,
in the August 3rd event,
was present onsite during the July 22nd event,
however, there was no communication or no,
no operational experience passed on
from that VCT operator to this one.
It is actually one of our biggest concerns
at the San Onofre site, is that,
depending upon who you spoke to,
there was a vastly different amount of experience
and amount of knowledge, given one person versus another,
in our interviewing of people out at SONGS.
And that was one of our findings, was that a lot
of this operational experience wasn't being fed forward
to other cast members, it wasn't being shared freely
among all of the workers onsite,
and it really should not be that way.

Everyone should have the benefit
of all of the experience that's going on on a site,
but out at San Onofre, this was not taking place.
- And Patty, I had a couple of questions coming in
that I think are going to be your territory, right?
So the, for the proposed interim storage facilities,
do you know, are they being proposed as vertical,
or horizontal, or is it too early to know?
- So one of the, one of the license applications
is actually UMAX, the Holtec one that's in New Mexico.
And then the other one is,
is
multiple, I mean, it can be the horizontal,
I believe they can, they're also proposing
that they can handle other ones, like the HISTORM
that's just up on the pad, vertical.
- Vertical or horizontal?
- Vertical or horizontal, but not,
I don't think they're proposing, you know, beneath grade.
- And then the, and then just a canister
life,
right, from, so I know we initially licensed for 20 years,
but can you get a perspective on the beyond 20?
- I can actually give a little bit of perspective on that,
because canisters, at least the Holtec UMAX components,
they have a license life of 20 years.
And they have a design life of 60 years,
and they have actually a service life of 100 or more years,
with proper maintenance and surveillance activities.
So that goes into the designing
of the dry cask storage systems.

- Okay, and then they, they're,
they have to come in for license renewal,
prior to year 20?
- Right, they have to come in for license renewal,
prior to year 20, and then they,
their renewal can be up to 40 years.
- Okay.
And then
there's a question on the radiation reports
and measurements that we took,
and it's my plan to have the staff document, in the next,
well, they're writing, in that decommissioning
and inspection report now, as we speak,
and we plan to attach all our surveyed measurements
and data tables to support the work of my two inspectors
that were out at the site, so that will be included
in an inspection report.
And, and so there's a question on
when the canister was aligned with its weight shifted,
doesn't this warrant the canister being opened
to inspect the fuel, and so I'm going to go back
to the picture that shows the transfer cask
on the vault door.
And I wish I had a dimensional slide,
I know Eric's pulling it up, which one?
- It's this one.
- I think the one, that one right there, that top one, no.
- This one? - What is that?
- 11. - 11, slide 11, Rachel.
So the canister's inside the transfer cask.
What you see here is the transfer cask,
and if we could look down on top,

and see a cutaway, it's a pretty,
the tolerances are pretty small,
between the canister and transfer cask.
And so what we believe happened is,
when the canister was lowered and it made contact
with the, with the shield ring, it most likely tilted,
but it wouldn't have tilted very much at all.
And maybe you have a perspective on that,
I know I don't have a real perspective.
- Well, it'll tilt probably at the order
of maybe one to two inches, but that's all.
And when it tilts like that, it is completely suspended.
- Right.
- Unless something happens to jostle it.
(overlapping)
- Well, it wasn't suspended, it was resting
on the shield ring, but it wouldn't have been a,
a sudden, it hit the shield ring, and then slammed over
into the transfer cask, that wouldn't have happened.
It would have rested, it would have rested gently
on the shield ring, and then gently made contact
with the transfer cask. - Side of the transfer cask.
- So the inside of the transfer cask,
and so there's not enough force
or stress being placed on the canister at that time
to give us concern about the integrity of the contents.
- Right, the downloading process is a very gradual process.
They come down with the lift beams
on the vertical cask transporter
in a very slow and methodical fashion.
- And, and Patty, I don't know the answer to this.

It involves warranties of the UMAX system,
versus the warranty of a canister, I don't--
- I'm not sure what they mean by warranty.
- Okay, I don't, Eric, do you have any idea?
- I don't know. - All right.
So we're going to, that's one that we'll take away,
and maybe Lee, in the back, you can make note
of that one, and then we'll do some research on that.
We have, on the NRC Spotlight page,
we have posted some FAQs on that page,
and we'll take a look at this,
and depending on what kind of answer we get,
we'll put that back on our FAQ, on the NRC Spotlight.
And what's the structural rating of the shield ring?
That's something that,
that, as I mentioned before, the licensee's evaluating the,
the drop analysis of the, what would it,
what would have happened, had there been an actual drop?
And I think that's something the,
the capability of the shield ring to support the weight, and
that's something that we still
have asked some questions about.
- That's right, according to Holtec,
the shield ring can support the full load
of a dry cask storage canister, however,
that's not what it's designed for, so, I mean.
In that regard, if we understand that's not
what it was designed for, and so they get no credit
for having the analysis showing it would support the MPC,
because that's not what it was designed for.
- And,
and we asked this question earlier today,

or yesterday, we were talking about it.
So, if at the end of the first,
the initial 20 years, the licensee says,
we're done, we're not going to renew.
- Yeah, okay, so if they say they're done,
and not going to renew, so it depends on who's saying that.
So you've got the certificate holder,
with all their general licensees,
who are using their systems, and if they decide
that they, they aren't going to renew the certificate,
the licensee can actually renew the certificate,
if they choose to, so that they can remain,
continue to, to have their spent fuel
in that, their, that cask system.
If it's a specific licensee, they would have to have a plan
on how they were going to exit out of that, so.
That's the answer, they, I mean.
- And the, and I would think that the NRC can always impose,
through orders of requirements
that would replicate a renewal period.
- Right. - It's, right.
To ensure that there was longterm safe storage,
so the, the licensee, ultimately,
is still responsible for the safe storage of that.
The NRC has legal options we could pursue
to make sure that takes place.
Eric, what's the shield ring actually designed for?
- You know, there are a lot of good aspects
to a lot of these dry cask storage designs.
For instance, the shield ring, in and of itself,
helps to reduce radiation dose out there

on the ISFSI pad, so it's saving dose for workers,
sort of at the expense of downloading your MPCs.
The same way the cone that we showed you on top
of the MPC, that's also designed
to help reduce, I mean, reduce radiation dose
to the workers, so it's a good idea.
- And then there's a question along structural integrity,
regarding the MPC 37 canister, just in general.
And these are robust canisters, they're,
I think the bottom surface is almost three inches thick.
- Yeah, it's three inches thick,
the top lid is nine inches thick,
and the shell itself is five eights of an inch.
- Five eights, so well, so over a half inch thick,
and this is all high grade stainless steel,
so we do not have issues or concerns with,
with the structural integrity
of the multipurpose canister 37 design, very robust,
highly capable of maintaining the integrity
and the confinement barrier.
And the shield-- (overlapping)
Rachel, can you go back to the shield cone picture?
- Yeah, you see the green slings?
You probably missed it in my initial discussion,
but those green slings are there
for retrieval of the shield cone because it,
it's going to be used again with the next MPC
that is downloaded, so the shield cone comes out,
along with the yellow slings, and the MPC lift cleats,
something we hadn't discussed too much,
all come out after the canister has been installed
in the ISFSI vault, that way they can be used again

on the next canister.
- And then they put another, another lid on top
of all that, to seal it up, the vault up.
- That's right. - Right.
- That's right.
"...MPC Guide. - With the sole purpose
of helping to guide the canister into the hole. It's not a shield ring."
- Well, honestly--
- Let's read the question out loud.
- Oh, I'm sorry, you read the questions for me, and I'll.
- Okay, so there's a question regarding the, the
guide ring
versus a shield ring,
so is it, is it really something
that helps guide the canister,
or is it providing shielding, or is it a little bit of both?
- Rachel, if you could go back
to picture, slide number eight?
So,
those guides that you discussed in your question,
they're actually the gussets that are on top
of the shield ring, and they are there
to help guide the MPC into the storage vault.
But the shield ring, in and of itself,
as I mentioned earlier, is there
to provide radiation shielding
for the MPC while it's in storage,
and should reduce radiation dose to workers,
and out on the cask.
So we're sort of talking about the same thing,
and they are part of one another,

but the shield ring and the guides are connected,
but separate, so. - Okay.
And then, and then the cables, the slings,
and the yellow ones, is there,
is there a required inspection program for those,
and what does that involve?
- Yeah, the slings are actually, they're,
the guidance that you follow when,
when designing and making slings is ASME,
that's the American Society of Mechanical Engineers,
30.9, and it spells out all the requirements for slings, in,
in the design.
- Do they have to be load tested?
- Yeah, load tested requirements,
how much of a dynamic load you're going to impose,
in addition to the load rating,
and all the slings out at SONGS,
they're actually load tested to twice their rated capacity.
- And the yellow covers on the slings,
are those removed for inspection, or how does that work?
- Well, actually, they're actually areas
on the slings where you inspect them.
Now, we don't have a picture of this,
but if you look at a sling up close,
they'll have a little bitty tell-tale on it.
And any time that tell-tale begins to move inside
of the sling, it's an indication
that the slings are wearing.
And so if that tell-tale disappears, it's time for you
to get rid of the sling, and purchase a new one.
- And is that something they would inspect
before each lift, or-- - Absolutely.

Yes, the slings are inspected before each lift,
when they're being installed on the MPC.
- Rachel, can I get you to go back to
that other slide on the vault?
That one, so, so earlier, we talked about the,
the spotter said, said it was four feet down.
- Right. - Right?
And we said, and how there was some confusion about,
was that four feet below the shield ring, or whatnot,
about how far down is the shield ring from the, from the--
- The top? - From the top?
- About four feet. - About four feet?
- Yep. - Okay.
So that would be somebody standing on top,
with a camera, could easily take that,
zoom in on it, it wouldn't be an issue for,
for that, right? - No, no.
- And that's an empty vault there?
- That's right, that's right, and I took that picture.
- And Eric says he actually took that picture, so.
- I took them all.
- So there's a question that says, if they have gussets,
are there to guide the canister into the storage vault.
Why is the fact that they actually fail
to do what they are designed to do not being addressed
by the inspection report? - You know,
that is something that we are addressing,
as part of our special inspection.
And it's, it's the,
there's an important nuance here.
When you guys look at the shield ring,

and you look at the gussets that are there
to guide the MPC into the canister,
there is a little bit of an offset
in a lot of these shield rings and gussets,
where the gusset does not go flush
with the interior surface of the shield ring.
And that's actually a,
an engineering enhancement that they actively made out
at the Callaway site, to address those gussets
in the fabrication of their divider shells.
We had questions during our inspection,
why weren't any of these enhancements fed forward,
out to the divider shells used at SONGS?
And the fact of the matter is simply
that the divider shells at SONGS were all manufactured long
before Callaway got out to perform their,
their vendor inspections out at Holtec,
and had those enhancements put in place.
So there is, those gussets aren't perfect,
is what I'm saying, there's still a little bit
of a lip inside of that gusset,
about a quarter of an inch, on a lot of these shield rings,
and that's unfortunate.
- Yeah, the key factor here is
to make sure you have the correct alignment
from the beginning, before the canister gets
to that part of the shield ring,
before it starts to approach the shield ring,
so that you don't have the challenge
of the canister making contact
with the shield ring in the first place.
- Right.

- And, and we don't believe there's any plans to,
to enhance the gussets used at San Onofre.
So there's a question about the radiation levels
during loading, and being concerned
about the amount of radiation during loading,
if you have to have folks go to a low radiation area.
So just as a good ALARA,
as low as reasonably achievable practice,
you want, you want the staff involved, and working
in radiological areas to minimize their exposure.
One way to do that is to take advantage
of the distance from the source of the radiation,
and so many licensees will adopt a low dose waiting area,
or low dose area during any job site type of evolution,
and so it, it was appropriate for San Onofre
to designate a low dose waiting area, but you have
to balance that with maintaining the right level
of oversight at the job site
to ensure quality standards are maintained, and so.
And I think the, during the downloading, there's,
there is one part of the downloading
where there is a radiation streaming effect
from the canister. - There is.
- And those levels are about--
- Well, at San Onofre, those levels can go as high as
three and a half R per hour, and actually,
what ends up happening during downloading operations, most
people will post the area immediately around the VCT,
during downloading, as a locked, high radiation area,
which requires special dispensation
to be able to enter into that area,

and so they restrict a lot of people.
Everyone but who is absolutely necessary
will not be in that high, locked high radiation area.
But in this case, I think they could have found
a better area to have staged themselves,
where they could still observe downloading operations,
and not have an obstructed view,
as they did in their low dose waiting area.
There are other areas on top of the ISFSI pad,
for instance, where they could have gone,
and not been in a locked, high radiation area.
- Yeah, and just to put it in perspective,
a locked high radiation areas are greater
than 1,000 millirem per hour.
- That's right, one R per hour.
- And so it's acceptable to work
in the locked high radiation area.
You do want to provide
the appropriate rad engineering controls for workers
that are in, that work in those kind of spaces, and
I do think, and that's why there's shielding provided
for the VCT operator, so that they're not exposed.
The spotter is up in a man lift,
so they're above that high, high radiation area,
so they're, and then the issue here was,
everybody else was moved to that low dose area.
As Eric mentioned, there were probably other places
on the pad that provided an unobstructed view
of the operation, and you could definitely leverage cameras,
video capability, to assist
in the oversight monitoring role.
- Absolutely.

- And I'm not sure, so going back to that,
Rachel, can you go back to the shield ring picture again?
And the question is, it looks like there's a gap
between the shield and the canister wall.
- Well, actually,
there has to be a gap between the shield ring
and the canister because you want the hot air,
that's being heated by the MPC, to be able to rise
to an exit through the top of the UMAX vault.
If you go to the lid picture, Rachel, if you don't mind.
You see the lid there, you have inlet vents
on the outer periphery of the lid
on all the low corners, those are inlet vents,
and they feed air to the outside of the divider ring,
that's cool air coming in.
That cool air travels down, it enters
into the MPC cavity, underneath the shield ring.
That air is heated by the MPC,
and it exits up, out through the top vent there,
and that's essentially the cooling
for the spent fuel in the storage canister,
while it's in the UMAX ISFSI vault.
So a gap is an integral part of that design.
- And, I don't, so the question, is turnover related
to radiation exposure at the site?
And I don't believe that's the case.
- I don't believe that to be the case, either.
Most of these, most of these people want to work,
and they mostly enjoy going to work.
So I don't think radiation's an issue out at,
for workers out at San Onofre,

I don't think that's a disincentive to, no.
- And it's said, there's a comment
about inspectors avoiding radiation
of downloading the canister into the vault,
and that was a consideration at San Onofre,
was the, was moving people to a low dose area.
I'm going to think inspectors here--
- Oversight.
- This actually refers to San Onofre,
or Holtec oversight staff.
And again, they want to minimize exposure, but you need
to minimize exposure while maintaining the correct level
of job oversight, so there's a balance between the two.
My inspectors, when they go out and watch these,
they're asked to go to the low dose waiting area,
but they go over there with the VCT operator,
and observe the downloading evolution up close
and personal, that's what they do, so,
to get a good understanding of what's going on,
and talk to people while they're doing the task.
And then we're back to the, hey, Rachel,
can you go back to the vault photo again?
So there's another comment about the quarter inch there,
where the gusset is. - I saw that.
- Yeah, so that is, that's just a fact of life
for San Onofre, there is a quarter inch,
about a quarter inch space there at the end of the gusset.
They need to account for that, train the staff,
and make sure that they're knowledgeable of it,
and do a better job aligning the canister,
before they do the download, and I think,
and at Callaway, they actually brought that gusset out

to the edge, so that, so that you didn't have
that same vulnerability, both designs are acceptable.
At Callaway, I think there's more forgiveness
to the, to the operators, at San Onofre,
you have to be more vigilant,
to make sure you get the initial alignment
of the canister correct, and that is definitely something
that's achievable and doable.
So there's a question about, is there any type
of quantifiable requirement by NRC
for qualifications of workers
and supervisors performing the work, so, in 10CFR72,
point, the qualification requirement, which is, what is it?
(overlapping)
Yeah, one of these, which one--
- It's 190. - 190.
So 10CFR72.190 requires a qualification program
for all individuals involved with important-to-safety tasks,
so these frontline workers here, that would involve the--
- VCT operator. - Okay.
- The guy responsible
for making sure the MPC is being downloaded properly.
- The spotter?
- The spotter into the vault, and it actually goes
onto other operations during fuel processing
inside of the fuel building.
So it's not just activities out on the ISFSI pad,
it's all of the quality related activities,
which includes things like welding,
on the placement of the fuel assemblies into the MPC,
into the lattice basket inside of the MPC.

All of these jobs are quality related, in dry fuel storage.

- Okay, and then if it's okay to use workers

that haven't completed the qualification process,

but they have to be directly accompanied by an individual

that has completed the qualification process.

- Correct.

- So, and that's why we, one of the reasons why we chose

to go with the qualifications violation,

was because you have people doing a task for the first time,

where the training program didn't get them

where they needed to be, and there wasn't a

supervisor, or somebody with the appropriate quals

right there with them during the job.

So Eric, I think one last time,

we'll talk about metal to metal contact,

and what our thoughts are on the significance

of that on a canister.

- Well, metal to metal contact isn't the best thing

to happen to a canister, however,

realize that in the case of MPC contact

with the divider shell ring, there is paint there,

that's designed to take these kind of scuffs,

and absorb some of that impact.

And Holtec is going to provide us with an analysis,

to give us the bounding conditions,

as far as scrapes and scratches that they think this

MPC number 29, installed in their ISFSI, experienced.

And I think that could be considered

to be a bounding analysis for all the other canisters,

because all the other canisters,

while they experienced a little bit of scuffing,

and a little bit of contact going into the ISFSI pad,

none of them actually hung up as MPC 29 did.
So, and then moving forward, we'll see how
that informs San Onofre's Aging Management Program,
how far they intend to go, as far as evaluating all
of their canisters for future degradation,
because, again, a scratch today isn't that big of a deal,
however, as time goes on, that could be a point
where stress corrosion cracking could initiate,
but again, those are all longterm concerns
on these canisters.
There are absolutely no immediate concerns regarding the
condition of the MPCs, and their ability
to perform their confinement function.
- And there's a question regarding radiation being an issue
to the folks that live within 50 miles of San Onofre,
and again, we'll just, one last time, the,
we don't think there's a radiological concern
with the ISFSI being located at San Onofre,
and as the fuel inside the canisters continues
to decay, there's less and less risk
of a zirconium fire, that's the principal driver to
what would be a radiological release,
and we don't think the conditions exist within a canister
to have a zirconium fire, because of the lack
of oxygen, and the wrong form of zirconium,
to propagate a fire, so we don't--
- And-- - Yeah?
- There's also another requirement
that San Onofre has to abide by,
and they've been abiding by this requirement for years.
It's the publishing

of a radiological environmental monitoring program report,
each and every year,
where they have TLD monitoring stations,
effluent monitoring stations,
monitoring stations onsite, as well as offsite.
And they're actively measuring the radiation impacts
of their facility on the surrounding environment,
and those reports are available in ADAMS,
they're publicly available in ADAMS,
and anyone in the Southern California area,
or anyone in the United States can go
to our agency-wide document system, and find these reports,
they are there, it's a requirement.
- And so there's a question about are, if,
whether or not San Onofre is going to use cameras
in the future to see into the vault during the downloading?
- All indications right now are yes,
but we'll see, when we perform our next inspection,
and see how they're engineering enhancements
and procedure enhancements are truly being borne out.
But all indications now are yes, they will be using cameras.
- And there's a question on, back on,
Rachel, slide 21, just so I have it for reference.
And there's a question about, what's actually paint?
Are the canisters painted?
- The canisters are not painted, however,
the divider shell that you're looking at in the webinar,
that is a painted surface, and if you look closely,
you can see, the paint has been scuffed off
by the contact this divider shell made with the canister.
- Yeah, so the canisters are stainless steel,
and then the divider plate is?

- Coated carbon steel.
- Coated carbon steel, okay. - I believe.
- All right. (inaudible)
Okay.
And there's a question about, why not have two spotters?
- That's a very good question, I think,
probably, moving forward, you're going to find certainly more
than one spotter, or more than one person
who has a vantage point out on the ISFSI pad,
during future downloading operations at San Onofre.
- All right, and if they, if they leverage cameras,
then you would be able
to have multiple people spotting the downloading evolution,
depending on the number and placement of the cameras.
So that, so there's a question
on the transfer cask cooling system,
so there's not a cooling system,
if you will, for the transfer cask.
This is for, so the fuel is maintained cool--
(overlapping)
We're talking about MPC 30 now, the one in the field,
though, so heat goes from the fuel assembly
to the helium gas to the canister wall--
- It's radiated out to the--
- It's radiated out to the transfer cask inner wall.
- And then to the environment.
- And then that's transferred through
the transfer cask shell, and then just the normal air
surrounding the transfer cask shell is
what dissipates that to the environment.
- Yes. - Okay.

And there's a question on the bottom of the canister,
and whether or not the weight of the canister,
sitting on that half inch gusset did more than scrape it,
it seems like there'd be a deformation at the bottom
of the canister, and that's one
of the key engineering evaluations we're waiting
to be provided with from San Onofre.
So we haven't, we haven't ruled out deformation,
but we're waiting to see the engineering analysis.
Our own experts think, if there was deformation,
it would be very minimal,
this is a three inch thick bottom lid,
and it would be minor deformation at most,
which would not have an impact on the canister integrity.
- So where do we find monitoring reports,
can you direct them to ADAMS, or?
- Yeah, so the licensee does the annual filing of the--
- Regional environmental--
- Of the environmental reports,
those should be available in a search of our,
of our public library, ADAMS, and you should be able
to pull that up, and in the prior years.
Is there an outside agency that monitors radiation levels,
or is only, or is it only left to Edison
to measure and report levels to the public?
- Well, there's one agency
that monitors radiation levels, it's the EPA,
they have their Environmental Radiation Monitoring Program,
however, the EPA program is sort of a voluntary program,
where they partner with universities,
and local interest groups, and they'll provide you
with a realtime radiation monitoring system.

Again, talk to your, whatever EPA region you're in,
and you can find out from them
where their closest monitoring station is.
It's actually called the ERAM system,
so maybe if you search on the EPA website for ERAMS,
you can find it, and it's a realtime monitoring system.
- And then, and then, just to make sure that,
that San Onofre is doing the right radiological surveys,
and monitoring, we have inspectors that go out,
and that's one of the things they look at each year,
they check those, the reports, the accuracy
of the reports, and they actually go out
with the technicians at the station,
and make sure they're actually taking the right measurements
from the right locations.
So that is, that process is validated and verified
by the NRC through direct inspection each year.
And then,
so the question is, the divider plate,
we keep talking about the vault picture, that's for
which location? - What do you mean?
- Which vault was that, vault number, do you remember?
- Oh, that was a picture I took during the dry runs out
at SONGS, September, 2017, just,
it's whatever vault they were downloading
into during the dry run when we were there.
- Okay, and the one with the paint scrape-age on it?
- That is the actually vault number 22.
- And that was for canister 29.
- For canister number 29.
- And if the canister was in there,

then how were we able to take a picture of that?

- That picture was taken by staff out at San Onofre.

- Okay.

- And they would have been able to take it

from the surface of the ISFSI?

- Yeah, and they can, they can take,

they can get a boom, and put a selfie stick or something--

- And zoom in on it. - Oh, yeah.

- Yeah. - Yeah.

- Okay.

- Or they could just have someone stand there.

- And so there's a question about cracking,

and cracking would allow oxygen to enter the canister,

again, we would expect the Aging Management Program

to detect, early detection of signs of cracking,

and then the cracks would be mitigated.

So we don't believe, and then, if it was a crack,

we're talking a very, very small opening.

If it did exist, it'd be small quantities of oxygen,

and you still don't have the right form of zirconium

to cause that spontaneous combustion, and have a,

to have that type of fire.

And there's a question about the,

when the canister was leaning onto the side

of the transfer cask, it's not three inches thick there,

it's something less. - Well, if.

Go ahead.

If you think about it, when the canister is leaning,

it is leaning, the very top edge

of the canister is going to be in contact

with the wall of the transfer cask.

And at that location, there's several layers of weld,

and actually, a nine inch thick shield plug,
which is the MPC lid, resting there.
So they're really, we really don't have
that many concerns about the confinement at that location.
- Yeah, where, it would have been leaning against the side
of the transfer cask, it's actually thicker than where it is
on the bottom of the MPC? - Yes.
(overlapping)
- And so there's a question, back on slide 21,
it seems to be our favorite slide today.
- Oh, okay.
- If, where's the canister, in relation
to where that picture was taken?
- Isn't that picture--
- You know, if you back up, that's right,
if you back up the slide, thank you, Patty,
if you back up to slide number 20, there's the canister.
- There's the canister, so you can see,
that is canister number-- - 29.
- 29, loaded,
and that's the gusset in question,
is directly above it, and that's about,
what is that, how many feet is that,
from the canister to the gusset?
- I couldn't tell you, but it looks like,
probably about a foot and a half.
- Okay. - Maybe.
- And then you could take that--
(overlapping)
- It's probably six to eight inches.
- All right, and you could take a picture of that,

either standing from the side, or from up above.

- You absolutely can because,

we're there when they're welding,

this lid that you're looking at right now, we're there

when they're welding that in, and we stand directly over it

to observe the welding operations,

and the NDE, when they install that.

Now, radiation levels can be very high there,

but you can go in and take a picture fairly quickly,

you don't have to linger around for too long.

And, again, that is absolutely the thickest portion

of this canister, it's nine inches thick,

just to provide shielding for those operations of welding.

- And then if, again, if there were early signs

of crack propagation, or crack indications,

we think the licensee would have time

to develop a repair strategy, and if it required removal

of the canister, it would be able to do that,

they'd have plenty of time to do that

before there was a significant impact on the canister.

- That's about right.

It's probably closer than that.

Go ahead (inaudible). - Yeah, and,

and I don't think today's panel is in a position to,

I wish we could give you an exact value

on the distance from top of the,

of the--

- MPC canister, to the top of the--

- To the lid, I just don't, yeah, we just don't have that.

This is one, I'm going to have Lee, who's one of my inspectors,

I'm going to have him flag that comment,

about how, you know, the shield ring to the top,

and the shield ring to the top of the canister,
and we'll see if we can't put something
in one of the FAQs about, that provides dimensions
of the storage vault.
There's a question on high burn up fuel, and how long it has
to stay in the pool before you can move it out, and I think.
- Those, those lengths of time have been changing,
it's new studies, I don't have that information.
- So will we get back to them for that one, too?
- No, I think there's, I'm not sure
what we prescribed, I think that the reference here is,
high burn up fuel require longer cooling time
than five years, before putting in the dry storage, and,
and I think five years is sufficient time
for decay purposes, prior to loading the, an MPC.
So I think that's okay, and in San Onofre's case,
they ceased operations (overlapping)
more than five years, it's been more than five years
since they've ceased operations, so they're okay
to move high burn up fuel into an MPC.
"If Slide 21 is of the
actual problem vault, why don't we see the canister,"
but we showed the canister.
- Yeah, and so, there, we received a lot
of questions throughout the course of the presentation,
on how long does it, how much time do you need
to build a hot cell, I don't have an answer for you.
That's something the licensee would have to do,
but there are, there are different ways
to do it, it could be brick and mortar,
it could be, you could move it into a,

a building, and then compensate with lead shielding,
and that would take less time,
so there's different alternatives out there,
so I don't, I can't give you a direct answer
on how long it takes to build a hot cell,
so it's very case dependent.
And any idea on the skin temperature
of a canister, loaded canister?
- We've seen it get close to 300 degrees,
a loaded canister, but that's, albeit,
after welding activities have taken place.
I think the hottest canister I've seen
on surface, maintaining the temperature,
is probably at 200, 235, 240 degrees, and--
- But what would be the hottest point of the canister,
would it be radially, or would it be top,
bottom, do you have a?
- Well, when I'm on top of the can,
it's usually at the welding point.
- Right.
- That's really hot, so I really couldn't tell you.
- Okay.
- And I haven't seen
fuel loaded at the top end of what's allowed, either.
- Right. - So.
- But normally, you'd see something in the 250
to 300 degree range? - Oh, yeah, yeah.
- And Patty, we have a question,
you talked about the shims before, right,
and so San Onofre does have four, I think it's four--
- It's four canisters--
- Canisters with the shim pins?

- Correct.
- So there's a question about those,
the canisters with the defective stand off shim pins.
Will they, will they withstand the weight
of a fully loaded can?
- Not really holding weight.
So the shim pins are on the shims, which are the,
they're along the,
okay, so the basket has a lot of square pieces in it,
and then there's, the canister is round,
so in those areas. (overlapping)
Oh, there we go. - Oh, there we go.
(overlapping)
- Basket in there, tight, so then we move around,
the shims, the
stand off pins are at the bottom of that,
to hold it off the bottom of the canister,
to leave some air space for the circulation
of the helium through the whole basket system.
- And, just to confirm, we were talking
in degrees Fahrenheit, not the.
- Not Celsius.
- Not Celsius, degrees Fahrenheit.
So,
are those scratches on the CEC,
with canister 29, and what's the whitish looking material?
- That's actually not the CEC, and,
it gets a little confusing when we begin
to talk about all these different terms,
and dry cask storage, especially with the UMAX ISFSI
because a storage vault actually consists of,

you mentioned the CEC, the cavity enclosure container.
That is the
stainless steel hole
that's in the concrete pad, inside of that hole,
they insert a divider shell, which provides the conditions
for continual cooling of the MPC.
So the divider shell is what we were looking at,
when we're looking at the scrapes and scratches.
The CEC is actually the outer wall, outside,
on the outside of that inner divider shell there.
- That white powdery material right there, what's--
- Oh, that's just--
- That's what we're talking about.
- Oh, that's just, that's residual cleaning fluid,
left over from the developer.
That white stuff you see on top of the MPC there,
that's probably left over developer
that wasn't properly cleaned completely off
of the welding when they performed the,
the NDE testing, if you look around the inside
of the ring there, there's an outer ring,
I can't explain this well for you
because I don't have a pointer.
But that is probably just cleaning
that was done incompletely, that's right, that's right.
That's what that white stuff, that's what it looks like
to me, but I wouldn't be concerned about that at all.
- That's something that they would eventually clean off,
before they put the closure lid on?
- I don't think so, in this case, no.
- All right, okay.
While we're waiting for more questions

from my staff back there, for those
that are still, still with us on the webinar, if you,
that have hung in for I guess almost two and a half
or so hours now, if you have comments regarding
the webinar itself, and did it help you be a,
participate in learning more about this event,
and the NRC activities, if you want to provide feedback
on that, that'd be great, if you could just add them
to the, to the chatroom,
and then we'll take that feedback, and
see if we can't make the next one better.
So there's a question about, about the NRC allowing
promises, I'm not going to, or commitments, I'll say,
from a licensee, to figure out how to inspect,
repair, retrieve fuel, and inspect fuel,
to be a strong regulatory framework.
And so we've established a regulatory framework
that we think, that we believe provides
for the safe storage of spent fuel at San Onofre,
and we think the requirement,
to have the Aging Management Program,
goes a long way, in the early detection of,
of deficiencies that allows sufficient time
to complete the repair, and so we think
that provides an appropriate regulatory framework
for the licensee.
And so I have, I have,
there's a question regarding comparing procedures
at San Onofre with that of other licensees,
or training programs, and
I have two inspectors in Region IV, Eric and Lee,

and that's one of the things that they do,
when they go from site to site,
is they're able to compare and contrast the adequacy
of different programs, from one licensee to another.
- And I can tell you that the real difference is not
in the quality of the procedures from site to site,
the true difference in a dry cask storage program is
how the licensee, that is the utility,
how engaged they are in dry cask loading operations,
how engaged they are,
are they out performing deck plate oversight,
or are they sitting back in an office someplace, you know?
That's the real difference in dry cask loading operations,
is just how involved the licensee is going to be,
how intrusive they're going to be.
NRC is only going to be there for one can
of a loading campaign. They are there
for all the cans, and they need
to be out there providing deck plate oversight,
looking over the welders' shoulders
when they're doing welding, they need
to be out there watching dry cask storage operations out
on the pad, or when they're downloading into a HISTORM,
or any other type of overpack, that is the difference.
That is the difference between a good program
and a program that doesn't perform so well,
that is the difference, in a nutshell, and that is
what we see when we're out inspecting these licensees.
- And there's a question on, again, on
requiring licensees to do drop analysis,
and,
and how the public can intervene

to require that a licensee does some type of drop analysis,
and so, so as of now, the NRC believes
that the drop analysis is not required,
not for this type of event, that exists at San Onofre,
because the ultimate requirement is
to maintain the redundant load drop protection.
And so we don't plan to require a change
to the final safety analysis report
to include the, a load drop event.
That said, that the public always has the right
to petition the NRC, through the petitioning process, to
impose additional requirements on licensees.
And if you choose to do that, you can,
you can follow the NRC's program for that,
and ask the NRC to reconsider their decision
on when a drop analysis is required.
And then the question on how can the licensee inspect,
or monitor canisters?
- Oh, (inaudible) inspect or monitor the canisters?
So I had mentioned,
I don't know, it's,
EPRI, the Electric Power Research Institute,
did some studies to kind of help industry figure out methods
of doing their Aging Management inspections,
and they put, what I mentioned before,
these crawlers that you see they have,
either keep, you know, (inaudible) for a camera,
or other non-restrictive
examination equipment to go,
depending on what kind of system it is,
you know, the cases around the canister,

to be able to go through close to, like,
the annulus to go through and see,
or there's other probes, not maybe crawlers all the time,
and they were testing these, they did a few tests
that the NRC sent, we sent one inspector,
and one technical reviewer to,
to watch their testing, and they did.
We've also gone out to a number of facilities
that were preparing for their renewals,
and they did, they brought out whatever pieces
of equipment that they were going, that they were planning
on using in their Aging Management Program,
just to test those out, to see if those were going to be useful
when they actually had
to do their Aging Management inspections.
So usually, it has to do with some sort of probe,
or crawler that goes along the annulus,
and looks at sides of the canister.
- And this, and the use of robotic technology
to do non-destructive examinations
at nuclear power plants, and else,
and other industries, that's, that's not new technology,
that's been around for awhile,
and so we're just taking advantage of the technology
that already exists in the US,
and applying it to multipurpose canisters.
There is no requirement to do an inspection
on the inside of the multipurpose canister,
these are all inspections that are done external
to the surface of the canister.
And I know we're getting a lot of comments
about hot cell construction,

and the NRC does not require licensees to maintain a pool,
or to maintain a hot cell structure for,
for retrieving fuel from a multipurpose canister,
or some other canister, should the need arise.
They do have to have the ability to,
to perform that, and we don't think that it's a,
an immediate or rapid type of inspection to meet.
So you would have early detection,
you have the ability to construct the facility you need,
and there'd be ample opportunity to,
to make those repairs, and at this time,
we don't have any requirements imposed
on licensees to maintain either type of facility,
pool or hot cell, again,
I understand that there are probably a wide assortment
of views on whether that should be imposed
on licensees, and that, and if you feel strongly about that,
this is where'd you want to avail yourself
of the NRC's petition process, and,
and send it to the NRC for consideration.
So there's a question that says,
given that Edison created this fuel under the impression
that there would be a national repository,
would you consider it fair for Edison
and other companies to be getting national assistance
for help for maintaining safe procedures
and monitoring systems for this fuel?
And.
- So that,
so those that were required to,
the acceptance of, for the disposal of the fuel was,

was Department of Energy's task,
and yes, they do not currently have a repository
for disposal, I believe there are some facilities
that are tapping DOE for some funding,
for some of the operations that they're doing,
with their spent fuel, I'm not certain, as I'm not,
I don't look at that directly,
but I'm not certain what they've been approved
to get funding for, but it's up to the Department of Energy,
and whatever their responsibilities were,
and what the licensee is doing,
whether those items could be reimbursed or not.
- Right, right-- - So there is a small part,
that they are getting reimbursed--
- Okay, and of course, with the appropriate legislation,
Congress could dictate that that happen, as well.
- Correct, yeah.
- And says, how much longer will loading take at San Onofre?
- Probably another year, once they start,
a year or less, is my best guess.
- And then there's a comment that says,
in the case of San Onofre, there's no room
for cameras, or other actual ability to do any other checks,
after loading into the vault?
And so, and so I think actually San Onofre is looking
into that, and there is, my understanding is,
the robotic technology is such that you can get a crawler
into the storage vault, and do the inspections at,
of a canister at San Onofre.
And it's also my understanding
that the robotic technology being deployed today
is using the, an eddy current testing methodology,

and that that's, that has,
that's proving to be sufficient at checking
for crack initiation,
and that's why we,
the testing has been going on with EPRI at some
of the sites, to fine tune and work out a solution
for everybody to follow.
And then there's a question
about how involved has Edison been
in the oversight of moving waste.
- Well, one of their corrective actions is,
they're going to be much more involved than they were,
prior to this event, that's for sure.
- That, one of our concerns that we've communicated,
and it's been identified in the root causal evaluations
by San Onofre, is they weren't as involved
in the contractor oversight at the facility
as they should have been, they recognized that,
and many of their corrective actions that they're,
that they're developing now involve
building up that contractor oversight.
So it's important to us that they get it right
for Holtec during the, when they resume fuel handling,
and it's important that they get it right
for their decommissioning contractor, before they
start significant decommissioning work at the site.
- That's a good question.
- And so I'm going to skip down the, Patty,
if the shim pins all break, in the affected canister,
would there still be adequate cooling of the canister,
if the shim pins were all snapped off?

- I don't know if we have an analysis of that.

- A final analysis?

- Yeah, a final analysis.

- Yeah, I think the early analysis said

that there was adequate cooling of the canister,

even with broken shim pins-- - Right.

- For the fuel that's currently loaded,

affected-- - For the fuel

in the affected canisters. - That's right.

- That we believe that there's still adequate cooling

of the canister,

so, but I also recognize

that there's more engineering evaluation continuing

on that question, but we didn't believe

that there was an issue, based on our own evaluations.

And so there's a question, I guess, I don't know.

(inaudible)

And so there's a question on, if the canister dropped,

and the containment boundary breached,

what's the worst case, and again,

for the scenario at San Onofre,

if this canister had dropped the distance of 18 feet,

into the storage vault,

we don't believe there would have been a major loss

of the containment boundary.

So there wouldn't have been

a significant radiological impact from a canister drop.

So the worst case scenario

would be some cracking

of the weld of,

of the MPC,

and the release,

via cracking of a weld of an MPC, if,
would be marginal, it would be very small.
So I don't think there would be
a significant radiological hazard, that,
that keep, with that said, that is one of those evaluations
that we are waiting for, giving the licensee the opportunity
to complete that, and then,
and then we're going to take a look at that,
do our own independent engineering look at
that evaluation, and reach our own assessment
of what the consequences could have been.
I think we're in the five minute range,
left on the webinar, is that about right,
in the back of the room, okay.
So why is the mesa not being discussed for safer storage?
- You mean the big bluff overlooking the ISFSI--
- No, mesa, on the other side of the freeway, where the,
where the training building, there were some warehousing,
over on the other side of the freeway,
why isn't that being considered,
why wasn't that considered for the ISFSI pad location?
- Well, actually, the NRC doesn't decide
where it's going to be, it's the licensee who decides.
They propose, they give us all of their analysis,
and we review that, so it's based on what,
where they were identifying it would go.
- Okay, and so, and then our role is to,
when presented with the location that they wanted,
is it a safe location, we determined
that met our requirements for, for placement
of an ISFSI pad, so.

So there's a question about,
what are the internal mechanisms in the NRC
to identify opportunities for improvement
from this and other situations,
where licensee has multiple violations?
Who's in charge of thinking about those questions,
and how do corrective action programs occur
within the NRC itself?
So the,
in the San Onofre case,
what we've done is, we've taken the learning
from our inspection activities at San Onofre,
and what actually happened,
and we've been providing operating experience
and knowledge management,
knowledge transfer briefings throughout the NRC.
And one of the next steps we have to do is
to take the presentation we've provided today,
and offer it up to the other regional offices
and program offices at headquarters,
and brief them on the event, our learnings,
and where we think there might be areas
to improve within the inspection program.
So that's done, at least within my division,
that's done as a matter of routine.
If we go out and find significant issues
with the licensee, we come back,
we talk about it with the whole division,
and if we think those learnings are generically applicable
to the inspection program, we seek inspection program change
to get it right.
Is what, is the ISFSI site for indefinite use?

I think Eric, talk--
- It's safe for indefinite use.
- I think Eric talked about this before,
so it's initially licensed for 20, and--
- Can be re-licensed for 20 or 40 years.
- 20 or 40, we think it's good to go
for up to 100 years-- - The canister.
- The canister. - The canister.
- Yeah. - Yeah, for 100 years.
And, and the NRC believes that,
that there'll be a, within the next 100 years,
there'll be a solution for longterm waste disposal
of high level waste.
And I think we're down to a couple of minutes,
I do want to thank those that have hung on this long
to participate, I really appreciate the use
of the chatroom features, and all the dialogue
and questions that came into the chatroom for the,
for the panel to respond to.
We do plan to go back through the chatroom comments
and questions, and scrub them some more,
and where we find things that we didn't address today,
or we don't think we did a good enough job addressing,
then we'll collect those, we'll likely add those
to our frequently asked questions document
on the NRC Spotlight, underneath the San Onofre tab.
So the dialogue is, I view this as,
the dialogue has just begun,
this is not a one and done opportunity.
If you think this forum was useful,
we'd like to do it again, we have another inspection activity

and corrective actions coming up
in early mid-December timeframe,
I think, you know, this is-- - If all goes to schedule.
- You know, if desired, this,
that might be a good opportunity to,
to use this forum again, to brief out to the public
on what we found, and why, you know, if we make a decision
to resume fuel loading, that we can communicate
that with you, what the basis of our decision is.
- That's the last question.
Is it over?
- Okay, so I think we're going to,
to wrap up the webinar, again, thanks to everybody
that joined and participated, have a good evening.
- Thank you.

EXHIBIT 14

Dr. Kris Singh

CEO Holtec International

Event: Southern California Edison's Community Engagement Panel (CEP)

Location: San Juan Capistrano, CA

Date: 2014-10-14

31:04 to 34:30

Panel Member Gene Stone: Yes, so, another question I had was, on your map you showed that you had your products being used in several different countries. Do any of the European countries, or Asian countries, you know, are they using a, are your materials that are underground, are they covered by a building as well, to protect from external weather conditions?

Dr. Singh: Yeah, in Europe there's a misconception. Europeans put their casks inside buildings. The reason they so that, it's been a historical practice, because, they don't have, you know, huge land mass sites. Here you go to a nuclear plant it's bigger than Luxembourg, some sites. You know . . .

Chairman David Victor: Not to disparage Luxembourg.

Dr. Singh: You go to Europe and you see people living in apartments, you know, right outside the fence. So they, to deal with people, people's sensibilities, they put a structure around it. Most of these structures are not seismically qualified to Californian earthquakes. There are cranes that they use are not single failure proof cranes. They basically, it's more of an optical protection than it's a safety protection. And that's the practice that's been in Europe forever. It's not a, this is not something that we need to be copying here. You don't really gain anything. Yeah, of course we should not go inside the canister. You don't breach the confinement integrity to be monitoring for breach of confinement and integrity. But there is, there is a, a direct way, at least in our canister, to see if you if you are getting any, getting any breach of the wall. The canister, and you saw, in the slide, the helium circulates, and it makes the lid hot. This lid on our canister is quite hot. We imbed a thermocouple, in the lid, and you can see the temperature fluctuation. If you had loss of helium, that temperature will drop. So…

Chairman David Victor: I bet you learn a lot from the temperature.

Dr. Singh: You learn just by metal temperature, not by air temperature. Metal temperature is very sensitive. And in our thermally circulating, helium circulating canister there's a direct way to measure what's going on, on the inside, without breaching the wall.

Well, in, in my personal belief, it's not practical to repair a canister, if it were damaged. If it had a through-wall damage, first you prevent it, but, in the most unlikely circumstance, if that canister were to develop a leak, let's be realistic, you have to have find it, that crack, where it might be, and then find the means to repair it. You will have, in the face of millions of curies of radioactivity, that is coming out of the canister, we think it's not [unintelligible]. However, let, let me, uh, you can easily, easily isolate the canister in a cask that keeps it cool and basically you've provided a next confinement boundary, and you're not relying on the canister. So, that it a practical way to deal with it, and that's the way we advocate for our clients.

EXHIBIT 15

MIKE LEVIN
49TH DISTRICT, CALIFORNIA

WASHINGTON, DC 20515
(202) 225-3906

Congress of the United States
House of Representatives
Washington, DC 20515–0549

June 11, 2019

The Honorable Kristine Svinicki
Chairwoman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Chairman Svinicki,

I write to follow up on my letter to you dated April 15, 2019, calling for a full-time inspector to be assigned to the San Onofre Nuclear Generating Station (SONGS). The letter, sent nearly two months ago, was signed by both of California's Senators and five Members of Congress whose constituents are directly impacted by your oversight responsibilities at SONGS. We have yet to receive a written response from you or any other Nuclear Regulatory Commission (NRC) official. This lack of response is particularly concerning in light of the Commission's May 21, 2019, determination allowing Southern California Edison and Holtec International to resume spent fuel loading.

On June 7, 2019, the House Oversight Committee held a hearing that I participated in examining federal spent nuclear fuel policies and safety at SONGS. NRC Region IV Administrator Scott Morris testified on behalf of the Commission. During the hearing, Administrator Morris confirmed that the following facts about occurrences at SONGS over the last year:

- The August 2018 "near-miss" incident at SONGS was caused by deficiencies in Southern California Edison's training, equipment, procedures, and oversight.
- Southern California Edison's staff at SONGS were not properly trained, certified, and supervised.
- Southern California Edison failed to formally report the August 2018 "near-miss" incident within the timeframe required by the NRC.
- A similar event had previously taken place at SONGS, but Southern California Edison did not take corrective action to ensure such an event would not happen again.
- The August 2018 "near-miss" and reporting deficiencies led to the NRC assessing Southern California Edison with a Level II violation.
- It is not common for NRC licensees to receive Level II violations.
- Southern California Edison inspected only eight of the 29 canisters that have been downloaded into the independent spent fuel storage installation (ISFSI) at SONGS.

Administrator Morris's testimony further illustrated the extraordinary record of non-compliance at SONGS. Southern California Edison's violation stemming from its failure to report the August 2019 "near-miss" in a timely manner demonstrates that the Commission cannot rely on its licensee to self-report. As such, periodic inspections are inadequate to provide local communities the level of safety and transparency that they deserve. With this in mind, I reiterate my call for a

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full-time inspector to verify that all spent fuel loading activities at SONGS comply with NRC safety requirements.

Additionally, I was disappointed to learn that Southern California Edison and the NRC visually assessed only eight of the 29 loaded canisters at SONGS. The facility's location presents unique environmental threats and elevated hazard to canister integrity, including seismic activity and corrosive ocean air. Southern California Edison has informed me that it costed approximately $400,000 in total for the eight visual inspections. The cost of additional inspections is a small price to pay for greater certainty about canister conditions, especially given the $4.7 billion price tag for the decommissioning of SONGS.[1] I urge you to immediately require the visual inspection of the remaining 21 canisters.

Please provide a response to this letter no later than June 24, 2019. Thank you.

Sincerely,

Mike Levin

MIKE LEVIN
Member of Congress

[1] Sforza, Teri. 30 April 2018. "How much should it cost to pay for San Onofre nuclear plant's shutdown? Here's how you can weigh in." *The Orange County Register*.

CC: Scott Morris, Administrator, Region IV, U.S. Nuclear Regulatory Commission

MIKE LEVIN
49TH DISTRICT, CALIFORNIA

1626 LONGWORTH HOUSE OFFICE BUILDING
WASHINGTON, DC 20515
(202) 225-3906

Congress of the United States
House of Representatives
Washington, DC 20515–0549

June 21, 2019

The Honorable Kristine Svinicki
Chairwoman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Chairman Svinicki,

Thank you for agreeing to meet with me in the coming weeks regarding the San Onofre Nuclear Generating Station (SONGS), located in my Congressional district. I look forward to a thorough discussion of the Nuclear Regulatory Commission's (NRC) decisions regarding safety at SONGS. While I am sure that our conversation will be valuable, it is my understanding that Southern California Edison (SCE) may plan to resume the loading of spent fuel canisters prior to our meeting. With this in mind, I feel it is important that I voice my concern with the NRC's repeated decisions that fail to maximize safety and transparency at SONGS.

The NRC's mission statement clearly affirms that the Commission has a responsibility to provide "adequate protection of public health and safety."[1] As I look back at recent incidents at SONGS, I see a record that demands greater NRC intervention. That record includes the following:

- Falsified fire safety recordkeeping.[2]
- Failed backup power systems.[3]
- Backlash against employees who reported poor safety practices.[4]
- An NRC review that found SCE's corrective actions had "not resulted in sustained and measurable improvement" of human performance onsite.[5]
- Unexpected degradation of new steam generators, an incident that was incorrectly dismissed as minor.[6]
- A radioactive leak that resulted in the shutdown of a reactor.[7]
- The discovery of loose bolts in spent fuel canisters.[8]

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[1] About NRC. *U.S. Nuclear Regulatory Commission.* https://www.nrc.gov/about-nrc.html.
[2] Woodall, Bernie. 14 Jan. 2008. "So. Calif. nuclear plant worker faked fire checks." *Reuters.*
[3] Douglass, Elizabeth. 31 July 2008. "San Onofre under scrutiny." *Los Angeles Times.*
[4] Sisson, Paul. 17 Nov. 2008. "SAN ONOFRE: Workers allege retaliation for raising safety concern." *San Diego Union-Tribune.*
[5] Bermudez, Esmerelda. 5 Feb. 2012. "San Onofre nuclear power plant incidents draw attention." *Los Angeles Times.*
[6] Sewell, Abby and Ken Bensinger. 13 July 2013. "How San Onofre's new steam generators sealed nuclear plant's fate." *Los Angeles Times.*
[7] Bermudez, Esmerelda. 5 Feb. 2012. "San Onofre nuclear power plant incidents draw attention." *Los Angeles Times.*
[8] Sforza, Terry. 29 Mar. 2018. "Here's how the bolt on the container of nuclear waste at San Onofre may have been shaken loose. *Orange County Register.*

- A "near-miss" incident that could have resulted in the 18-foot drop of a spent fuel canister.[9]

These incidents still loom large in the consciousness of my constituents who live near SONGS. They hear about how the most recent "near-miss" was caused by deficiencies in SCE's training, equipment, procedures, and oversight, and they see how the incident fits into a larger pattern of behavior.

I would like to be able to tell my constituents that they should be comforted to know that the NRC is genuinely committed to protecting their safety. However, a review of your recent record fails to provide that comfort. After you found SCE had committed a Level II violation, a violation level that NRC Region IV Administrator Scott Morris called "uncommon," you only assessed a $116,000 civil penalty on a company with assets totaling more than $56 billion.[10] In response to unplanned scratching on the surface of the spent fuel canisters at SONGS, you required SCE to visually inspect only eight of the 29 loaded canisters onsite, despite the minimal incremental cost of additional inspections.[11] Finally, you have decided it is unnecessary to assign a full-time inspector to SONGS while being aware of the dubious record at the site and knowing how such an action would help to rebuild the public trust.

Further, your justification for refusing to assign a full-time inspector to SONGS does not seem to account for the unique loading campaign that SCE intends to conduct. In your June 17, 2019, letter to me, you state that canister loading activities "are usually limited in duration." However, NRC Region IV staff has confirmed that SCE will be carrying out an ongoing, accelerated decommissioning that is significantly different than the process by which most utilities transfer spent fuel. NRC Region IV staff has acknowledged that the accelerated decommissioning presents unique challenges and can be more difficult than a standard decommissioning.[12]

Given the noteworthy nature of the spent fuel transfer campaign at SONGS, I urge you to assign an inspector to SONGS at all times that fuel transfer activities are taking place. Please respond to the following questions related this proposed inspection regime:

- Do you have the statutory authority to assign an inspector to SONGS at all times that fuel transfer activities are taking place? If you do not, please describe the authorities you would need in order to do so.
- Do you have funding available to assign an inspector to SONGS at all times that that fuel transfer activities are taking place? If you do not, please provide the estimated cost of this inspection regime.

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[9] Nikolewski, Rob. 10 Aug. 2018. "Incident with waste canister at San Onofre nuclear plant prompts additional training measures." *San Diego Union Tribune.*
[10] 2018 Annual Report. *Edison International.* https://www.edison.com/content/dam/eix/documents/investors/corporate-governance/eix-sce-2018-annual-report.pdf
[11] NRC Region IV Phone Call with Congressional Staff. *31 May 2019.*
[12] Ibid.

Each incident at SONGS listed in this letter was thought to be the last after they became public. You have a responsibility to take every action available to minimize the chance of future incidents. I would be incredibly disappointed if history repeats itself.

I look forward to further discussion at our meeting.

Sincerely,

Mike Levin

MIKE LEVIN
Member of Congress

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

CHAIRMAN

July 16, 2019

The Honorable Mike Levin
United States House of Representatives
Washington, DC 20515

Dear Congressman Levin:

On behalf of the U.S. Nuclear Regulatory Commission (NRC), I am responding to your letters of June 11 and June 21, 2019, expressing concerns related to the San Onofre Nuclear Generating Station (SONGS).

I very much appreciated the opportunity to meet with you on July 11th to discuss in greater detail your concerns. I agree with you on the importance of accountability to ensure the safety of the people in the communities surrounding SONGS, and am committed to continued communications with you on this issue.

As I mentioned during our conversation, I am confident that the NRC's inspection plan for the SONGS decommissioning process is the most effective approach to ensure the safe decommissioning of the site. We have extensive experience and a proven record with performing inspections at decommissioning sites, and the NRC's inspectors who perform this function are experts with extensive experience in this area. In addition, I want to assure you that we will not hesitate to devote the inspection resources necessary to ensure the safe decommissioning of SONGS.

Thank you again for your time and the opportunity to discuss the NRC's inspection and oversight of these activities. Please feel free to contact me or have your staff contact Eugene Dacus, Director of the Office of Congressional Affairs, at 301-415-1776 if you have additional questions or need more information.

Sincerely,

Kristine L. Svinicki

EXHIBIT 16

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

August 17, 2018

MEMORANDUM TO: Eric J. Simpson, CHP, Health Physicist
Fuel Cycle and Decommissioning Branch
Division of Nuclear Materials Safety

W. Chris Smith, Reactor Inspector
Engineering Branch 1
Division of Reactor Safety

Marlone X. Davis, Transportation & Storage Safety Inspector
Inspections & Operations Branch
Division of Spent Fuel Management

THROUGH: Janine F. Katanic, PhD, CHP, Chief /RA/ LLH for
Fuel Cycle and Decommissioning Branch
Division of Nuclear Materials Safety

FROM: Troy W. Pruett, Director /RA/
Division of Nuclear Materials Safety

SUBJECT: INSPECTION CHARTER TO EVALUATE THE NEAR-MISS LOAD DROP EVENT AT SAN ONOFRE NUCLEAR GENERATING STATION

A special inspection has been chartered to review the licensee's follow-up investigation, causal evaluation, and planned corrective actions regarding the near-miss drop event involving a loaded spent fuel storage canister at the San Onofre Nuclear Generating Station (SONGS) Independent Spent Fuel Storage Installation (ISFSI) on Friday, August 3, 2018. (License Nos. NPF-10 and NPF-15, Docket Nos. 50-361, 50-362 and 72-41).

CONTACT: Janine F. Katanic, PhD, CHP, FCDB/DNMS
(817) 200-1151

BACKGROUND AND BASIS

On Friday, August 3, 2018, at approximately 1:30 pm (PST), SONGS was engaged in operations involving movement of a loaded spent fuel storage canister into its underground ISFSI storage vault (HI-STORM UMAX storage system). As the loaded spent fuel canister was being lowered into the storage vault using lifting and rigging equipment, the licensee's personnel failed to notice that the canister was misaligned and was not being properly lowered. The licensee continued to lower the rigging and lifting equipment until it believed that the canister had been fully lowered to the bottom of the storage vault. However, a radiation protection technician identified elevated radiation readings that were not consistent with a fully lowered canister. The licensee then identified that the loaded spent fuel canister was hung up on a metal flange near the top of the storage vault, preventing it from being lowered, and that the rigging and lifting equipment was slack and no longer bearing the load of the canister.

In this circumstance, with the important to safety (ITS) rigging and lifting equipment completely down in the lowest position, the ITS equipment was disabled from performing its designed safety function of holding and controlling the loaded canister from a potential canister drop condition. The licensee reported that the canister was resting on a metal flange within the storage vault. It was estimated that the canister could have experienced an approximately 17-18 foot drop into the storage vault if the canister had slipped off the metal flange or if the metal flange failed. This load drop accident is not a condition analyzed in the dry fuel storage system's Final Safety Analysis Report (FSAR).

In response to the discovery that the canister was not fully lowered, the licensee took immediate actions to restore control of the load to the rigging and lifting devices. The estimated time the canister was in an unanalyzed credible drop condition was approximately 45 minutes to 1 hour in duration. The licensee regained control of the load, repositioned the canister, and lowered the canister into the storage vault. The licensee halted all dry fuel storage movement operations in order to fully investigate the incident and develop corrective actions to prevent a recurrence. In addition, the licensee has shared the operational experience with another site with a similar dry fuel storage system.

Region IV became aware of the SONGS "near-miss" incident on Monday, August 6, 2018, when the licensee provided a courtesy notification and described it as a "near-miss" or "near-hit" event. The reporting requirements of the incident are still being evaluated by the Region and discussed with the licensee.

On August 7 and 16, 2018, Region IV and NMSS representatives participated in conference calls with licensee representatives in order to gather additional facts regarding the circumstances of the incident and the licensee's investigation. Region IV is evaluating the information provided by the licensee and is coordinating with the Division of Spent Fuel Management, NMSS.

The NRC is chartering this special inspection pursuant to Management Directive 8.3, "NRC Incident Investigation Program," and NRC Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors."

The purpose of the inspection is to investigate the occurrence; interview personnel; observe equipment; and review relevant documentation, including the results of the licensee's investigation and causal analysis, and development and implementation of actions to prevent

recurrence. The licensee has committed to not resume fuel loading operations until after this special inspection and associated reviews are complete. Once the licensee has confirmed its plans to resume fuel loading operations, inspectors will also observe the loading operations to ensure that the corrective actions are adequate. These observations may be conducted as part of this special inspection or as an independent inspection activity, as directed by regional management.

SCOPE

The inspection should seek to address the following items at a minimum:

1. Identify and review all pertinent records, documents, and procedures related to the licensee's downloading operations at the ISFSI pad including but not limited to: worker training and qualifications; rigging equipment qualification, testing, and preventative maintenance; and lifting equipment qualification, testing, and preventative maintenance. Evaluate the adequacy of the above noted procedures, worker training and equipment testing and preparation.

2. Evaluate the adequacy of the loading procedure(s) with respect to verification of MPC movement, centering the MPC over the ISFSI vault, lowering the MPC, and positioning the MPC within the ISFSI vault. Interviews with personnel involved in the ISFSI loading operations should be conducted to evaluate licensee and contractor communications between crane/VCT operators, rigging and spotting staff, cask loading supervisors, radiation protection staff, and licensee oversight personnel. Evaluate the adequacy of pre-job briefings that may have taken place prior to fuel loading operations.

3. Review and evaluate the licensee's immediate corrective actions taken after the event for adequacy of notifications to the licensee and safety assessments performed immediately following the event. Review the licensee's inspection documentation and/or analysis to determine whether the vault's divider shell experienced any damage that would inhibit the component from performing its designed safety function.

4. Based on the review of procedures and interviews of personnel involved with loading operations, evaluate the adequacy of procedure adherence.

5. Interview personnel associated with the event to develop a timeline to ensure the licensee's investigation contained all necessary information to identify all contributing factors and develop adequate corrective actions.

6. Review the licensee's root cause investigation results, to determine whether the review thoroughly identified all contributing factors and that final corrective actions will be adequate to prevent reoccurrence. Evaluate whether prior operational experience relating to complications or issues associated with canister downloading operations was identified and considered as part of the licensee's root cause investigation and corrective action development.

7. Review the licensee's planned actions that will address the point loading condition that was experienced by the affected canister. If applicable, review the licensee's analysis that demonstrated the canister will continue to perform as designed for continued storage OR review licensee's inspection plan to safely remove or lift the canister from the vault to support inspection of the bottom of the canister to demonstrate the canister did not

receive any damage that would inhibit the component from continuing to perform as designed.

8. Investigate the licensee's procedures for reportability to the NRC and determine if the licensee made the correct decision regarding notifications made to the NRC for this event.

9. As directed by regional management, observe resumption of fuel loading operations to verify that corrective actions were effective in addressing deficiencies that contributed to the event. This should include evaluation of procedure and/or equipment enhancements; review or observation of training and briefings provided to riggers, crane operators, spotters and observers, supervisors and other personnel involved in fuel loading operations.

10. Determine if the inspection should be elevated to an AIT and promptly notify regional management of any recommendation to escalate the special inspection to an AIT.

GUIDANCE

The NRC is chartering this special inspection pursuant to Management Directive 8.3, "NRC Incident Investigation Program," and NRC Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors." The Manual Chapter and Management Directive identify Inspection Procedure 93812, "Special Inspection," for specific use in reviewing events. Planned Dates of Inspection are September 10-14, 2018.

This inspection should emphasize fact-finding in its review of the circumstances surrounding the near-miss canister drop event. Safety concerns identified that are not directly related to near-miss drop event should be reported to NRC management for appropriate action.

Daily briefings with NRC management should occur to discuss the team's progress and preliminary observations.

In accordance with Manual Chapter 0610, a report documenting the results of the inspection should be issued within 30-45 days of the completion of the inspection.

This Charter may be modified should NRC inspectors find significant new information that warrants review. Should you have any questions concerning this charter, please contact Janine F. Katanic at 817-200-1151.

INSPECTION CHARTER TO EVALUATE THE NEAR-MISS LOAD DROP EVENT AT SAN ONOFRE NUCLEAR GENERATING STATION – DATED AUGUST 17, 2018

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ADAMS ACCESSION NUMBER: ML18229A203

■SUNSI Review By: LLH	ADAMS: ■ Yes ☐ No	☐ Non-Publicly Available ■ Publicly Available	■Non-Sensitive ☐ Sensitive	Keyword: NRC-002

OFFICE	DNMS:FCDB	DNMS:DD	DNMS:D
NAME	JFKatanic	LLHowell	TWPruett
SIGNATURE	*/RA/ LLH for*	/RA/	/RA/
DATE	8/17/18	8/17/18	8/17/18

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EXHIBIT 17

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BOULEVARD
ARLINGTON, TEXAS 76011-4511

March 25, 2019

EA-18-155

Mr. Doug Bauder, Vice President
and Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $116,000 AND NRC SPECIAL INSPECTION REPORT 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001

Mr. Bauder:

This letter refers to the special inspection conducted on September 10-14, 2018, at your facility in San Clemente, California. The inspection was conducted in response to the misalignment of a loaded spent fuel storage canister as it was being downloaded into the storage vault at the San Onofre Nuclear Generating Station (SONGS) on August 3, 2018. A final exit briefing was conducted telephonically with Mr. Thomas Palmisano and members of your staff on November 1, 2018, and the details regarding two apparent violations were provided in the subject inspection report dated November 28, 2018, NRC's Agencywide Documents Access and Management System (ADAMS) Accession ML18332A357. An errata to this inspection report was issued on December 19, 2018, ADAMS Accession ML18341A172.

In the letter transmitting the inspection report, we provided you with the opportunity to address the apparent violations identified in the report by either attending a predecisional enforcement conference (PEC) or requesting alternative dispute resolution (ADR). On December 10, 2018, SONGS staff informed the NRC that they requested a PEC. On January 24, 2019, a public PEC was conducted in the Region IV office with you and members of your staff to discuss the apparent violations, their significance, their root causes, and your corrective actions.

Based on the information developed during the inspection and the information that you provided during the PEC, the NRC has determined that two violations of NRC requirements occurred. The violations are cited in Enclosure 1, Notice of Violation and Proposed Imposition of Civil Penalty (Notice), and the circumstances surrounding them are described in the subject inspection report. Violation A involved the failure to ensure that important-to-safety equipment was available to provide redundant drop protection features for a loaded spent fuel canister during downloading operations. Violation B involved the failure to make a timely notification to the NRC Headquarters Operations Center for the August 3, 2018, disabling of important-to-safety equipment.

The NRC considers that Violation A could have resulted in a significant safety consequence because an important-to-safety feature was disabled during a spent fuel canister downloading operation. Therefore, this violation has been categorized in accordance with the NRC Enforcement Policy at Severity Level II. The NRC considers that Violation B impacted the NRC's ability to perform its regulatory oversight function. Therefore, this violation has been categorized in accordance with the NRC Enforcement Policy at Severity Level III.

Because Violation A was associated with a Severity Level II violation, the NRC considered whether credit was warranted for *Identification* and *Corrective Action* in accordance with the civil penalty assessment process in Section 2.3.4 of the NRC Enforcement Policy. The NRC determined that *Identification* credit was not warranted because Violation A was identified through a self-revealing event.

Your corrective actions included: (1) a revised corrective action program that encompasses all dry cask storage operations at SONGS with a defined threshold for problem identification and entry; (2) additional staff training and resources to implement Southern California Edison Company's (SCE's) revised and more intrusive contractor oversight of dry cask storage operations; (3) additional equipment to provide load indications and visual indications for defense-in-depth to prevent a future disabling of important-to-safety downloader slings during spent fuel canister downloading operations; (4) a revised SONGS-specific training program for all dry cask storage workers to ensure that workers understand and know how to perform their assigned roles and responsibilities; (5) revised procedures that provide qualitative and quantitative means to ensure that important steps for dry cask storage operations have been accomplished; and (6) a commitment to enhance future management and executive management oversight through the above programs, policies, and procedures.

During the NRC's follow-up inspections, several weaknesses were identified by the inspection team related to the above-noted corrective actions. The three most significant weaknesses included failures to: (1) establish measures to ensure appropriate quality standards were specified in design documents for the new load monitoring equipment used in the downloading process; (2) ensure that newly-installed load monitoring equipment conformed to the procurement documents; and (3) conduct spent fuel handling operations within established design basis seismic criteria when moving loaded transfer casks from the site's spent fuel buildings to the independent spent fuel storage installation.

In addition, SCE's corrective actions did not adequately address a change to the design and performance requirements for certain structures, systems, and components described in the Holtec UMAX Final Safety Analysis Report (FSAR). At the time of the August 3, 2018, incident, the version of the Holtec UMAX FSAR in effect (i.e., Revision 4) stated that "there is no risk of scratching or gouging" on a canister during downloading operations into the UMAX vault. Following the special inspection, the FSAR was revised to allow scratches on the canisters during downloading operations. Southern California Edison Company used the Title 10 of the *Code of Federal Regulations* (10 CFR) 72.48 process to implement the FSAR change. The NRC determined that SCE's calculations and evaluation did not contain an adequate basis to support the change to the FSAR. As a result, SCE initiated corrective actions to reperform the 10 CFR 72.48 evaluation. The NRC will review SCE's subsequent evaluation to determine if the FSAR design change to allow scratches is acceptable.

Based on the overall assessment of SCE's corrective actions, the NRC has concluded that *Corrective Action* credit is not warranted for Violation A.

Since neither *Identification* credit nor *Corrective Action* credit are warranted for Violation A, the NRC Enforcement Policy provides for a civil penalty that is twice the base civil penalty amount of $58,000 for a total of $116,000.

Because Violation B was associated with a Severity Level III violation and your facility has not been the subject of an escalated enforcement action within the last 2 years, the NRC considered whether credit was warranted for *Corrective Action* in accordance with the civil penalty assessment process in Section 2.3.4 of the NRC Enforcement Policy. Your corrective actions included: (1) making the required notification to the NRC; (2) providing training to shift managers on the NRC reporting requirements; (3) revising your reporting procedures; and (4) establishing biennial refresher training on reportability. We have determined that these actions are sufficiently comprehensive and appropriate. Therefore, the NRC determined that *Corrective Action* credit was warranted, which would not result in a civil penalty for this Severity Level III violation.

Given the above, to emphasize the importance of identification and comprehensive correction of violations, I have been authorized, after consultation with the Director, Office of Enforcement, to issue the enclosed Notice of Violation and Proposed Imposition of Civil Penalty (Notice) in the amount of $116,000 for the Severity Level II violation (Violation A). In addition, issuance of this Notice constitutes escalated enforcement action that may subject you to increased inspection effort.

If you disagree with this enforcement sanction, you may deny the violation, as described in the Notice, or you may request ADR with the NRC in an attempt to resolve this issue. Alternative dispute resolution is a general term encompassing various techniques for resolving conflicts using a neutral third party. The technique that the NRC employs is mediation. Mediation is a voluntary informal process in which a trained neutral mediator works with parties to help them reach resolution. If the parties agree to use ADR, they select a mutually agreeable neutral mediator who has no stake in the outcome and no power to make decisions. Mediation gives parties an opportunity to discuss issues, clear up misunderstandings, be creative, find areas of agreement, and reach a final resolution of the issues. Additional information concerning the NRC's ADR program can be found in Enclosure 3 and at http://www.nrc.gov/about-nrc/regulatory/enforcement/adr.html.

The Institute on Conflict Resolution at Cornell University facilitates the NRC's program as a neutral third party. If you are interested in pursuing this issue through the ADR program, please contact: (1) the Institute on Conflict Resolution at 877-733-9415, and (2) Dr. Janine F. Katanic at 817-200-1151 within 10 days of the date of this letter. You may also contact the Institute on Conflict Resolution for additional information about ADR. Your submitted signed agreement to mediate using the NRC's ADR program will stay the 30-day time period for payment of the civil penalties and the required written response, as identified in the enclosed Notice, until the ADR process is completed.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In particular, you should address actions you have taken or plan to take to improve your corrective actions. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice and Procedure," a copy of this letter, its enclosures, and your response will be made available electronically for public inspection in the NRC Public Document Room and from the NRC's ADAMS, accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy or proprietary information so that it can be made available to the public without redaction. The NRC also includes significant enforcement actions on its Web site at http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions.

If you have any questions concerning this matter, please contact Dr. Janine F. Katanic of my staff at 817-200-1151.

Sincerely,

Scott A. Morris
Regional Administrator

Docket Nos. 50-206; 50-361; 50-362; 72-041
License Nos. DPR-13; NPF-10; NPF-15

Enclosures:
1. Notice of Violation and Proposed Imposition of Civil Penalty
2. NUREG/BR-0254, Payment Methods
3. NUREG/BR-0317, Enforcement Alternate Dispute Resolution Program

NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTY

Southern California Edison Company
San Clemente, California

Docket Nos. 050-00206, 050-00361,
050-00362, 072-00041
License Nos. DPR-13; NPF-10; NPF-15
EA-18-155

During an NRC inspection conducted September 10-14, 2018, two violations of NRC requirements were identified that were considered for escalated enforcement. (Note: three other Severity Level IV violations were identified and documented in the NRC special inspection report.) In accordance with the NRC Enforcement Policy, the NRC proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (Act), 42 U.S.C. 2282, and 10 CFR 2.205. The particular violations and associated civil penalty are set forth below:

I. Violation Assessed a Civil Penalty

A. 10 CFR 72.212(b)(3) requires, in part, that each cask used by the general licensee conforms to the terms, conditions, and specifications of a Certificate of Compliance listed in 10 CFR 72.214. 10 CFR 72.214 includes a list of all the approved spent fuel storage casks that can be utilized under the conditions specified in a specific Certificate of Compliance, including Amendment 2 of Certificate of Compliance 072-01040. Certificate of Compliance 072-01040, Amendment 2, Condition 4, "HEAVY LOADS REQUIREMENTS," requires, in part, that lifting operations outside of structures governed by 10 CFR Part 50 must be in accordance with Technical Specifications, Appendix A, Section 5.2.

Technical Specifications, Appendix A, Section 5.2.c.3 requires, in part, that the transfer cask, when loaded with spent fuel, may be lifted and carried at any height during multi-purpose canister transfer operations provided the lifting equipment is designed with redundant drop protection features which prevent uncontrolled lowering of the load.

Contrary to the above, on August 3, 2018, the licensee failed to ensure that the redundant drop protection features were available to prevent uncontrolled lowering of the load during multi-purpose canister transfer operations. Specifically, the licensee inadvertently disabled the redundant important-to-safety downloading slings while lowering canister 29 into the storage vault. During the approximately 45-minute time-frame, the canister rested on a shield ring unsupported by the redundant downloading slings at approximately 18 feet above the fully seated position. This failure to maintain redundant drop protection placed canister 29 in an unanalyzed condition because the postulated drop of a loaded spent fuel canister is not analyzed in the final safety analysis report.

This is a Severity Level II violation (NRC Enforcement Policy Section 6.3.b.2).
Civil Penalty - $116,000 (EA-18-155)

Enclosure 1

II. Violation Not Assessed a Civil Penalty

B. 10 CFR 72.75(d)(1) requires, in part, that each licensee shall notify the NRC within 24 hours after the discovery of an event involving spent fuel in which important-to-safety equipment is disabled or fails to function as designed when: (i) the equipment is required by Certificate of Compliance to be available and operable to mitigate the consequences of an accident; and (ii) no redundant equipment was available and operable to perform the required safety function.

Contrary to the above, from August 6 to September 14, 2018, the licensee failed to notify the NRC within the required time period after the discovery of an event involving spent fuel in which important-to-safety equipment was disabled or failed to function as designed when: (i) the equipment was required by Certificate of Compliance to be available and operable to mitigate the consequences of an accident; and (ii) no redundant equipment was available and operable to perform the required safety function.

Specifically, the licensee failed to notify the NRC within the required time period after an event that occurred on August 3, 2018, in which the licensee inadvertently disabled the redundant important-to-safety downloading slings while lowering spent fuel canister 29 into the storage vault, which resulted in the canister resting on a shield ring unsupported by the redundant downloading slings at approximately 18 feet above the fully seated position for approximately 45 minutes. These slings are required by Certificate of Compliance 072-01040, Amendment 2, Condition 4, and Technical Specification 5.2.c.3 to be available and operable during canister transfer operations, and no redundant equipment was available and operable to perform the required safety function.

This is a Severity Level III violation (NRC Enforcement Policy Section 6.9.c.2).

Pursuant to the provisions of 10 CFR 2.201, Southern California Edison Company (SCE) is hereby required to submit a written statement or explanation to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, with a copy to the Document Control Desk, Washington, DC 20555-0001, and the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV within 30 days of the date of this Notice of Violation and Proposed Imposition of Civil Penalty (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-18-155" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken; and (4) the date when full compliance will be achieved.

Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, the NRC may issue an order or a Demand for Information requiring you to explain why your license should not be modified, suspended, or revoked or why the NRC should not take other action as may be proper. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

You may pay the civil penalty proposed above, in accordance with NUREG/BR-0254 (Enclosure 2) and by submitting to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, a statement indicating when and by what method payment was made, or may

protest imposition of the civil penalty in whole or in part, by a written answer addressed to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, within 30 days of the date of this Notice.

Should SCE fail to answer within 30 days of the date of this Notice, the NRC will issue an order imposing the civil penalty. Should SCE elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalty, in whole or in part, such answer should be clearly marked as an "Answer to a Notice of Violation; EA-18-155" and may: (1) deny the violations listed in this Notice, in whole or in part; (2) demonstrate extenuating circumstances; (3) show error in this Notice; or (4) show other reasons why the penalty should not be imposed. In addition to protesting the civil penalty in whole or in part, such answer may request remission or mitigation of the penalty.

In requesting mitigation of the proposed penalty, the response should address the factors in Section 2.3.4 of the Enforcement Policy. Any written answer addressing these factors pursuant to 10 CFR 2.205, should be set forth separately from the statement or explanation provided pursuant to 10 CFR 2.201, but may incorporate parts of the 10 CFR 2.201 reply by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. Your attention is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing a civil penalty.

Upon failure to pay any civil penalty which subsequently has been determined in accordance with the applicable provisions of 10 CFR 2.205 to be due, this matter may be referred to the Attorney General, and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282c.

The responses noted above, i.e., Reply to Notice of Violation, Statement as to payment of civil penalty, and Answer to a Notice of Violation, should be addressed to: Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, with a copy to the Document Control Desk, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001 and the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 1600 E. Lamar Blvd., Arlington, TX 76011-4511. Your response will be made available electronically for public inspection in the NRC Public Document Room or in the NRC's Agencywide Documents Access and Management System (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, it should not include any personal privacy or proprietary information so that it can be made available to the public without redaction.

If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request that such material is withheld from public disclosure, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information).

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days of receipt.

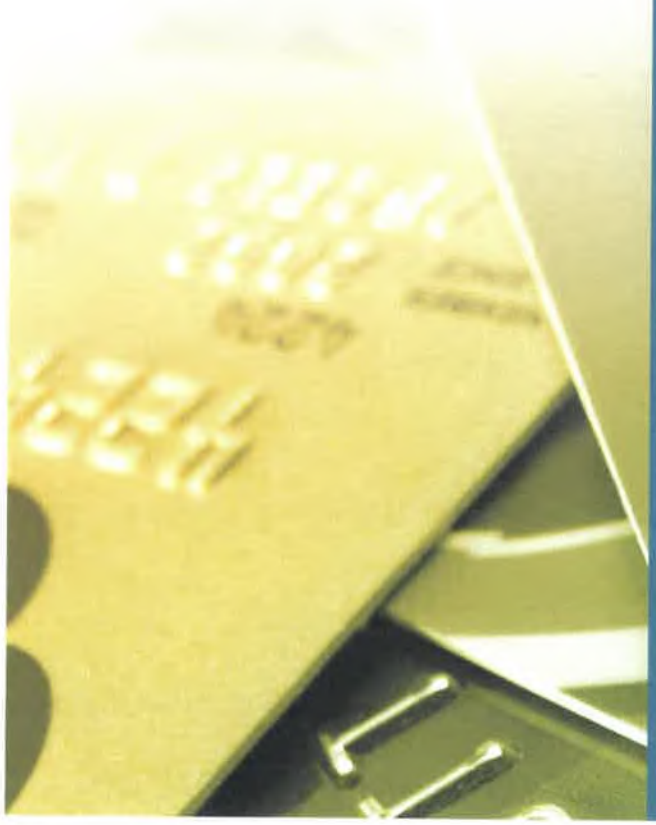
Dated this 25th day of March 2019.

QUESTIONS?

If you have questions, please visit https://www.nrc.gov and search for "License Fees."

Questions may also be directed to the NRC Accounts Receivable Help Desk by e-mail at FEES.Resource@nrc.gov, by phone at (301) 415-7554, or by writing to the address below:

U.S. NUCLEAR REGULATORY COMMISSION
OCFO/DOC/ARB
Mail Stop T9-E10
Washington, DC 20555-0001



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Washington, DC 20555-0001
PH (301) 415-7554

NUREG/BR-0254, Rev. 8
February 2018

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U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Payment Methods

ENCLOSURE 2

APPROVED BY OMB: NO. 3150–0190

Estimated burden per response to comply with this voluntary collection request: 10 minutes. This brochure provides information about available payment methods. Forward comments about to burden estimate to the Records Management Branch (T6-F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0190), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

NRC accepts the methods described below.

PAYMENT BY AUTOMATED CLEARINGHOUSE

To pay by Automated Clearinghouse / Electronic Data Interchange (ACH/EDI), provide a copy of NRC Form 628 to your financial institution. You may obtain a copy of NRC Form 628 by calling the NRC Accounts Receivable Help Desk at (301) 415-7554.

PAYMENT BY CREDIT CARD

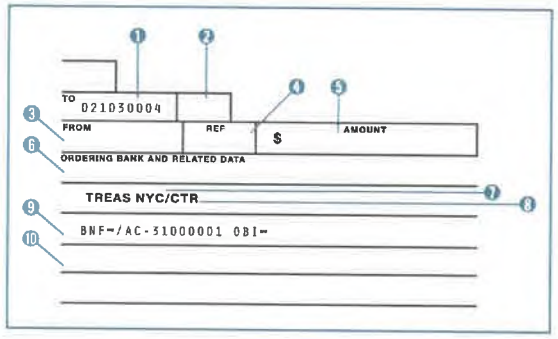
The NRC is currently accepts credit card payments of up to $24,999.99. For payment by credit card, go to Pay.gov, search for "U.S. Nuclear Regulatory Commission Fees" and enter the required information.

You may also mail or fax NRC Form 629 following the directions on the form. To obtain a copy of NRC Form 629 go to http://www.nrc.gov and search for "NRC Form 629" or call the NRC Accounts Receivable Help Desk at (301) 415-7554.

PAYMENT BY FEDWIRE DEPOSIT SYSTEM

The NRC can receive funds through the U.S. Department of the Treasury (Treasury) Fedwire Deposit System. The basic wire message format below complies with the Federal Reserve Board's standard structured third-party format for all electronic funds transfer (EFT) messages.

See the sample EFT message to Treasury below. Each numbered field is described below.



❶ **RECEIVER-DFI#** – Treasury's routing number for deposit messages is 021030004.

❷ **TYPE-SUBTYPE-CD** – The sending bank will provide the type and subtype code.

❸ **SENDER-DFI#** – The sending bank will provide this number.

❹ **SENDER-REF#** – The sending bank will insert this 16-character reference number at its discretion.

❺ **AMOUNT** – The transfer amount must be punctuated with commas and decimal point; use of the "$" is optional. The depositor will provide this item.

❻ **SENDER-DFI-NAME** – The Federal Reserve Bank will automatically insert this information.

❼ **RECEIVER-DFI-NAME** – Treasury's name for deposit messages is "TREAS NYC". The sending bank will enter this name.

❽ **PRODUCT CODE** – A product code of "CTR" for customer transfer should be the first item in the reciever text field. Other values may be entered, if appropriate, using the American Bankers Association's options. A slash must be entered after the product code.

❾ **AGENCY LOCATION CODE (ALC)** – THIS ITEM IS OF CRITICAL IMPORTANCE. IT MUST APPEAR ON THE FUNDS TRANSFER DEPOSIT MESSAGE IN THE PRECISE MANNER AS STATED TO ALLOW FOR THE AUTOMATED PROCESSING AND CLASSIFICATION OF THE FUNDS TRANSFER MESSAGE TO THE AGENCY LOCATION CODE OF THE APPROPRIATE AGENCY. The ALC identification sequence can, if necessary, begin on one line and end on the next line; however, the field tag "BNF=" must be on one line and cannot contain any spaces. The NRC's 8-digit ALC is: BNF=/AC-31000001

❿ **THIRD-PARTY INFORMATION** – The Originator to Beneficiary Information (OBI) field tag "OBI=" signifies the beginning of the free-form third-party text. All other identifying information intended to enable the NRC to identify the deposit—for example, NRC annual fee invoice number, description of fee, 10 CFR 171 annual fee, and licensee name—should be placed in this field.

The optimum format for fields 7, 8, 9, and 10 using an 8-digit ALC is as follows:

TREAS NYC/CTR/BNF=/AC-31000001 OBI=

The optimum format, shown above, will allow 219 character positions of information following the "OBI=" indicator.

If the licensee's bank is not a member of the Federal Reserve System, the nonmember bank must transfer the necessary information and funds to a member bank, which then must transfer the information and funds to the local Federal Reserve Bank.

For a transfer of funds from local Federal Reserve Banks to be recorded on the same day, the transfer must be received at the New York Federal Reserve Bank by 4 p.m., EST. Otherwise, the deposit will be recorded on the next workday.

PAYMENT BY CHECK

Checks should be made payable to the U.S. Nuclear Regulatory Commission with the invoice number, Enforcement Action number, or other information that identifies the payment, written on the check. Mail the check to the following address:

U.S. Nuclear Regulatory Commission
U.S. Bank
P.O. Box 979051
St. Louis, MO 63197-9000

FedEx or overnight mailings must be delivered to the following address:

U.S. Nuclear Regulatory Commission
U.S. Bank Government Lockbox
SL-MO-C2GL
1005 Convention Plaza
St. Louis, MO 63101

TAXPAYER IDENTIFICATION NUMBER

You must file your Taxpayer Identification Number (TIN) with the NRC. Use NRC Form 531 to provide your TIN. You may obtain NRC Form 531 from the NRC Web site at http://www.nrc.gov by searching for "NRC Form 531" or by calling the NRC Accounts Receivable Help Desk at (301) 415-7554.

Mediation Location and Duration

The parties usually hold the mediation at or near one of the NRC's offices. However, the parties may agree on any alternate location. Mediation sessions are usually no longer than 1 day. In some cases, the mediation may take longer with the mutual consent of the parties.

The NRC Mediation Team

The responsible NRC senior manager (i.e., Office Director, Regional Administrator, or his or her designee) will serve as the principal negotiator for the NRC in cases that involve wrongdoing and technical issues. When a case involves discrimination, the Director of the Office of Enforcement will serve as the principal negotiator. The other members of the NRC mediation team typically include an enforcement specialist, an attorney, and a staff representative who is familiar with any technical issues under discussion.

The Confirmatory Order

A CO is a legally binding document that includes the terms of the AIP. The NRC will issue a CO only with the prior written consent of the other party and with a waiver of the right to a hearing. After the entity or the individual has completed the terms of the CO, the NRC will verify that the terms of the CO have been satisfied in a timely manner. Because the CO is legally binding, failing to comply with its terms exposes the entity or individual to additional enforcement action.

Although the substance of the mediation session remains confidential, the details of the settlement will normally be made public via a press release and the publication of the CO in the *Federal Register*.

Timeliness Goals

The timely resolution of issues is one of the goals of the enforcement ADR program. Accordingly, the NRC expects timely progress of a case at each stage of the mediation process. In cases where the parties achieve settlement, the NRC expects to issue a CO within 90 calendar days of the date of the agency's letter offering the ADR option to the other party.

Additional Sources of Information

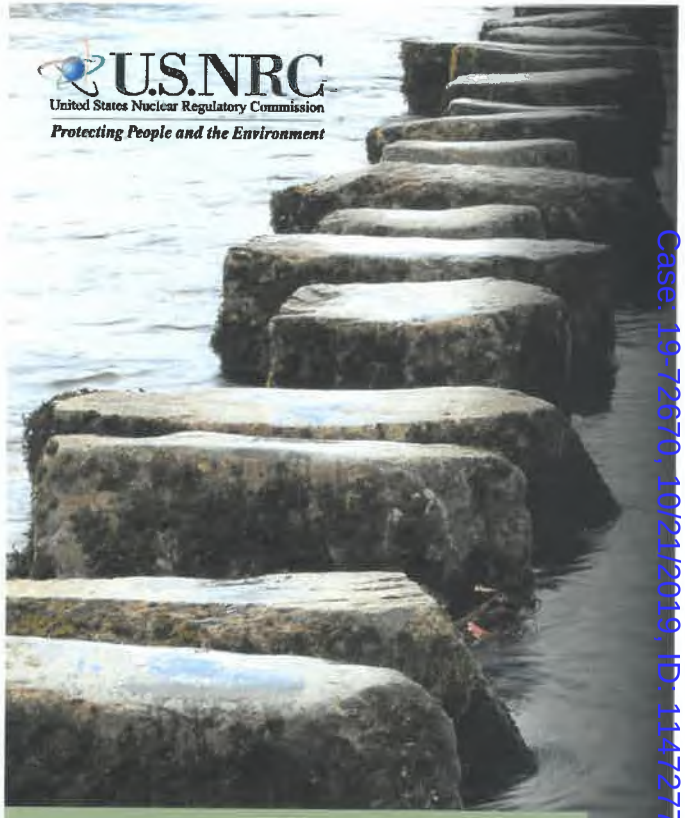
More information about the NRC's ADR program is available from the following:

- Cornell University's Scheinman Institute on Conflict Resolution
  Toll-Free Number: (877) 733-9415

- The NRC's ADR Program Manager in the Office of Enforcement
  Toll-Free Number: (800) 368-5642 or (301) 287-9527

- The NRC enforcement ADR program on the agency's Web site at www.nrc.gov/about-nrc/regulatory/enforcement/adr.html

NUREG/BR-0317 Rev. 2
May 2018



U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Enforcement Alternative Dispute Resolution Program

ENCLOSURE 3

Case: 19-72670, 10/21/2019, ID: 11472770, DktEntry: 1-3, Page 636 of 1606
(638 of 1608)

The Program

The U.S. Nuclear Regulatory Commission's (NRC's) enforcement alternative dispute resolution (ADR) program, formerly referred to as "post-investigation ADR," provides an amicable process for resolving enforcement matters. It is intended to produce more timely and effective outcomes for the NRC and an entity (e.g., an NRC licensee, certificate holder, or contractor of an NRC licensee or certificate holder) or an individual who is subject to an enforcement action, through mediation.

The NRC established the post-investigation ADR program in 2004. In 2015, the NRC expanded its scope to include certain types of enforcement cases that do not involve an investigation. Accordingly, the name of this program was changed from "post-investigation ADR" to "enforcement ADR."

Enforcement ADR includes two distinct case types: (1) discrimination cases or other wrongdoing and, (2) nonwillful (traditional) enforcement cases with the potential for civil penalties (not including violations associated with findings assessed through the Reactor Oversight Process). For discrimination cases or other wrongdoing, mediation is used after the completion of an investigation by the NRC Office of Investigations.

As long as the enforcement matter is within the scope of the program, the NRC normally offers enforcement ADR at each of the following stages of the enforcement process: (1) before an initial enforcement action, (2) after the initial enforcement action is taken, typically upon issuance of a notice of violation, and (3) when a civil penalty is imposed but before a hearing request.

Mediation is an informal process in which a trained and experienced mediator works with the parties to help them reach a resolution. The parties are the NRC and the entity or individual in the mediation. The mediator focuses the attention of the parties on their needs and interests rather than on their stated positions. Mediation gives the parties an opportunity to discuss issues, clear up misunderstandings, identify creative ways to address issues, find areas of agreement, and resolve their dispute.

Participation in the program is entirely voluntary. The NRC and the entity or the individual may withdraw from the mediation process at any time.

The Program Administrator

The NRC has a contract with the Cornell University Scheinman Institute on Conflict Resolution (Cornell) to serve as the program administrator for the enforcement ADR program. Cornell manages the logistics associated with enforcement ADR, including working with the parties to select a mediator from Cornell's roster of mediators. Cornell uses a network of independent and experienced mediators who help the parties find areas of agreement and settle their dispute.

The Mediator

The mediator is an experienced neutral individual who is mutually selected by the parties. He or she has no stake in the outcome of the mediation or any power to make decisions that may bind either party. The role of the mediator is to facilitate communication between the parties and to provide an environment where the parties can address their differences. The mediator uses consensus-building skills and knowledge of negotiation to help the parties find ways to overcome any misunderstandings and find areas of agreement. The mediator does not act as legal counsel or provide legal advice. Each party should consult an attorney for legal advice as appropriate.

The Mediation Process

Historically, most enforcement ADR mediations have occurred at the first stage of the enforcement process (i.e., before an initial enforcement action). In those cases, the NRC presents the entity or the individual with the opportunity to engage in mediation with the agency before it makes an enforcement decision. If the entity or the individual elects ADR, Cornell will help the NRC and the entity or the individual, jointly select a mediator. After selecting a mediator, the parties, in coordination with the mediator, set a date and place for the mediation. Typically, the mediator holds a premediation teleconference with the parties to discuss logistics or any special needs.

During the mediation, the mediator will give the parties an opportunity to discuss their views on the issue. Often, the mediator will meet privately with each party to develop a clear understanding of the party's perspective and explore and assess options. Although the mediator does not have any power to make decisions that may bind either party, he or she may ask questions intended to help the parties assess the merits of their positions, help them converse in a respectful atmosphere, and identify potential settlement options.

If the parties reach a settlement agreement during the mediation session, they will typically document the terms of their agreement in writing by developing an agreement in principle (AIP) document. The AIP is not enforceable by either party against the other, but it is the basis on which the NRC drafts a confirmatory order (CO). The CO is a legally binding document used to confirm the commitments made in the AIP. However, if the parties do not reach a settlement agreement, the traditional enforcement process resumes—that is, the enforcement process continues as it would have if the parties had not engaged in ADR.

Confidentiality

Although the terms of an ADR settlement become publicly available through the issuance of the CO, with certain exceptions, the substance of the discussions during the mediation session is confidential. The mediator is prohibited from discussing the mediation proceedings, testifying on anyone's behalf concerning the mediation, or submitting a report on the substance of the discussions.

Cost

The NRC and the entity or individual, equally share the fees and travel expenses of the mediator and any meeting room fees. However, each party is responsible for its own expenses, such as travel, lodging, and legal representation.

NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $116,000 AND NRC SPECIAL INSPECTION REPORT 050-00206/2018-005, 050-00361/2018-005, 050-00362/2018-005, 072-00041/2018-001 DATED - MARCH 25, 2019

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MBurgess, NMSS
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ADAMS ACCESSION NUMBER: ML19080A208

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DATE	02/22/19	02/27/19	02/26/19	02/27/19	03/04/19	02/28/19
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NAME	TPruett	GWilson	CRegan	MSimon	SMorris	
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DATE	03/5/19	03/14/19	03/12/19	03/13/19	03/21/19	

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EXHIBIT 18

1 SAN ONOFRE DECOMMISSIONING
2 COMMUNITY ENGAGEMENT PANEL MEETING
3 STATE OF CALIFORNIA, COUNTY OF ORANGE
4
5
6
7
8
9
10
11
12 TRANSCRIPT OF VIDEOTAPED PROCEEDINGS
13 LAGUNA HILLS, CALIFORNIA
14 THURSDAY, MARCH 22ND, 2018
15
16
17
18
19
20
21
22 Reported by:
Katherine Magner
23 CSR No. 14083
Job No. 2846039
24
25

1 COMMUNITY ENGAGEMENT PANEL MEMBERS:
2 DR. DAVID G. VICTOR
CEP CHAIRMAN
3
JERRY KERN
4 CEP SECRETARY
5 DAN STETSON
VICE CHAIRMAN
6
BILL HORN
7 SAN DIEGO COUNTY SUPERVISOR
(Not Present)
8
9 TOM CAUGHLAN
CAMP PENDLETON
10
MARNI MAGDA
11 SIERRA CLUB, ANGELES CHAPTER
12 TED QUINN
AMERICAN NUCLEAR SOCIETY
13
STEVE SWARTZ
14 CITY OF SAN CLEMENTE
15 GARRY BROWN
ORANGE COUNTY COASTKEEPER
16
MARTHA MCNICHOLAS
17 CAPISTRANO UNIFIED SCHOOL DISTRICT
18 CAPTAIN MEL VERNON
SAN LUIS REY BAND OF MISSION INDIANS
19
SERGIO FARIAS
20 MAYOR, SAN JUAN CAPISTRANO
21 DONNA BOSTON
ORANGE COUNTY SHERIFF'S DEPARTMENT
22
TOM PALMISANO
23 VICE PRESIDENT, DECOMMISSION
CHIEF NUCLEAR OFFICER AT SONGS
24
RICH HAYDEN
25 CALIFORNIA STATE PARKS

1 them you need to tell me how you're going to remediate
2 this, and they came back and said we want to go back to
3 the older design.
4 CHAIRMAN DR. VICTOR: People are going to want
5 to know about these four canisters. Why not take eight 19:05:32
6 or ten days and move them back into the pool, and unload
7 them and reload them? Help us understand. I know, it's
8 early days.
9 MR. PALMISANO: Sure.
10 CHAIRMAN DR. VICTOR: Help us understand what 19:05:45
11 the logic process is going to be there.
12 MR. PALMISANO: Yeah. And let me just --
13 because I faced this issue back in the mid '90s at the
14 Palisades Nuclear Plant with a loaded canister that had a
15 potential weld defect and got into this very discussion. 19:05:58
16 So nobody has unloaded a commercial canister,
17 either a bolted cask or a welded cask or canister. Okay.
18 It is possible. What you would do is basically have a
19 mechanism, either to do it in a fuel pool or do it in a
20 dry transfer facility. It's possible either way. 19:06:15
21 You would take the canister back in. And the
22 first thing you would do is reconnect the valves and find
23 a way to purge the helium and refill its hole with water.
24 Okay.
25 The biggest technical issue that we've looked at 19:06:29

1 in the industry over the many years -- not just related
2 to SONGS -- is the thermal transient to actually
3 reintroduce water into a -- let's say a canister with hot
4 fuel, 200-300 degrees C. And the thermal transient that
5 you put the fuel through. Okay. 19:06:44
6 So once you get it reflooded, cooled down, you
7 would then put that similar machine on, grind out the
8 weld, take the lid off. That's just the mechanics.
9 That's certainly doable.
10 The real challenge as we would understand it 19:06:54
11 today, and nobody has had to do it yet, is the reflood.
12 Certainly, technically possible. What I would tell you
13 is just I was back in Washington with the NRC last week,
14 if you were just to brainstorm, this would probably be a
15 two- to three-year project to develop the techniques, 19:07:09
16 pile up the techniques. The NRC would want to have
17 explicit approval on this because of the radiological
18 hazards.
19 CHAIRMAN DR. VICTOR: To the workers?
20 MR. PALMISANO: Well, to the workers, yeah. 19:07:20
21 So when you think about this, you have a
22 canister that has intact fuel rods inside of a sealed
23 canister. This pin problem doesn't affect the canister
24 itself. Okay. So you've got that condition.
25 You've got to weigh that condition -- if this 19:07:34

EXHIBIT 19

Application No.: 18-03-XXX
Exhibit No.: SCE-03
Witnesses: Jose L. Perez
Nicholas Capik

SOUTHERN CALIFORNIA EDISON®

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(U 338-E)

Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California
March 15, 2018

SCE-03: Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3

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SCE-03: Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3

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SCE-03: Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3

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I.

INTRODUCTION

The purpose of this testimony is to demonstrate the reasonableness of the 2017 Decommissioning Cost Estimate for San Onofre Nuclear Generating Station Unit Nos. 2&3 (2017 SONGS 2&3 DCE). The 2017 DCE estimates that the total cost to decommission SONGS 2&3 will be $4,479 million (100% share, 2014 $), an increase of approximately 1.5% over the 2014 SONGS 2&3 DCE. The Commission-approved 2014 DCE estimated that the total cost to decommission SONGS 2&3 would be $4,411 million (100% share, 2014 dollars).

Chapter II of this testimony provides a summary of the 2017 DCE. Chapter III provides testimony from ABZ Incorporated (ABZ), a third-party consultant who performed an independent review of the 2017 DCE. Chapter IV provides a detailed reconciliation of the 2017 DCE to the 2014 DCE. Chapter V concludes SCE's testimony.

II.

SUMMARY OF 2017 SONGS 2&3 DECOMMISSIONING COST ESTIMATE

A. Methodology and Description

SCE and the other SONGS participants[1] began accumulating funds for the eventual decommissioning of SONGS 2&3 early in the units' operating lives. Because the units were licensed to operate for several decades,[2] decommissioning fund accumulations were based on conceptual cost estimates.[3] These conceptual DCEs were developed by third-party vendors using proprietary estimating algorithms consistent with recognized industry guidelines such as AIF/NESP-036, "Guideline for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" and the Department of Energy (DOE) Decommissioning Handbook.[4] These estimates were updated periodically to reflect changes in regulations, technology, and economics; additions and deletions to the nuclear facilities;

---

[1] San Diego Gas & Electric Company and the City of Riverside own 20% and 1.79% shares of SONGS 2&3, respectively. On December 29, 2006, SCE acquired the City of Anaheim's ownership share of SONGS 2&3. Under the Anaheim Settlement Agreement adopted by the Commission in D.06-11-025, however, the City of Anaheim retained a pro-rata share of the SONGS 2&3 decommissioning obligation as shown approximately in the table below:

Decommissioning Obligation		
	SONGS 2	SONGS 3
SCE	75.7363%	75.7475%
SDG&E	20.0000%	20.0000%
Anaheim	2.4737%	2.4625%
Riverside	1.7900%	1.7900%
	100.00%	100.00%

[2] On March 9, 2000, the U.S. Nuclear Regulatory Commission issued Amendment No. 166 to Facility Operating License No. NPF-10 and Amendment No. 157 to Facility Operating License No. NPF-15 for San Onofre Nuclear Generating Station (SONGS) Units 2 and 3, respectively. These amendments revised the expiration dates of the SONGS 2 and SONGS 3 operating licenses from October 18, 2013, to February 16, 2022 and November 15, 2022, respectively.

[3] In this context, "conceptual" means that the decommissioning cost estimates were developed based on Unit Cost Factors coupled with the Critical Path Method, using the best-available current information, for projects that were not expected to commence until several years or decades into the future. These "conceptual" cost estimates were not intended to be executable decommissioning project plans or schedules.

[4] *See* Decommissioning Cost Estimate for SONGS 2&3 Prepared for SCE by ABZ Incorporated, dated December 14, 2012, page 5. From 2001 to 2013, SCE utilized ABZ, Incorporated to develop the decommissioning cost estimates for SONGS 2&3. Prior to 2001, SCE utilized TLG Services, Incorporated to develop the decommissioning cost estimates for SONGS 1 and for SONGS 2&3.

updated site radiological assumptions; lessons-learned from other nuclear decommissioning projects; and other related information necessary to complete accurate cost estimates.

On July 22, 2013, after SCE announced its decision to permanently retire SONGS 2&3, SCE notified the Commission that it intended to prepare a new DCE for SONGS 2&3 after the development of a site-specific decommissioning plan.[5] SCE informed the Commission that this new estimate would be included in the Post Shutdown Decommissioning Activities Report (PSDAR) that SCE was required to submit to the NRC.[6]

SCE retained the consortium of Energy*Solutions* and Chicago Bridge & Iron Company (ES/CBI) to develop the 2014 SONGS 2&3 DCE, which included the total estimated cost for the decommissioning project. SCE and SDG&E submitted the 2014 DCE to the Commission in Application (A.) 14-12-007. The Commission adopted the 2014 SONGS 2&3 DCE in Decision (D.) 16-04-019.

As required by the California Nuclear Facilities Decommissioning Act of 1985[7] (Decommissioning Act), SCE is required to periodically update the SONGS 2&3 DCE. Therefore, in 2017, SCE engaged The Kenrich Group (Kenrich)[8] to prepare the 2017 SONGS 2&3 DCE. This DCE is consistent with the guidance provided in NRC Regulatory Guide 1.202, "Standard Format and content of Decommissioning Cost Estimates for Nuclear Power Reactors." The 2017 DCE presents the total estimated project cost, including recorded costs to date, to allow for comparisons to the 2014 DCE. That is, the 2017 DCE includes recorded costs from project inception through September 30, 2017, and estimated costs from October 1, 2017 through assumed project completion in 2051. The 2017 DCE estimates that the total cost to decommission SONGS 2&3 will be $4,479 million (100% share, 2014 $). The 2017 DCE uses the same Work Breakdown Structure (WBS) that was used in the 2014 DCE, and includes the following new and updated information:

- The pricing for the contract awarded to Holtec International, Inc., (Holtec) for the Independent Spent Fuel Storage Installation (ISFSI) expansion and the transfer of spent fuel from the SONGS 2&3 spent fuel pools to the ISFSI;

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[5] A.12-12-013, Exhibit SCE-06, page 1.

[6] *Id.*

[7] Pub. Utilities Code § 8321 et. seq.

[8] *See* Exhibit SCE-01, pages 17-18.

- The pricing for the contract awarded to SONGS Decommissioning*Solutions* (SDS) for the decontamination and dismantlement (D&D) of SONGS 2&3, and the removal and disposal of radiological, hazardous, and non-hazardous waste;

- Recorded costs through September 30, 2017;

- Revised DOE spent fuel acceptance date to reflect DOE's continued failure to perform its contractual obligations to pick up fuel from commercial nuclear reactors during the four years since the 2014 DCE was completed;

- Revised environmental review costs and approval dates based on the current permitting strategy and the requirements of the California State Lands Commission (CSLC), the California Coastal Commission (CCC), and the U.S. Department of the Navy (Navy);

- Revised project execution strategy, including the deferral of the start of substructure removal until 2046;

- Updated undistributed cost projections based on historical recorded costs and revised projections;

- Updated ISFSI demolition costs to reflect the final design of the Holtec ISFSI; and

- Other project costs not previously identified.

Significant components of the 2017 DCE are now based on competitively bid contracts, as well as three additional years of experience managing a decommissioning plant and overseeing decommissioning personnel. Where new information was not available, Kenrich worked with third-party consultants and SCE personnel to validate and refine the cost and schedule assumptions for 2017 SONGS 2&3 DCE.

B. <u>2017 DCE Assumptions</u>

The 2017 DCE includes the following assumptions that have not changed from the 2014 SONGS 2&3 DCE:

- SONGS 2&3 will be decommissioned using the prompt DECON decommissioning methodology;

- All fuel assemblies will be transferred from the SONGS 2&3 spent fuel pools to the ISFSI by mid-2019;

- A dry transfer facility will not be necessary to transfer the spent fuel canisters to DOE transport canisters;
- Decommissioning will be performed by a decommissioning general contractor (DGC) with oversight by the SONGS Participants;
- SONGS 2&3 major D&D activities will be completed by the end of 2028;
- All onshore substructures and offshore conduits will be removed; and
- ISFSI decommissioning, NRC license termination, and site lease termination will be completed by the end of 2051.

In addition, the 2017 DCE is based on the following updated assumptions:

- SONGS 2&3 D&D will commence in January 2019 based on expected completion dates of environmental reviews and approvals; and
- The DOE will commence accepting spent fuel from U.S. commercial nuclear facilities in 2028, which results in the DOE removing the last spent fuel from the SONGS ISFSI in 2049.

C. Contingency

Contingency is applied to cost estimates to account for unknown or unplanned occurrences during the performance of a project. "Contingency" is defined in the American Association of Cost Engineers *Project and Cost Engineers' Handbook* as, "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating to estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The consensus in the industry literature, including sources from the DOE[9] and the Association for the Advancement of Cost Engineering International,[10] is that a contingency factor for cost estimates in this stage of development should fall within a range of 15% to 30%.

In its decision for the 2005 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), the Commission ordered the Utilities (SCE, SDG&E, and PG&E) to serve testimony in the next NDCTP

[9] Chapter 11 of U.S. Department of Energy (DOE) Decommissioning Implementation Guide DOE, G 430.1-1, March 28, 1997.

[10] Association for the Advancement of Cost Engineering International, Recommended Practice No. 18R-97, at page 2 of 9.

that demonstrates they have made all reasonable efforts to conservatively establish an appropriate contingency factor for inclusion in the decommissioning revenue requirements.[11]

To comply with this Commission order, in the 2009 NDCTP,[12] which occurred at a time when the Utilities still believed that decommissioning would not begin until decades in the future, PG&E prepared a paper titled, *Technical Position Paper for Establishing an Appropriate Contingency Factor for Inclusion in the Decommissioning Revenue Requirements*. Based on industry and regulatory documents, the position paper concluded that it is appropriate to add a 25% contingency factor to estimated decommissioning costs because it provides reasonable assurance for unforeseen circumstances[13] that could increase decommissioning costs, and should not be reduced or eliminated simply because foreseeable costs are low. In that proceeding, SCE agreed based on its own independent research that the 25% contingency factor was conservative and appropriate.[14] Consistent with this assumption, each of the DCEs submitted by the Utilities in that proceeding contained a 25% contingency factor. The Commission found that each such DCE was reasonable.[15]

Later, an Independent Review Panel (Panel) examined the definition and role of contingency factors in DCEs.[16] The Panel identified that DCEs should consider four types of risk or uncertainty, including: (1) performance risk; (2) scope risk; (3) regulatory risk; and (4) financial risk.[17] The Panel found that the DCEs prepared by third-party vendors on behalf of the Utilities typically only addressed performance risks by including 17%-22% contingency, and that the Utilities' adjustments to target their DCEs' overall contingency to 25% was intended to capture all risks, and was consistent with the

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[11] D.07-01-003, Ordering Paragraph 8.

[12] A.09-04-007 and A.09-04-009.

[13] For example, some activities in the remaining decommissioning work are less familiar activities in the industry. To terminate the easement with the Navy, SCE may be required to perform extensive site restoration work that is unique to the SONGS site.

[14] D.10-07-047, page 23.

[15] *Id*., Conclusions of Law 4, 5, 6, 7, 13, and 14. Also see D.11-07-003 at page 25.

[16] Report on Nuclear Decommissioning, February 28, 2011, For The California Public Utilities Commission, Prepared by Nicholas Capik, Geoffrey Griffiths, and Bruce Lacy, at pages 40-42.

[17] *Id*., at page 40. Financial risk is typically addressed through conservative assumptions for cost escalation and fund earnings rates.

contingency value normally used by the NRC.[18] The Commission also approved SCE's decommissioning cost estimates in the 2012 NDCTP and SCE's 2014 SONGS 2&3 DCE, each of which also included a 25% contingency factor.[19]

In the 2017 SONGS 2&3 DCE, SCE did not apply contingency to the $1,156 million (100% share, 2014 $) of SONGS 2&3 decommissioning costs that were recorded between June 2013 and September 2017. For work scopes that have been contracted or are well defined in the 2017 DCE, SCE applied lower contingency factors. Kenrich and knowledgeable SCE personnel reviewed each DCE line item, giving consideration to the technical complexity, contracting status, estimating approach, and timing of each work scope, and applied an appropriate contingency factor. For decommissioning activities in the 2017 DCE that will not be performed until decades in the future when their scopes become better defined, SCE applied a 25% contingency factor as approved by the Commission in the past several NDCTPs.

[18] *Id.*, see Footnote 37.

[19] See D.14-12-082 at page 38, Findings of Fact 13, and Conclusions of Law 17, 22, 23, and 24; and D.16-04-019 Conclusion of Law 1.

Table II-1 below identifies the range of contingency factors utilized for each 2017 DCE cost category:

Table II-1
Contingency Factors Applied in 2017 DCE

2017 DCE Category	Contingency Factor
Recorded Costs Through September 2017	0%
Service Level Agreements	10%
Undistributed Labor	10%
ISFSI & Fuel Transfer Operations	[redacted]
Undistributed Non-Labor	15%
[redacted]	[redacted]
ISFSI Aging Management	20%
Plant Easement/Lease Renewals	20%
Other Projects	15-20%
GTCC Waste Storage	25%
Offshore Conduit Removal	25%
Substructure Removal	25%
ISFSI Demolition	25%
Final Site Restoration	25%

The composite contingency factor included in the 2017 DCE is approximately [redacted] of the base costs.

III.

INDEPENDENT REVIEW OF 2017 SONGS 2&3 DCE

A. Introduction

This testimony describes ABZ, Incorporated's (ABZ) independent review of the 2017 San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 Decommissioning Cost Estimate (DCE), and the conclusions reached by ABZ in that review.

Nick Capik was the project manager and principal author of the ABZ review of the 2017 SONGS 2&3 DCE. In this testimony, he describes the scope of ABZ's review and the conclusions reached during that review.

B. ABZ Background And Experience

ABZ was founded in 1986 to provide consulting and engineering services to the nuclear power industry. ABZ supports nuclear decommissioning projects in a number of ways including cost estimating, licensing, project management, due diligence, and litigation. ABZ has been engaged from conceptual design of decommissioning through implementation and site restoration.

ABZ has also prepared or reviewed 43 decommissioning cost estimates covering 63 nuclear plants. This includes preparing DCEs for SONGS 2 & 3 from 2001 through 2014. These SONGS cost estimates were accepted by the California Public Utilities Commission (CPUC) as reasonable and formed the basis for ratemaking for decommissioning collections. In addition, I participated as the ABZ representative in an Independent Review Panel established by the CPUC to examine decommissioning cost issues as part of Decision (D.) 10-07-047. As part of this work, ABZ evaluated the 2008 SONGS 2&3 DCE in comparison to Pacific Gas and Electric's Diablo Canyon estimate, the Palo Verde Nuclear Generating Station estimate, and the estimates for four other similar nuclear power plant sites. Significant areas of focus included cost and financial assumptions, waste management approaches, state requirements for site restoration, severance costs, and use of actual industry performance and cost data.

In addition to cost estimating, ABZ has performed direct oversight of decommissioning activities for several nuclear power plant decommissioning projects, including Zion, Trojan, and Shoreham. ABZ

staff has provided additional support for decommissioning at Connecticut Yankee, Maine Yankee, Yankee Rowe, Fort St. Vrain, Millstone, and others.

ABZ has participated in litigation associated with decommissioning in several venues, including the U.S. Court of Claims, U.S. Tax Court, and State proceedings. Finally, ABZ has performed due diligence reviews of decommissioning plans, efforts, and costs as part of two nuclear plant sales.

C. ABZ Independent Review

1. Scope

ABZ performed an independent review of the 2017 SONGS 2&3 DCE. This review was conducted in several phases as the DCE was being developed such that responses to ABZ comments and questions could be evaluated and incorporated into the final DCE. ABZ's review focused on key assumptions, scope and cost of decommissioning projects, project schedules, and undistributed costs, including staffing, and contingency.

2. Review Process

ABZ reviewed the draft DCE and supporting information over a seven-month period in 2017. ABZ performed distinct reviews at 60 percent complete, 90 percent complete, and just prior to issuance of the final DCE. ABZ's intent was to assess the reasonableness of the DCE assumptions, project scopes, costs, and schedule. ABZ provided comments addressing the scope of the estimate compared to previous SONGS estimates and industry experience, estimated costs, work completed to date, and assumptions used in preparing the estimate.

ABZ started by reviewing the key assumptions of the DCE for reasonableness. ABZ evaluated these assumptions in light of similar assumptions made at other decommissioning projects.

ABZ then evaluated the projects included in the DCE to ensure that the collective scope of activities was sufficient to terminate the NRC license and restore the SONGS site. ABZ evaluated the costs of these projects against previous estimates and with comparable industry costs. In parallel with its review of projects, ABZ evaluated the schedule for these projects to ensure that sufficient time was allocated for successful performance, and to evaluate the ability to adjust the planned schedule to accommodate potential delays.

Separate from its review of decommissioning projects, ABZ evaluated undistributed costs in the DCE, including both staff costs as well as non-staff costs to ensure that all such costs were included and that the estimated costs were reasonable.

Finally, ABZ reviewed the contingency included in the DCE and the basis used to allocate contingency. ABZ evaluated the change in contingency from previous DCEs as well as the basis for such changes.

D. <u>ABZ Findings</u>

1. <u>Key Facts And Assumptions</u>

The 2017 SONGS 2&3 DCE contains a number of key facts and assumptions. ABZ reviewed these key facts and assumptions and concluded that the facts represent known conditions and that the assumptions are reasonable.

2. <u>Scope</u>

The SONGS DCE includes two major fixed-price contracts that cover a large portion of the work to remediate radiological hazards and reduce the footprint of the NRC license to that required to store spent fuel, and to transfer spent fuel on-site to a dry storage facility. Beyond these two major contracts, the DCE includes continued management of spent fuel until accepted by DOE, demolition of uncontaminated structures, and restoration of the site. ABZ reviewed this scope of work against previous SONGS DCEs including the 2014 DCE performed by Energy*Solutions* as well as previous ABZ estimates.

ABZ verified that the 2017 DCE included all identified activities needed to terminate the NRC operating license and restore the site consistent with the end-state assumptions.

3. <u>Schedule</u>

ABZ reviewed the schedule for decommissioning activities, identified critical path activities, and ability to manage delays in performance of major activities. ABZ compared this schedule to previous SONGS schedules and evaluated the proposed activity lengths to relative to recent decommissioning projects. ABZ concluded that the schedule allowed adequate time to complete required activities.

4. Risk Mitigation

ABZ reviewed both the contingency included in the 2017 SONGS 2&3 DCE as well as the schedule to determine whether and how uncertainties could be accommodated without an increase in project cost or duration. ABZ concluded that the schedule provided sufficient flexibility to allow for a delay in completing critical path activities while still maintaining the overall project schedule and keeping costs within the estimate total. Further, ABZ evaluated the overall contingency compared to the current state of the SONGS decommissioning project and concludes that the contingency is reasonable for the current project state.

E. Conclusion

ABZ concludes that the scope of the 2017 SONGS DCE is sufficient to terminate the NRC license and restore the site; that the projected schedule allows sufficient time for completion of all required activities; that the cost is reasonable for performance of those activities; and that sufficient risk mitigation has been included.

IV.

RECONCILIATION OF THE 2017 DCE TO THE 2014 DCE

A. Overview

In D.16-04-019, the Commission found reasonable the 2014 SONGS 2&3 DCE of $4,411 million (100% level, 2014 $). The 2017 SONGS 2&3 DCE estimates the total cost to decommission SONGS 2&3 will be $4,479 million (100% share, 2014 $). There are several variances between the 2014 and 2017 DCEs that net to small 1.5% increase in the 2017 DCE, as shown in Table IV-2 below.[20] At a high level, the increase is due to new scope not included in the 2014 DCE including ISFSI Aging Management Project and GTCC waste storage; the remaining variances essentially net to a zero change.

[20] Appendix C provides a table which shows the differences between Table 2 of the 2017 SONGS 2&3 DCE and this Table IV-2. SCE made these changes to be able to provide better description of the activities and variances.

Table IV-2
Reconciliation of 2017 DCE to 2014 DCE
(100% Share, Millions of 2014 $)

	Description	2017 DCE Total (2014 $)	2014 DCE Total (2014 $)	Variance
1	**Distributed Projects**			
2	ISFSI & Fuel Transfer Operations	$ 270.2	$ 405.1	$ (134.9)
3	Final Site Restoration	6.9	57.4	(50.5)
4	ISFSI Aging Management	36.5	-	36.5
5	Decontamination, Demolition, and Disposal	[redacted]	1,208.2	[redacted]
6	Substructure Removal	273.0	303.8	(30.8)
7	Other Projects	99.6	72.9	26.7
8	GTCC Waste Storage	26.6	-	26.6
9	Plant Easement/Lease Renewals	27.1	1.4	25.7
10	Offshore Conduit Removal	91.6	96.0	(4.4)
11	ISFSI Demolition	19.2	21.1	(1.9)
12	Completed Projects	123.3	98.1	25.2
13	**Distributed Subtotal**	**$** [redacted]	**$ 2,264.0**	**$** [redacted]
14				
15	**Undistributed Activities**			
16	Contracted Services	$ 225.2	$ 34.6	$ 190.6
17	Service Level Agreements	168.2	-	168.2
18	DGC Staffing	[redacted]	423.6	[redacted]
19	Labor-Staffing	986.2	1,029.4	(43.2)
20	All Other Non-Labor	623.6	659.6	(36.0)
21	**Undistributed Subtotal**	**$** [redacted]	**$ 2,147.2**	**$** [redacted]
22				
23	**Total**	**$ 4,478.6**	**$ 4,411.2**	**$ 67.4**

B. Distributed Projects

1. ISFSI & Fuel Transfer Operations

SCE retained Holtec as the vendor to construct sufficient additional dry spent fuel storage capacity for the fuel currently stored in the SONGS 2&3 spent fuel pools, and to transfer the fuel to dry storage. Holtec's ISFSI & Fuel Transfer Operations work scope includes the following activities:

- Design and license a seismically designed dry storage system for the 2,668 fuel assemblies that remain in the SONGS 2&3 spent fuel pools
- Excavate and install the foundation base mat
- Fabricate, transport, and install the 75 vertical canister enclosure containers (CECs)

- Install a perimeter form surrounding the CECs and backfill with concrete
- Install a protected area security perimeter around the new ISFSI
- Fabricate and transport 75 multi-purpose canisters (MPCs) and seal lids, two shielded transfer casks, canister sealing equipment, and cask transfer equipment to the SONGS site
- Re-certify the spent fuel pool cranes to ensure safe lifting of the fully loaded MPCs and transfer casks
- Perform dry-run testing of fuel loading, canister sealing, and canister drying in the spent fuel pools
- Perform dry-run testing of fully loaded MPCs/transfer casks from the SONGS 2&3 spent fuel pools to the ISFSI
- Load each MPC with up to 37 spent fuel assemblies and install MPC lid and drain line
- Remove each fully loaded MPC/transfer cask from spent fuel pool, decontaminate, weld MPC lid and leak test, dehydrate MPC interior and fill with helium, weld vent and drain ports and closure ring
- Transfer each fully loaded MPC/transfer cask from the spent fuel pool to the ISFSI
- Lower each MPC from the transfer cask into its CEC
- Install the closure lid on each CEC
- Construct stand-alone ISFSI security building

Based on SCE's contract with Holtec,[21] the cost to complete the ISFSI and Fuel Transfer Operations project is estimated in the 2017 DCE to be $270.2 million[22] (100% share, 2014 $). In the 2014 DCE, SCE estimated that the cost to expand the SONGS ISFSI and transfer all remaining fuel from the SONGS 2&3 spent fuel pools to the ISFSI was $405.1 million (100% share, 2014 $). Thus, the 2017 DCE reflects a decrease of $134.9 million. This decrease is attributable to the lower cost of the

[21] SCE selected Holtec after a competitive procurement process.

[22] *See* 2017 DCE, Appendix C, Table 2, line 37.

competitively bid Holtec contract relative to the 2014 DCE. Because SCE negotiated a substantial reduction relative to the previously estimated ISFSI and Fuel Transfer Operations costs, the Commission should find that the estimated cost is reasonable.

2. Final Site Restoration

The 2017 DCE includes the following scope for Final Site Restoration: (1) remove railroad tracks, gunite slope protection, site access roads, and parking lots; (2) perform final site grading and re-vegetation; and (3) perform any other work required by the Navy real estate authorization, which is expected to include end state requirements for the SONGS site.

The estimated cost for Final Site Restoration work in the 2017 DCE is $6.9 million[23] (100% share, 2014 $). The estimated cost for Final Site Restoration in the 2014 DCE was $57.4 million (100% share, 2014 $). This resulted in a cost decrease of $50.5 million (100% share, 2014 $). This cost decrease occurred because SCE consolidated two previously planned dewatering campaigns that would have been separated by nearly two decades into a single campaign that will occur near the end of the decommissioning schedule after SCE will have secured the final real estate authorization from the Navy and will know the Navy's final site restoration requirements. Final site restoration is a necessary part of the decommissioning process, and therefore, the Commission should find that these estimated costs are reasonable.

3. ISFSI Aging Management

The ISFSI Aging Management Program (AMP) project was established to develop inspection and maintenance programs for both the Areva and Holtec spent fuel dry storage systems.[24] The project also includes the cost to renew the NRC Certificates of Compliance (CoCs) for the storage systems. Areva and Holtec currently hold 20-year CoCs for their spent fuel dry storage systems used at SONGS. The Areva and Holtec CoCs will expire in 2023 and 2035, respectively. Under 10 C.F.R. § 72.240, the CoC holder may apply for renewal of the CoC for a term not to exceed 40 years. The CoC renewal applications must include Safety Analysis Reports (SARs) that provide descriptions of the

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[23] *See* 2017 DCE, Appendix C, Table 2, line 251.

[24] In September 2014, NEI 14-03 [Revision 0], *Guidance for Operations-Based Aging Management of Dry Cask Storage* was issued.

AMPs and time-limited aging analyses demonstrating that the structures, systems, and components important to safety will continue to perform their intended functions for the requested period of extended operation.

The estimated cost for the ISFSI Aging Management Program in the 2017 DCE is $36.5 million[25] (100% share, 2014 $). The 2014 DCE did not include a specific line item for the ISFSI Aging Management Program. This resulted in a cost increase of $36.5 million (100% share, 2014 $). As discussed above, these costs include initial cask testing, inspection equipment and licensing costs for dry cask CoC renewals and SAR updates for the Holtec and Areva AMPs.[26] These estimated costs are necessary to renew NRC required CoCs and therefore should be deemed reasonable by the Commission.

4. <u>Decontamination, Demolition, and Disposal</u>

The Decontamination, Demolition, and Disposal cost category includes many activities that will be performed by the DGC. As such, the pricing of these activities is primarily based on the executed SDS contract, which was achieved through a competitive procurement process that included multiple experienced contractors.[27] The work included in this category encompasses the removal and disposal of the necessary structures, systems, and components, as well as the removal of radiological and non-radiological contaminants necessary to meet the approved license termination plan. This category has been subdivided into the following major projects, consistent with the Milestone Framework:

- Initial D&D Activities – includes modifying the units' containment access to support future decommissioning activities; removing the missile shields and reactor heads; constructing an electrical ring bus for the site; and executing the necessary waste disposal contracts
- Reactor Vessel Internals (RVI) Segmentation and Disposal – includes designing and procuring the necessary RVI segmentation equipment; testing the specially

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[25] *See* 2017 DCE, Appendix C, Table 2, line 163.

[26] SCE will also incur undistributed non-labor costs for the ISFSI Aging Management Program for periodic maintenance and inspections of the spent fuel dry storage systems. Those costs are discussed in Section IV.C.5 below.

[27] *See* Exhibit SCE-05 for additional information regarding the DGC selection process.

engineered equipment and installing the equipment within containment; performing RVI segmentation; packaging GTCC waste; and disposing non-GTCC waste

- Spent Fuel Systems and Equipment Removal and Disposal – includes removing the spent fuel pool racks; installing a water processing system; and draining the spent fuel pools
- Steam Generator Removal and Disposal – includes removing the steam generators (two per unit); and segmenting, packaging, and disposing of the steam generators
- Non-Essential Systems Removal and Disposal – includes removing systems in multiple maintenance buildings, administration buildings, and warehouse buildings; and removing injection systems, condenser tubes, and auxiliary transformers
- Large Components Removal and Disposal – includes removing and disposing of reactor vessel insulation; and segmenting, packaging, and disposing of the reactor vessels, pressurizers, and turbine gantry cranes
- Initial Plant Buildings Demolition and Disposal – includes procuring building demolition equipment; and then demolishing the auxiliary control/radwaste building, full flow condensate polishing demineralizer and turbine buildings, emergency diesel generator buildings; transformer pads, administration/warehouse/shop (AWS) building, and numerous other support structures
- Buildings Decontamination – includes removing the remaining radioactive materials embedded within the concrete and steel surfaces, walls, and floors of the buildings in the SONGS radiological control area; and performing decontamination verification surveys to validate the effectiveness of the decontamination work performed
- Final Plant Buildings Demolition and Disposal – includes demolishing the buildings in the central area of the plant, (i.e., the fuel handling and penetration buildings); and removing the protective area pavement

- Offshore Conduits Diffusers and Risers Removal – includes preparing hydro-geological analysis; and removing specified vertical diffusers and risers from the two offshore intake conduits and the two offshore discharge conduits
- Containment Buildings Demolition and Disposal – includes de-tensioning and removing the containment building post-tensioning cables; and demolishing the containment and safety equipment buildings
- Site Backfill, Compaction, etc. – following the demolition of structures, systems, and components, backfilling and compacting the site to a specified grade to meet the interim end-state
- Final Site Radiological Survey and NRC License Termination (for Partial Site Release of SONGS 2&3 Site) – includes performing the final radiological site status survey in accordance with NRC guidelines; and developing and supporting the License Termination Plan
- Waste Taxes (pass-through)[28] – per the DGC contract, the SONGS Participants are responsible to pay the DGC for the actual waste taxes and fees invoiced to SDS based on the actual waste disposed

The estimated costs for Decontamination, Demolition, and Disposal activities are shown in Table IV-3 below:

[28] These costs are not included in the SDS contract, but have been estimated in the 2017 DCE. In the 2014 DCE, applicable waste taxes were included with the estimated costs for each distributed project.

Table IV-3
2017 SONGS 2&3 DCE
Decontamination, Demolition, and Disposal Costs
(100% Share, Millions of 2014 $)

	Description	2017 DCE Total (2014 $)
1	**Decontamination, Demolition, and Disposal**	
2	Initial D&D Activities	$ [redacted]
3	Reactor Vessel Internals Segmentation and Disposal	[redacted]
4	Spent Fuel Systems/Equipment Removal and Disposal	[redacted]
5	Steam Generator Removal and Disposal	[redacted]
6	Non-Essential Systems Removal and Disposal	[redacted]
7	Large Components Removal and Disposal	[redacted]
8	Initial Plant Buildings Demolition and Disposal	[redacted]
9	Building Decontamination	[redacted]
10	Final Plant Buildings Demolition and Disposal	[redacted]
11	Offshore Conduit Diffusers/Risers Removal	[redacted]
12	Containment Buildings Demolition and Disposal	[redacted]
13	Site Backfill, Compaction, etc.	[redacted]
14	Final Site Radiological Survey and NRC License Termination	[redacted]
15	Waste Taxes (pass-through)	[redacted]
16	**Decontamination, Demolition, and Disposal Total**	**$** [redacted]

In the 2017 DCE, the estimated cost for Decontamination, Demolition, and Dismantling activities is $[redacted][29] (100% share, 2014 $). In the 2014 DCE, the estimated cost for these activities was $1,208.2 million (100% share, 2014 $), resulting in an increase of $[redacted].[30] The primary reason for the increased cost is the addition of activities expected to be performed that are currently outside the scope of the SDS contract. [redacted]

[29] *See* 2017 DCE, Appendix C, Table 2, lines 8 and 50, 57, 66, 70, 75, 86, 108, 121, 130, 132, 134, 144, 149, and 153.

[30] SCE is not providing a line-by-line comparison and variance analysis of DGC contract values to the 2014 DCE, because such an analysis would not provide meaningful information given how the DGC contract values were determined. The SDS contract reflects negotiated terms and conditions regarding the contract pricing and timing of payments agreed to between SCE and SDS. The SDS contract also assumes a grouping and sequencing of work different than assumed in the 2014 DCE. Although a line-by-line variance analysis is not possible given these issues, SCE is able to compare the total costs of the scope included in the SDS contract to the same scope of work included in the DCE.

[redacted]. However, this increase in distributed project costs is more than offset by a $[redacted] (100% share, 2014 $) decrease in undistributed DGC staffing costs.[32] The combined variance of these two cost categories resulted in a net cost savings of $[redacted] (100% share, 2014 $) achieved by SCE through the competitive bidding process for the DGC contract. All of these activities are required to decommission SONGS 2&3. The Commission, therefore, should find that these estimated costs are reasonable.

5. Substructure Removal

As briefly described above, the removal of remaining non-contaminated substructures, which is now estimated to occur during 2046-2049, will be a large-scale project that will require the expertise of a qualified third-party vendor. SCE estimates that the cost to perform this work scope, including the disposal of waste materials, will be lower than the cost assumed in the 2014 DCE.

The 2017 DCE assumed the cost would be $273.0 million[34] (100% share, 2014 $), whereas the 2014 DCE assumed the cost for the Substructure Removal project would be $303.8 million (100% share, 2014 $), a decrease of $30.8 million. The decrease is due to the identification of a closer waste disposal location.

6. Other Distributed Projects

The Other Distributed Projects cost category includes many distributed cost activities that either were not included in the 2014 DCE or for which the work scopes were determined to have changed substantially between the 2014 DCE and the 2017 DCE.

Examples of such activities include:

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31 [redacted]

32 For further discussion of DGC Staffing and the variance against the 2014 DCE, see Section IV.C.3 below.

33 [redacted]

34 *See* 2017 DCE, Appendix C, Table 2, line 224.

- GTCC Disposal – Under the DOE Standard Contract, the DOE is obligated to accept and dispose of "spent nuclear fuel" and "high level waste." The courts have determined that GTCC is "high level waste," which DOE is obligated to accept and dispose of under the DOE Standard Contract, but have stated that that does not mean that the government will have to bear the cost of GTCC waste disposal alone. The courts have not provided a disposal cost.[35]
- Cyber Security Modifications – Under 10 C.F.R. § 73.54, SCE was required to develop a cyber security plan that addressed eight milestones to ensure certain digital assets, such as computer and communication systems and networks, are secure and protected.
- California Environmental Quality Act (CEQA) – Under CEQA, the CSLC, as lead agency, is required to evaluate the SONGS decommissioning project and prepare an Environmental Impact Report (EIR) in response to SCE's application to modify and extend the existing CSLC lease regarding the offshore conduits. The CEQA process began in 2015. The CSLC is expected to certify the EIR in late of 2018. The CCC is then expected to review an application for a CDP for SONGS decommissioning based on the EIR, as well as its own additional analysis. The CCC is expected to consider SCE's CDP application by the end of 2018. Following the receipt of the CDP, physical decommissioning of the plant can proceed.
- Mesa Site Turnover – SCE's Mesa lease from the Navy consists of five parcels.[36] Parcel 5 is on the west side of U.S. Interstate Highway 5 (I-5) and includes a security station to control access to Parcels 6 and 7. Parcels 6 and 7 are located on the east side of I-5 and along with Parcel 5 comprise the area known as the Mesa site. Parcels 8 and 9 include a parking lot and lay-down area on the west side of I-5 and abut the SONGS site. SCE currently estimates that Parcels 5, 6, and 7 will be returned to the

[35] *Yankee Atomic Electric Co. v. U.S.*, 536 F.3d 1268, 1278 (Fed. Cir. 2008).

[36] *See* Appendix E for map of the parcel locations.

Navy in 2021, and Parcels 8 & 9 will be retained until the end of decommissioning. As part of the process to return Parcels 5, 6, and 7 to the Navy, SCE must first assess the property and remediate SONGS-caused contamination to the extent necessary to obtain "No Further Action Letters" from the California Department of Toxic Substances Control (DTSC) indicating the property is available for unrestricted use.[37]

- Substructure Removal Contractor Procurement – In 2044, SCE will begin efforts to procure a contractor for the removal of SONGS substructures and placement of permanent backfill. Because the dewatering, shoring, excavation, removal, and backfilling of the substructures will be a very large and specialized work scope, SCE will incur the cost to undertake a competitive procurement process to identify and select a specialty vendor to perform this work.
- Coastal Development Permit Extensions – SCE holds a CDP for the storage of SONGS 2&3 spent fuel in the Areva ISFSI system until November 2022, and a separate CDP to store SONGS 2&3 spent fuel in the Holtec ISFSI system until 2035. Therefore, the 2017 DCE assumes SCE will need to obtain CDP extensions from the CCC for the Areva and Holtec ISFSI systems prior to the expiration of the permits in 2022 and 2035, respectively.
- ISFSI Coastal Development Permit (CDP) Settlement – In August 2017, SCE reached a settlement agreement with parties who challenged the CDP, wherein SCE agreed to incur up to $4.3 million (100% share, 2014 $) on commercially reasonable efforts to identify an offsite location for SONGS spent fuel storage.
- Future DCE Updates – Under the Decommissioning Act, SCE is required to periodically revise the DCEs to include descriptions of changes in regulation, technology, and economics affecting the estimate of costs; and of additions and

[37] On April 24, 2017, the DTSC issued a No Further Action Letter for Parcel 5. The efforts to assess and remediate contamination for Parcels 6 and 7 are ongoing. SCE continues to hold Parcel 5 because it provides access to Parcels 6 and 7.

deletions to nuclear facilities.[38] SCE submits such DCE updates to the Commission in NDCTP proceedings.

- North Industrial Area (NIA) Sump Modifications – The NIA sump (located on the site formerly occupied by SONGS 1) currently discharges to the SONGS 2&3 dilution water system. The SONGS 2&3 dilution water system will be retired by SDS, and therefore the discharge pathway for the NIA sump will need to be modified.

The estimated costs for the Other Distributed Projects category are shown in Table IV-4 below:

Table IV-4
Reconciliation of 2017 DCE to 2014 DCE
Other Distributed Projects
(100% Share, Millions of 2014 $)

	Description	2017 DCE Total (2014 $)	2014 DCE Total (2014 $)	Variance
1	**Other Projects**			
2	GTCC Disposal	$ 40.7	$ 50.6	$ (9.9)
3	Cyber Security Modifications	9.4	1.9	7.5
4	CEQA	7.9	2.7	5.2
5	Mesa Site Turnover	20.3	17.8	2.6
6	**Previously Included Project Subtotal**	**$ 78.3**	**$ 72.9**	**$ 5.4**
7				
8	Substructure Removal Contractor Procurement	$ 7.0	$ -	$ 7.0
9	Coastal Development Permit Extensions	5.2	-	5.2
10	ISFSI CDP Settlement	4.3	-	4.3
11	DCE Update	3.7	-	3.7
12	NIA Sump Modifications	1.1	-	1.1
13	**New Projects Subtotal**	**$ 21.3**	**$ -**	**$ 21.3**
14	**Other Projects Total**	**$ 99.6**	**$ 72.9**	**$ 26.7**

The total estimated cost for these Other Distributed Projects in the 2017 DCE is $99.6 million (100% share, 2014 $). The estimated cost for such Other Distributed Projects in the 2014 DCE was $72.9 million (100% share, 2014 $). Thus, the 2017 DCE includes a $26.7 million increase for the Other Distributed Projects category.

[38] Pub. Utilities Code § 8326.

After the development of the 2014 DCE, SCE determined that the cost to complete several of its Other Distributed Project work scopes would be different than estimated in 2014. For example, in the 2014 DCE SCE estimated that the disposal cost for GTCC waste would be $50.6 million (100% share, 2014 $) based on the highest published disposal rates for Class C low level radioactive waste (LLRW). In the 2017 DCE, however, SCE assumed that the disposal cost for a canister of GTCC waste would be comparable to the disposal cost for a canister of spent fuel. This resulted in an estimated GTCC disposal cost in the 2017 DCE of $40.7 million[39] (100% share, 2014 $), a decrease of $9.9 million.

With respect to Cyber Security-related work, the 2014 DCE included $1.9 million (100% share, 2014 $) and assumed the work would be completed in 2013. At that time, SCE believed that after SCE submitted the certifications of permanently ceased operations for SONGS 2&3, SCE would no longer be subject to the cyber security requirements of 10 C.F.R. § 73.54. However, SCE subsequently determined that the SONGS Cyber Security Plan was still required because it was described in the Physical Security Plan License Condition for SONGS 2&3. Other decommissioning plants had sought an exemption from the cyber security requirements, but the NRC had not yet approved those requests. It was prudent for SCE to wait for the NRC to review these requests and provide further guidance prior to SCE submitting an exemption request so as to avoid any protracted delays in the NRC's review process. In the meantime, SCE was obligated to comply with the requirements related to performing cyber security assessments, but not the more costly implementation aspects of the requirements. When the NRC indicated a willingness to grant such exemption requests, SCE submitted a License Amendment Request (LAR) to the NRC in June 2017, wherein SCE requested removal of the requirement to fully implement the SONGS Cyber Security Plan. At the end of 2017, the NRC granted approval for SONGS to remove the cyber security license condition, thus waiving the implementation requirements. Prior to the NRC's granting of the exemption, SCE had expended $9.4 million[40] (100%

[39] *See* 2017 DCE, Appendix C, Table 2, line 188.
[40] *See* 2017 DCE, Appendix C, Table 2, line 191.

share, 2014 $) to implement cyber security assessments. SCE included this recorded amount in the 2017 DCE, resulting in a $7.5 million increase over the amount estimated in the 2014 DCE.

With respect to the CEQA project, the 2017 DCE forecast $7.9 million[41] (100% share, 2014 $). The 2014 DCE forecasted this major project at $2.7 million (100% share, 2014 $), resulting in an increase of $5.2 million. The increase occurred because the time and effort required to complete this activity were greater than assumed during the development of the 2014 DCE. Specifically, SCE originally anticipated the CEQA review would be completed in approximately one year. Given the complexity of and varied interests (Navy, local communities, environmental advocates) that must be considered, SCE now anticipates that it will be nearly a four-year effort. SCE underestimated the level of effort necessary to complete the CEQA review, resulting in the variance. This activity is required in order to begin D&D.

With respect to Mesa Site Turnover project, the 2017 DCE forecast $20.3 million[42] (100% share, 2014 $). The 2014 DCE forecasted this major project at $17.8 million (100% share, 2014 $), resulting in an increase of $2.6 million. The increase occurred because the time and effort required to complete this activity were greater than assumed during the development of the 2014 DCE. Specifically, SCE originally expected to return the property to the Navy in 2017 with limited environmental characterization. Subsequently, the Navy imposed stringent remediation standards for the property requiring more extensive characterization and remediation, so turnover is now expected to occur in 2021. SCE must comply with the Navy's requirements.

The remaining Other Distributed Projects were not included in the 2014 DCE because their scopes emerged after the 2014 DCE was developed. SCE estimated their costs as follows:

Substructure Removal Contractor Procurement – The 2017 DCE includes costs of $7.0 million[43] (100% share, 2014 $) for a competitive bidding process to select a substructure removal contractor, including the development of a Request for Proposal, proposal evaluation, and contract

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[41] *See* 2017 DCE, Appendix C, Table 2, line 184.
[42] *See* 2017 DCE, Appendix C, Table 2, line 178.
[43] *See* 2017 DCE, Appendix C, Table 2, line 190.

award. The estimate is approximately one-half the cost to procure a DGC for the major D&D work because the scope of this effort is nearly half the scope of the DGC D&D work.

Coastal Development Permit (CDP) Extensions – The 2017 DCE includes costs of $5.2 million[44] (100% share, 2014 $) for SCE to obtain extensions for the Areva and Holtec CDPs. SCE holds a CDP to construct and operate the Areva ISFSI to store SONGS 2&3 spent fuel until November 2022, and a separate CDP to construct and operate the Holtec ISFSI to store SONGS 2&3 spent fuel until 2035. The 2017 DCE assumes SCE will need to obtain CDP extensions from the CCC for the Areva and Holtec ISFSI systems prior to the expiration of the permits in 2022 and 2035, respectively. SCE considered the recorded costs from past CDP applications and the complexities of the anticipated issues that will require evaluation in these two CDP extensions to estimate the cost to obtain these two CDP extensions.

ISFSI CDP Settlement – As part of the ISFSI CDP Settlement, SCE agreed to incur up to $4.0 million (100% share, nominal $) on commercially reasonable efforts to identify an offsite location for SONGS spent fuel storage. SCE also included $0.3 million (100% share, nominal $) for SCE outside counsel legal costs to reach the settlement.[45] SCE also included $0.8 million (100% share, nominal $) for attorney's fees to plaintiff's counsel, as agreed to in the settlement.[46] This $5.1 million (100% share, nominal $) increase was unforeseeable at the time the 2014 DCE was developed. This cost category was shared between SONGS 1 and SONGS 2&3. The amount allocated to SONGS 2&3 is $4.3 million (100% share, 2014 $). The settlement allowed SCE to proceed with transferring fuel to the ISFSI. It is also reasonable for SCE to explore offsite locations for the storage of spent fuel.

Future DCE Updates – SCE assumes a cost of $3.7 million[47] (100% share, 2014 $) to develop future DCE Updates because SCE now assumes that it will use a third-party vendor to develop

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[44] *See* 2017 DCE, Appendix C, Table 2, line 167.

[45] Given the ongoing analyses and the current uncertainty regarding the potential location and requirements for an acceptable alternative spent fuel storage site, the estimated cost to re-locate the SONGS 2&3 spent fuel to an alternative site are speculative and have not been included in the 2017 DCE.

[46] Under the California Civil Procedure Code, a prevailing plaintiff in a mandamus proceeding is entitled to seek recovery of attorney's fees. *See* Cal. Civ. Proc. Code § 1021.5.

[47] *See* 2017 DCE, Appendix C, Table 2, line 182.

the DCE Updates instead of preparing them in-house at an average cost of approximately $0.3 million (100% share, 2014 $) per update. Under the Decommissioning Act, SCE is required to periodically revise the DCEs and submit them to the Commission.

NIA Sump Modifications – The North Industrial Area (NIA) sump currently discharges to the SONGS 2&3 dilution water system. Because SDS will remove the dilution water system, the discharge path for the NIA sump must be modified. SCE provided an estimated cost of $1.1 million[48] (100% share, 2014 $) for this work scope.

Relative to the 2014 DCE, the cost increases for Other Distributed Projects described above are partially offset by the lower estimated cost to dispose of GTCC waste, and result in a net increase of $26.7 million (100% share, 2014 $). The Commission should find the increased estimated costs for the Other Distributed Projects reasonable because each of these projects is required to fulfill an unavoidable regulatory requirement or a contractual obligation.

7. <u>Greater Than Class C (GTCC) Waste Storage</u>

In the 2017 DCE, SCE assumes that it will be required to license and purchase ten new canisters for storing and disposing of GTCC waste from SONGS 2&3 D&D activities and will use two existing Areva canisters for storing GTCC waste from the spent fuel pools. In contrast, SCE assumed in the 2014 DCE that it would use the ten Areva canisters that were originally fabricated for storing and disposing spent fuel from SONGS 2&3. SCE made this change because, although the ten Areva canisters are licensed for storing and transporting spent fuel, they are not licensed for transporting GTCC waste.[49] Although the radiological and physical characteristics of spent fuel would seem to bound those of GTCC waste, SCE determined that the canisters may only be used for their intended (and licensed) purpose, and that they would need to be re-licensed before they could be used to store and transport GTCC waste. Because most of the GTCC waste generated at SONGS 2&3 will come from the reactor vessel internals segmentation project, which is scheduled near the beginning of D&D activities, and the time required to re-license the Areva canisters is uncertain, SCE determined that it would be

[48] *See* 2017 DCE, Appendix C, Table 2, line 192.

[49] The canisters can be used to store GTCC waste as long as the canister does not need to be modified. For these ten canisters, the canisters would need to be modified to store the GTCC from D&D activities.

imprudent to risk an unknown delay to the D&D schedule by allowing it to be constrained by an effort to re-license the Areva canisters. SCE determined that it would instead be more prudent to avoid such schedule uncertainties by obtaining ten new canisters that would already be licensed to store and transport GTCC waste.

The estimated cost for GTCC storage in the 2017 DCE is $26.6 million (100% share, 2014 $). The 2014 DCE did not include any costs for GTCC storage. This resulted in a cost increase of $26.6 million[50] (100% share, 2014 $). Nevertheless, the Commission should find this estimated cost increase reasonable because it will reduce the risk of substantially greater costs due to potential project delays resulting from a delay to re-license the Areva canisters for GTCC waste storage and disposal.

8. Plant Easement/Lease Renewals

SCE uses the land upon which the SONGS site is located pursuant to a grant of easement executed with the Navy in 1964. This easement expires in 2024. The Navy has informed SCE that the existing easement will not be renewed because the terms are outdated; therefore, a new real estate authorization will be negotiated. SCE anticipates that the new real estate authorization will: (1) modify land boundaries to exclude roads used by the public, exclude lands within the current easements that SCE does not use, include Parcels 8 and 9, and include lands that SCE occupies that are not within the current easements; and (2) include pricing that is consistent with the current fair market rental value of the property. The Navy will be required to perform a limited-scope NEPA review to issue this new real estate authorization. The public interest in the Navy's decision, mostly due to on-site spent fuel storage, may impact the extent of the Navy's NEPA review effort.

Due to the uncertainty of how long the spent nuclear fuel would be on-site and the potential for relocation of the ISFSI in 2035, the 2017 DCE conservatively assumes that SCE will have to negotiate real estate authorizations with the Navy two additional times. Therefore, the next real estate authorization will expire in 2035, requiring SCE to seek a renewal. It is assumed the terms and site use will remain the same, and that the term will also be 10 years. Thus, the cost for this effort is estimated to be less than for the previous negotiation. This effort will also require a limited-scope NEPA review.

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[50] *See* 2017 DCE, Appendix C, Table 2, line 169.

When the real estate authorization needs to be renewed again in 2045, SCE will request the Navy to specify the final site restoration and substructure removal requirements. SCE currently plans to commence this effort in 2040, such that the real estate authorization renewal and final site restoration and substructure removal requirements would be in place by 2045. This would facilitate performing the Substructure Removal civil works project during 2046-2049; and ISFSI decommissioning, NRC license termination, and final site restoration during 2050-2051. Because this real estate authorization renewal will identify the conditions under which the land will be returned to the Navy, the Navy will be required to perform a more robust NEPA review.

In the 2017 DCE, the estimated cost for Plant Easement/Lease Renewals is $27.1 million[51] (100% share, 2014 $). In the 2014 DCE, the estimated cost was $1.4 million (100% share, 2014 $). This results in an increase of $25.7 million. The 2017 DCE includes costs for SCE labor, contract support, Navy costs (such as consultations/review hours), surveys and mapping for three distinct real estate authorizations and three corresponding NEPA reviews. At the time the 2014 DCE was developed, discussions between SCE and the Navy had not yet progressed to that point that the need for three such updates to the Navy real estate authorization and three NEPA reviews was identified.

Because each of these updates to the Navy real estate authorization and any corresponding NEPA reviews will be required: (1) for SCE to fulfill the Navy's requirements for ongoing use of the SONGS site until SCE is ready to relinquish the land; (2) for the Navy to appropriately analyze and identify the final site restoration requirements; and (3) for SCE to implement the site restoration requirements to the satisfaction of the Navy, these Plant Easement/Lease Renewal costs are necessary decommissioning costs. SCE based the estimate on its recent history negotiating real estate matters with the Navy, as well as the costs incurred to date for SONGS real estate authorizations. Recent history with the Navy regarding the Mesa lease and the switchyard indicates that SCE's negotiations with the Navy will involve a lengthy and more complex undertaking than assumed in the 2014 DCE. The Commission, therefore, should find that these estimated costs are reasonable.

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[51] *See* 2017 DCE, Appendix C, Table 2, lines 185-187.

9. Offshore Conduits Removal

The 2017 DCE includes an estimated cost to perform the full removal of the SONGS 2&3 offshore conduits as estimated in the 2014 DCE.

The 2017 DCE includes $91.6 million[52] (100% share, 2014 $) to fully remove the SONGS 2&3 offshore conduits. In the 2014 DCE, the estimated cost was $96.0 million (100% share, 2014 $). This results in a decrease of $4.4 million. This decrease occurred because the estimated value in the 2014 DCE includes a 5% adder for A&G, whereas the A&G adder is excluded from the 2017 DCE estimated value.

10. ISFSI Demolition

Following the removal of all spent fuel and GTCC waste by the DOE, SCE will demolish and remove the ISFSI and perform activities necessary for the final restoration of the SONGS site.

The 2017 DCE includes $19.2 million[53] (100% share, 2014 $) for ISFSI decommissioning costs. In the 2014 DCE, the estimated cost was $21.1 million (100% share, 2014 $). This results in a decrease of $1.9 million. At the time the 2014 DCE was prepared, the specific plans to expand the ISFSI had not been defined. Later in 2014, SCE entered into a contract with Holtec to expand the ISFSI. The ISFSI demolition cost in the 2017 DCE is based on a new estimate completed by High Bridge Associates and reflects both the Areva and Holtec ISFSIs.

11. Completed Projects

During the period between the permanent retirement of SONGS 2&3 on June 7, 2013, and December 31, 2017, SCE completed several Distributed Projects. The following completed projects are some of those already submitted to the Commission for reasonableness review:

- Included in 2014 reasonableness testimony: (1) Development of the Certified Fuel Handler Program; (2) Post-Fukushima Modifications; (3) Independent Spent Fuel Storage Installation (ISFSI) Pad Study; and (4) Spent Fuel Pool Analyses.[54]

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[52] *See* 2017 DCE, Appendix C, Table 2, line 229.

[53] *See* 2017 DCE, Appendix C, Table 2, line 241.

[54] The SONGS 2&3 Distributed Projects completed during 2014 are explained in greater detail in A.16-03-004, Exhibit SCE-09 at pages 18-21.

- Included in 2015 reasonableness testimony: (1) Nuclear Fuel Contracts Cancellations; (2) Legacy Radwaste Disposal; (3) Security Programs – Security Shutdown Strategy; (4) Regulatory Submittals; (5) Historical Site Assessment/Site Characterization; and (6) Transition Project Modifications – Special Purpose Vehicle (SPV) Feasibility Study.[55]

The following completed projects are being submitted for reasonableness review in this proceeding:

- Major Projects completed during 2016-2017: (1) the Spent Fuel Islanding project; (2) Selection of Decommissioning General Contractor; and (3) Transition Project Modifications, including the Large Organism Exclusion Device Modification, Special Purpose Vehicle - Implementation, Records Retention Project, and the Simplification and Streamlining Project.[56]

The following completed activity will be submitted for reasonableness review in the 2021 NDCTP:

- Defueled Safety Analysis Report (DSAR): Updates the current licensing basis for the decommissioning configuration state of SONGS 2&3 and is a reference available for reviewing decommissioning actions and plans affecting the SONGS 2&3 site.

The estimated costs for the Completed Projects are shown in Table IV-5 below:

[55] The SONGS 2&3 Distributed Projects completed during 2015 are explained in greater detail in A.16-03-004, Exhibit SCE-08 at pages 26-39, and in Exhibits SCE-10 and SCE-10C.

[56] The SONGS 2&3 Distributed Projects completed during 2016-2017 are explained in greater detail in A.18-03-XXX, Exhibit SCE-05.

Table IV-5
Reconciliation of 2017 DCE to 2014 DCE
Completed Projects
(100% Share, Millions of 2014 $)

	Description	2017 DCE Total (2014 $)	2014 DCE Total (2014 $)	Variance
1	2014 Reasonableness Review	$ 0.6	$ 0.6	$ (0.0)
2	2015 Reasonableness Review	93.5	76.8	16.7
3	2018 Reasonableness Review	27.2	19.2	8.0
4	Future Reasonableness Reviews	2.0	1.5	0.5
5	**Completed Projects Total**	**$ 123.3**	**$ 98.1**	**$ 25.2**

The total estimated cost for these Distributed Projects, as reflected in the 2017 DCE, was $123.3 million[57] (100% share, 2014 $). In the 2014 DCE, the total estimated cost for the SONGS 2&3 decommissioning-related Completed Distributed Projects completed during 2013-2017 was $98.1 million (100% share, 2014 $), resulting in a variance of $25.2 million more than estimated. The explanations for the variances associated with each of these Distributed Projects are provided in the testimony SCE provided to the Commission in its reasonableness review submittals for each of these completed projects. The 2014 and 2015 completed projects are not being reviewed in this proceeding.

C. Undistributed Activities

1. Contracted Services

Contracted Services are shorter-term supplemental resources, specialty contractors and consultants, third-party services, materials, and supplies that are provided on an as-needed basis to support SONGS. SCE must meet several NRC regulatory requirements,[58] and maintain and operate SONGS to support spent nuclear fuel in the spent fuel pools and ISFSI. SCE also must meet contractual obligations and provide support services (such as engineering, regulatory, financial, and custodial services) for the plant and the general facility,[59] as well as provide basic office services, to complete

[57] *See* 2017 DCE, Appendix C, Table 2, lines 1, 12, 15, 18, and 24.

[58] *See* Exhibit SCE-01, Section 1.F.2.a, Nuclear Regulatory Commission Requirements.

[59] The general facility includes SONGS office buildings, roads, parking lots, fencing, lighting, and all the services necessary to maintain the site in a condition suitable for all the activities that are needed to decommissioning the plant.

decommissioning planning and implement decommissioning. SCE utilizes Contracted Services for these purposes.

Contracted Services in the 2017 DCE consists of two distinct types of costs, recorded and estimated:

- June 2013-2017 recorded costs of $83.7 million (100% share, 2014 $) equaling an approximate annual average of $18.6 million (100% share, 2014 $);[60] and
- 2018-2051 estimated costs of $141.5 million (100% share, 2014 $) reflecting an approximate annual average of $4.2 million (100% share, 2014 $).

The estimated cost for Contracted Services for 2018-2051 includes support activities for the organizations shown in Table IV-6 below.

Table IV-6
Contracted Services
(100% Share, Millions of 2014 $)

	Description	2017 DCE 2018-2051 Total (2014 $)	Annual Average Over 2018-2051 (2014 $)
1	**Contracted Services (2018-2051)**		
2	Decommissioning Oversight	$ 50.9	$ 1.5
3	Maintenance and Work Control	31.3	0.9
4	Nuclear Regulatory Affairs and Nuclear Oversight	22.7	0.7
5	Site Engineering	13.8	0.4
6	Site Management & Administration	10.7	0.3
7	Emergency Preparedness	6.3	0.2
8	Decommissioning Finance	4.8	0.2
9	Operations	1.0	0.0
10	**Contracted Services (2018-2051) Total**	**$ 141.5**	**$ 4.2**

SCE discusses each of these below:[61]

[60] Recorded costs during 2014-2015 were reviewed for reasonableness in the 2015 NDCTP, A.16-03-004. Recorded costs during 2016-2017 have been submitted for reasonableness review in this proceeding. *See* Exhibit SCE-05.

[61] Each of these organizations also incurs common costs for items such as employment related training, office supplies, custodial support, and employment related travel expenses.

- Decommissioning Oversight – Contracted services include EPRI support, document governance, engineering consulting services, estimating services for supply chain, and radiation protection and environmental contract support.
- Maintenance/Work Control – Service vendor support to perform preventive and corrective maintenance on all electrical systems; mechanical systems; instrumentation and controls systems; other plant systems still in operation; and the seawall.
- Nuclear Oversight/Nuclear Regulatory Affairs – Consultants to support Nuclear Regulatory Affairs' (NRA) interface with the NRC regarding SONGS' compliance with regulatory requirements, and to support Nuclear Oversight's execution of SONGS' decommissioning quality assurance program (DQAP).
- Site Engineering – Software licenses, security computer maintenance, and consultants as required to resolve specific issues being faced.
- Site Management and Administration – Staffing consultant to determine appropriate SONGS staffing levels.
- Emergency Preparedness – Contractor support for planning functions that continue to be required by federal regulations as long as nuclear fuel is stored on-site, including periodic drills to verify the effectiveness of the SONGS emergency preparedness program.

The total estimated cost for Contracted Services in the 2017 DCE is $225.2 million[62] (100% share, 2014 $). In the 2014 DCE, the total estimated cost for Contracted Services was $34.6 million (100% share, 2014 $). This resulted in an increase of $190.6 million. The 2014 DCE assumed Contracted Services would involve only office supplies, computers, and related equipment for utility staff use, based upon an assumed cost of $10,500 per year per employee. SCE utilized this category more broadly for the services and activities discussed above. Therefore, there is a variance

[62] *See* 2017 DCE, Appendix C, Table 2, line 287.

between the DCEs because the 2014 DCE did not include forecasts for this broader group of services and activities.

SCE developed the estimated Contracted Services costs in the 2017 DCE by analyzing the costs incurred for these functions in 2013-2016, and then built them up throughout the remaining decommissioning schedule (2018-2051) based on the anticipated future contracted services requirements for the SONGS decommissioning organization. SCE only included the costs necessary to meet its regulatory requirements related to the safe storage of spent fuel on-site; and to provide services required to maintain the plant and general facility. As noted above, the annual requirements going forward are substantially lower than those recorded during the initial decommissioning period and reflect the changed conditions, including SCE's transition of certain work activities to the DGC. The Commission should find that they are reasonable.

2. <u>Service Level Agreements/A&G</u>

Beginning in 2016, SONGS implemented annual intra-company Service Level Agreements (SLAs) with SCE corporate service providers (e.g., HR, IT, Real Estate, Supply Management, Treasurer's, Environmental, and Controller's). Each SLA describes the specific administrative and general (A&G) functions and services SCE provides to SONGS that support and sustain the D&D activities. The SLAs meet the terms and conditions included in the Decommissioning Agreement between SCE and the Participants.[63]

The 2014 DCE included an A&G adder (5.0%) that was applied to the costs of each DCE line item to cover the costs of SCE corporate departments supporting SONGS decommissioning. To maintain the integrity of the values referenced from the 2014 DCE in the variance explanations provided elsewhere in this testimony (i.e., all other cost categories), SCE kept the 5% A&G adder with each DCE line item in Table IV-2 above. This results in the value for the SLA/A&G in line 17 of Table IV-2 being shown as zero dollars in the 2014 DCE column. Rather than comparing the SLA/A&G amount included in the 2017 DCE to zero, it is more appropriate to compare it to the

[63] Section 8.1.7.2 of the SONGS Decommissioning Agreement, dated April 23, 2015.

corresponding 5% A&G adder from the 2014 DCE. The number SCE calculated for the corresponding 5% A&G adder from the 2014 DCE for the period 2016-2051 is $160.8 million (100% share, 2014 $).

The 2017 DCE incorporated the SLA costs to replace the A&G adders during the 2016-2028 period. Beginning in 2029, the 2017 DCE resumes applying the 5% A&G adder to all remaining decommissioning costs until project completion in 2051. Under this approach, the 2017 DCE estimates the cost of these SCE corporate functions at $168.2 million[64] (100% share, 2014 $), an increase of $7.4 million, in comparison to the corresponding 5% adder noted above. Using the combination of SLAs and A&G adder provides greater transparency and certainty of costs for the benefit of Participant oversight and project cost control. The Commission should find the estimated costs for the SLAs/A&G adder reasonable because they more accurately reflect the anticipated costs for these corporate support functions.

3. <u>DGC Staffing</u>

DGC staff consists of SDS personnel who provide the project management of the D&D work being performed by SDS, and manage/perform the programs and functions transferred from SCE to SDS. Their project management function involves the continued planning, scheduling, and monitoring of the D&D work as timely as possible while maintaining a safe work environment. It also includes contracting with third party specialty vendors to complete specific tasks (e.g. RVI segmentation), and administering those contracts. SCE provides oversight of SDS's project management. This division of labor allows SDS and SCE to utilize their core competencies to complete the work in an efficient manner – SDS's expertise in deconstructing facilities and SCE's oversight role. This cost category also includes staffing for a DGC that will be required during substructure removal and ISFSI D&D/final site restoration to be performed during 2046-2051.

In the 2017 DCE, the estimated cost for DGC Staffing is $[redacted][65] (100% share, 2014 $). In the 2014 DCE, the estimated cost for DGC Staffing was $423.6 million (100% share, 2014

[64] *See* 2017 DCE, Appendix C, Table 2, line 381.

[65] *See* 2017 DCE, Appendix C, Table 2, lines 155 and 386.

$). This resulted in a decrease of $[redacted] million. This primarily reflects the result of the competitive procurement process that resulted in the selection of SDS.

4. Labor-Staffing

SCE records costs for the SONGS utility staff and security force as undistributed labor. The SONGS utility staff performs various decommissioning activities relating to state and federal regulatory requirements, external communications with stakeholders, and strategic planning and analysis. The utility staff's activities include complying with existing technical specifications; ensuring the health and safety of the workers and the public; planning and preparing the facility for decommissioning; retiring plant systems to minimize or eliminate costs; and keeping the public and stakeholders informed on decommissioning progress. The security force protects SONGS in accordance with NRC regulations 10 C.F.R. § 73 and 10 C.F.R. § 50.54, and has been sized to meet the current design basis threat assessment, pursuant to 10 C.F.R. § 73.

In the 2017 DCE, SCE estimates that Labor-Staffing costs will be $986.2 million[66] (100% share, 2014 $). In the 2014 DCE, SCE estimated that Labor-Staffing costs would be $1,029.4 million (100% share, 2014 $). This resulted in a decrease of $43.2 million (100% share, 2014 $) relative to the 2014 DCE. Now that SCE has four plus years of experience with the planning of decommissioning, it is better able to identify the required staffing to safely carry out the decommissioning of SONGS 2&3 and oversight of its contractors. The estimated staffing levels in the 2017 DCE were developed through a collaborative process between SONGS executive managers and Kenrich. The staffing levels were subsequently vetted by ABZ. The Commission should find these costs reasonable as they reflect the additional experience SCE has gained, have been reviewed by an industry expert, and represent a well-supported estimate of the staffing levels required going forward.

5. All Other Non-Labor

Non-Labor costs include a wide range of decommissioning activities and obligations, including the following:

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[66] *See* 2017 DCE, Appendix C, Table 2, line 265.

- Site Lease and Easement Expenses – SCE will be required to make annual easement and lease payments to the Navy for the onshore plant site and SONGS Mesa facility and to the CSLC for the SONGS 2&3 offshore conduits until the easement and lease agreements are terminated.
- Severance – Under the Decommissioning Act, SCE is required to provide severance benefits to SCE employees at SONGS whose jobs are eliminated as a result of the permanent retirement of SONGS.
- Energy – SCE must purchase electrical energy at retail rates to power the SONGS site.
- Loading Spent Fuel & GTCC Waste to DOE – Under the DOE Standard Contract, SCE is responsible for the cost to transfer spent fuel canisters from the ISFSI and loading them into DOE shipping containers on-site, and then onto the DOE's transportation device.
- Information Technology – SCE will be required to incur software and network licenses, pay network service providers, and provide internal technical support to site personnel at levels commensurate with site staffing until decommissioning is completed.
- Third Party Legal – SCE retains outside counsel as necessary to handle legal matters that require specific expertise or additional resources.
- Emergency Preparedness Fees – SCE provides funding to local jurisdictional authorities for their radiological emergency preparedness, and will continue to do so until all spent fuel has been removed from SONGS, under a memorandum of understanding.
- NRC Fees – As holder of the NRC licenses for SONGS, SCE will be required to pay 10 C.F.R. Part 171 annual license fees and 10 C.F.R. Part 170 inspection fees until the NRC licenses are terminated.

- Utility Staff Health Physics Supplies – After SDS completes the major D&D work, SCE will re-assume responsibility for providing health physics supplies as required to support the ISFSI-only staff.
- Community Engagement Panel – SCE has chartered a panel consisting of a group of representatives from surrounding cities and counties to serve as a conduit of information to the public and other stakeholders regarding decommissioning that seeks to educate and explain SONGS decommissioning matters of interest to the local public. SCE incurs costs to conduct quarterly CEP meetings at venues in the vicinity of SONGS.
- Environmental Permits and Fees – SONGS must comply with a variety of environmental regulations and maintain several environmental permits that will require periodic payments of fees.
- ISFSI Aging Management –The facility maintenance and inspection activities for the ISFSI, in compliance with the Areva and Holtec SARs, as will be determined by the ISFSI Aging Management Program to be developed.
- Security Related Expenses – As long as spent fuel remains on-site, the SONGS security force will continue to require uniforms, weapons, ammunition, other supplies and equipment, as well as background investigations, training, and vendor support.
- DGC Executive Oversight Committee – a five person committee that provides oversight and resolves contractual issues regarding the SDS contract. SCE and SDS share the cost of three independent members on the committee.
- Insurance – NRC regulations require SCE to maintain minimum levels of nuclear liability and property insurance until the spent fuel is removed from the SONGS site. SCE also maintains general liability insurance and excess workers' compensation insurance.

- Association Fees and Expenses – NEI membership fees, and costs related to an external Nuclear Oversight Board (NOB) and an outside advisor to SCE's Internal Nuclear Management Group (INMG).
- Water – SCE is required to purchase potable and service water for the SONGS Site.
- Office Space – During major D&D activities, SDS will demolish all existing office space on the SONGS site and provide temporary office space as necessary. After Major D&D is completed, SCE will need to provide office space for the remaining employees.
- Decommissioning Advisor – One or more outside consultants who provide subject matter expertise regarding decommissioning regulatory issues, spent fuel storage, and project management.
- Ground Water Monitoring – SCE will be required to periodically sample, analyze, and monitor the ground water beneath the SONGS site.

The estimated costs for Non-Labor are shown in Table IV-7 below:

Table IV-7
Reconciliation of 2017 DCE to 2014 DCE
All Other Non-Labor
(100% Share, Millions of 2014 $)

	Description	2017 DCE Total (2014 $)	2014 DCE Total (2014 $)	Variance
1	**Non-Labor**			
2	Site Lease and Easement Expenses	$ 97.5	$ 19.5	$ 78.0
3	Severance	121.0	170.8	(49.8)
4	Energy	84.7	50.2	34.5
5	Loading Spent Fuel & GTCC Waste To DOE	30.6	-	30.6
6	Information Technology	31.9	6.6	25.3
7	Third Party Legal	23.8	-	23.8
8	Emergency Preparedness Fees	48.3	25.8	22.5
9	NRC Fees	31.2	53.6	(22.4)
10	Utility Staff Health Physics Supplies	3.7	25.8	(22.1)
11	Community Engagement Panel	12.5	34.0	(21.5)
12	Environmental Permits and Fees	6.7	27.1	(20.4)
13	ISFSI Aging Management	15.3	-	15.3
14	Security Related Expenses	11.8	18.8	(7.0)
15	DGC Executive Oversight Committee	3.7	-	3.7
16	Insurance	63.7	67.3	(3.6)
17	Association Fees and Expenses	8.6	11.0	(2.4)
18	Water	16.5	14.5	2.0
19	Office Space	1.7	-	1.7
20	Decommissioning Advisor	9.9	11.4	(1.5)
21	Ground Water Monitoring	0.5	-	0.5
22	Property Tax	-	74.7	(74.7)
23	DGC Non-Labor	-	35.9	(35.9)
24	Spent Fuel Maintenance	-	7.4	(7.4)
25	DAW Disposal	-	3.9	(3.9)
26	Tools and Equipment	-	1.3	(1.3)
27	**Non-Labor Total**	**$ 623.6**	**$ 659.6**	**$ (36.0)**

In the 2017 DCE, Other Non-Labor costs are estimated at $623.6 million[67] (100% share, 2014 $). In the 2014 DCE, Other Non-Labor costs were estimated at $659.6 million (100% share,

[67] *See* 2017 DCE, Appendix C, Table 2, line 375 (minus line 287 Contracted Services costs, which are discussed separately in Section IV.C.1).

2014 $). This resulted in a decrease of $36.0 million. This net decrease reflects numerous offsetting increases and decreases as explained below:[68]

- Site Lease and Easement Expenses – In the 2017 DCE, SCE estimates $97.5 million[69] (100% share, 2014 $) for site lease and easement expenses, compared with $19.5 million (100% share, 2014 $) in the 2014 DCE. This resulted in an increase of $78.0 million. SCE expects payments to the Navy to increase after the easement is renegotiated and the Navy resets the fees based on the current fair market rental value of the property.
- Severance – In the 2017 DCE, SCE estimates $121.0 million[70] (100% share, 2014 $) for employee severance costs, compared with $170.8 million (100% share, 2014 $) in the 2014 DCE. This resulted in a decrease of $49.8 million. SCE expects decreased severance costs because it has incurred lower than anticipated payouts to previously terminated SONGS employees. In addition, because many employees were reassigned to other positions within the company, they are no longer eligible for SONGS severance benefits.
- Energy – In the 2017 DCE, SCE estimates $84.7 million[71] (100% share, 2014 $) for energy costs compared with $50.2 million (100% share, 2014 $) in the 2014 DCE, resulting in an increase of $34.5 million. This variance reflects an updated forecast of energy usage levels (at retail energy rates) during 2019-2028 based upon how SDS plans to perform D&D.
- Loading Spent Fuel & GTCC Waste to DOE – In the 2017 DCE, SCE estimates that the cost to transfer spent fuel canisters from the ISFSI into DOE shipping containers

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[68] SCE is not providing variance analyses for variances ≤ $7.0 million or when the 2017 DCE did not include costs for items included in the 2014 DCE.

[69] *See* 2017 DCE, Appendix C, Table 2, line 358.

[70] *See* 2017 DCE, Appendix C, Table 2, line 353.

[71] *See* 2017 DCE, Appendix C, Table 2, line 308.

on-site, and then onto the DOE's transportation device, will be $30.6 million[72] (100% share, 2014 $). The 2014 DCE did not include a line item for this cost.

- Information Technology – In the 2017 DCE, SCE estimates $31.9 million[73] (100% share, 2014 $) for IT costs, compared with $6.6 million (100% share, 2014 $) in the 2014 DCE. This resulted in an increase of $25.3 million. The increased cost is due in part to some one-time payments to network service providers in 2018. After payment of these costs, SCE expects that ongoing support costs will be reduced after 2019.
- Third Party Legal – In the 2017 DCE, SCE estimates $23.8 million[74] (100% share, 2014 $) for third party legal expenses. This variance occurred because the 2014 DCE did not forecast these services as direct costs, but instead assumed that the costs were a part of overheads.[75] The services provided by outside legal counsel are required to perform normal business functions as well as tasks required by the NRC, and state and local agencies.
- Emergency Preparedness Fees – In the 2017 DCE, SCE estimates $48.3 million[76] (100% share, 2014 $) for emergency preparedness fees, compared with $25.8million (100% share, 2014 $) in the 2014 DCE. This resulted in an increase of $22.5 million. In the 2017 DCE, SCE anticipates that it will continue to incur emergency preparedness fees pursuant to a Memorandum of Understanding with local jurisdictional authorities until all spent fuel is removed from the SONGS site versus the assumption in the 2014 DCE that such payments would terminate when the spent fuel was removed from the pools.

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[72] *See* 2017 DCE, Appendix C, Table 2, line 361.

[73] *See* 2017 DCE, Appendix C, Table 2, line 325.

[74] *See* 2017 DCE, Appendix C, Table 2, line 336.

[75] Corporate support is provided by SCE from organizations other than SONGS (e.g., legal, treasurer's, finance, IT, supply chain).

[76] *See* 2017 DCE, Appendix C, Table 2, line 303.

- Utility Staff Health Physics Supplies – In the 2017 DCE, SCE estimates $3.7 million[77] (100% share, 2014 $) for utility staff health physics supplies, compared with $25.8 million (100% share, 2014 $) in the 2014 DCE. This resulted in a decrease of $22.1 million. The decreased cost occurred because SDS will be performing the health physics functions for the major D&D work, and incurring the cost of its health physics supplies. SCE will re-assume responsibility for providing health physics supplies after the major D&D work is completed, as required to support the ISFSI-only staff.
- Community Engagement Panel (CEP) – In the 2017 DCE, SCE estimates $12.5 million[78] (100% share, 2014 $) for Community Engagement Panel expenses, compared with $34.0 million (100% share, 2014 $) in the 2014 DCE. This resulted in a decrease of $21.5 million. The decreased cost occurred because SCE has incurred lower CEP costs than estimated in the 2014 DCE and expects similar CEP expenditures in the future.
- NRC Fees – In the 2017 DCE, SCE estimates $31.2 million[79] (100% share, 2014 $) for NRC fees, compared with $53.6 million (100% share, 2014 $) in the 2014 DCE. This resulted in a decrease of $22.4 million. The decreased estimated cost occurred because the NRC reduced its 10 C.F.R. Part 171 annual license fees, and SCE expects to incur lower NRC inspection costs under 10 C.F.R. Part 170 than previously estimated.
- Environmental Permits and Fees – In the 2017 DCE, SCE estimates $6.7 million[80] (100% share, 2014 $) for environmental permits and fees, compared with $27.1 million (100% share, 2014 $) in the 2014 DCE. This resulted in a decrease of $20.4 million. The decreased estimated cost occurred primarily due to a reduction to

[77] *See* 2017 DCE, Appendix C, Table 2, line 373.
[78] *See* 2017 DCE, Appendix C, Table 2, line 280.
[79] *See* 2017 DCE, Appendix C, Table 2, line 340.
[80] *See* 2017 DCE, Appendix C, Table 2, line 313.

the annual NPDES Permit fees. Due to a reduction in the quantity of discharges from the plant associated with the permanent shutdown, SCE was able to negotiate with the SWRCB a reduction to the annual NPDES permit fees from $1.1 million per year to $0.2 million per year. In addition to the reduced NPDES fees, the other environmental fees (e.g., hazardous waste, pollution fees) were less than estimated in the 2014 DCE. The 2014 DCE was prepared before the impact of decommissioning on the fees assessed by various local and state agencies was determined.

- ISFSI Aging Management – In the 2017 DCE, SCE estimates $15.3 million[81] (100% share, 2014 $) for undistributed ISFSI Aging Management expenses. The 2014 DCE did not include a line item for this cost.

The total net variance for Other Non-Labor costs is a decrease of $36.0 million (100% share, 2014 $). Because these estimated costs are necessary to complete decommissioning and reflect SCE's experiences throughout four plus years of decommissioning and incurring these types of costs, the Commission should find these estimated costs reasonable.

[81] *See* 2017 DCE, Appendix C, Table 2, line 270.

V.

CONCLUSION

The 2017 DCE estimates that the total cost to decommission SONGS 2&3 will be $4,479 million (100% share, 2014 $), an increase of approximately 1.5% over the 2014 DCE that the Commission found reasonable in D.16-04-019.

In Chapter II of this testimony, SCE presented a detailed discussion of the methodology by which the 2017 DCE was developed and the bases for its underlying assumptions. SCE also explained that due to the existence of contract pricing for much of the decommissioning work, SCE was able to reduce the overall contingency factor of the 2017 DCE from 25% to 17%. In Chapter III, SCE presented the testimony of Mr. Nicholas Capik, the Managing Director of ABZ Incorporated, a major provider of decommissioning cost estimates for U.S. nuclear facilities. Mr. Capik described the independent review that he performed regarding the completeness and accuracy of the 2017 DCE. In Chapter IV, SCE provided a detailed reconciliation of the 2017 DCE to the 2014 DCE, including detailed discussions of significant cost changes between the two estimates.

Given SCE's thorough and detailed explanation of the 2017 DCE, SCE has met its burden to demonstrate that the 2017 DCE is a reasonable estimate of SONGS 2&3 decommissioning costs, and provides an appropriate basis for the Commission to evaluate the reasonableness of the decommissioning costs. The Commission, therefore, should find the 2017 SONGS 2&3 DCE to be reasonable.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF JOSE LUIS PEREZ

Q. Please state your name and business address for the record.

A. My name is Jose Luis Perez, and my business address is 2244 Walnut Grove Ave, Rosemead, CA 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Principal Manager, Nuclear CPUC Regulatory Affairs and Compliance, in the Regulatory Affairs Organization responsible for CPUC regulatory activities and financial planning & analysis for SONGS issues.

Q. Briefly describe your educational and professional background.

A. I earned an MBA from the University of California, Irvine in 1997. I earned a Bachelor of Science Degree in Civil Engineering from California State University, Long Beach in 1977. I am a Registered Professional Engineer in the State of California. Since joining Edison in 1982, I have held various management positions in nuclear generation business, finance, regulatory affairs, planning & strategy, and project controls organizations. In addition, I have managed various projects, including SONGS 1 decommissioning shortly after permanent shutdown and industry restructuring financial analysis. Prior to joining Edison, my professional background included various home office and jobsite positions in the civil engineering, nuclear power plant start-up, and project controls organizations of Bechtel Power Corporation and the collection and analysis of construction cost data for publication in cost estimating manuals for Marshall and Swift Publications.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Exhibit SCE-03: *Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3*, as identified in the Table of Contents thereto.

1 Q. Was this material prepared by you or under your supervision?
2 A. Yes, it was.
3 Q. Insofar as this material is factual in nature, do you believe it to be correct?
4 A. Yes, I do.
5 Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best
6 judgment?
7 A. Yes, it does.
8 Q. Does this conclude your qualifications and prepared testimony?
9 A. Yes, it does.

ABZ, INCORPORATED

QUALIFICATIONS AND PREPARED TESTIMONY

OF NICHOLAS J. CAPIK

Q. Please state your name and business address for the record.

A. My name is Nicholas Joseph Capik, and my business address is 4451 Brookfield Corporate Drive, Suite 107, Chantilly, VA 20151.

Q. Who is your current employer?

A. ABZ, Incorporated.

Q. Briefly describe your present responsibilities at ABZ.

A. I am a Managing Director of ABZ. In that role, I am responsible for the management and execution of numerous ABZ projects performed for the nuclear industry.

Q. Briefly describe your educational and professional background.

A. I earned an BS in Mathematics from the Pennsylvania State University in 1983. I completed the Navy Nuclear Training Program in 1985. I served in the U.S. Navy from 1983 through 1991. Since 1991, I have been employed at ABZ. At ABZ, I have performed cost estimates for over 40 clients related to due diligence, decommissioning, accident cleanup, and site restoration. In this role, I was responsible for the development of assumptions, the selection of scenarios, the preparation of studies, and the presentation of results. I have supported litigation related to spent fuel storage, and tax issues related to decommissioning. I have had oversight and involvement of decommissioning activities at several nuclear facilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-03: *Testimony On The 2017 Decommissioning Cost Estimate for SONGS 2&3*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

1 A. Yes, I do.

Appendix B

Decommissioning Cost Estimate - Confidential

San Onofre Nuclear Generating Station Units 2 & 3
2017 Decommissioning Cost Estimate

Prepared For:
Southern California Edison
2244 Walnut Grove Avenue
Rosemead, CA 91770

Prepared By:
The Kenrich Group LLC
1919 M Street, NW
Suite 620
Washington, DC 20036

January 26, 2018

Revised March 8, 2018

Christopher F. Tierney
Vice President & Chief Financial Officer

DESCRIPTION OF MINOR REVISION

Revision Number: 1

Effective Date: March 8, 2018

The revisions made to the 2017 SONGS 2&3 Decommissioning Cost Estimate are minor in nature and do not revise or otherwise impact the content or results of the cost estimate.

Item 1 – The Spent Fuel Shipping Schedule in Appendix A has been revised to correct the number of Units 2 & 3 canisters transferred to the ISFSI.

Item 2 – Revised an activity description in Appendix B, "Detailed Project Schedule."

Item 3 – Within Appendix C, "Detailed Cost Tables," the notes to Appendix C have been attached.

Item 4 – The line numbers in Table 10, "Utility & Security Force Average Staffing By Period," have been corrected.

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Acronyms and Abbreviations

APCD	Air Pollution Control District
CCC	California Coastal Commission
CoC	Certificate of Compliance
CDP	Coastal Development Permit
CEQA	California Environmental Quality Act
CEP	Community Engagement Panel
CFR	Code of Federal Regulations
CPUC	California Public Utilities Commission
CSLC	California State Lands Commission
D&D	Decontamination & Dismantlement
DCE	Decommissioning Cost Estimate
DGC	Decommissioning General Contractor
DOE	U.S. Department of Energy
DTSC	California Department of Toxic Substances Control
EIR/EIS	Environmental Impact Report/Statement
GTCC	Greater Than Class C
HP	Health Physics
INMG	SCE Internal Nuclear Management Group
ISFSI	Independent Spent Fuel Storage Installation
LLC	Limited Liability Company
LLRW	Low-Level Radioactive Waste
NDCTP	Nuclear Decommissioning Cost Triennial Proceeding
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NIA	North Industrial Area
NOB	Nuclear Oversight Board
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
PG&E	Pacific Gas and Electric Company
PSDAR	Post-Shutdown Decommissioning Activities Report
SAR	Safety Analysis Report
SCE	Southern California Edison Company
SDS	SONGS Decommissioning*Solutions*
SONGS	San Onofre Nuclear Generating Station
WBS	Work Breakdown Structure

I. Executive Summary

The 2017 San Onofre Nuclear Generating Station Units 2&3 (SONGS 2&3) Decommissioning Cost Estimate (2017 DCE) has been prepared by the Kenrich Group LLC[1] (Kenrich) for Southern California Edison Company (SCE).[2] ABZ, Inc. (ABZ) also performed an independent review of the 2017 DCE.

The 2017 DCE utilizes the same Work Breakdown Structure (WBS) and selected distributed cost estimates included in the 2014 SONGS 2&3 DCE (2014 DCE) prepared by Energy*Solutions*, and essentially is an update to that DCE. The 2017 DCE will be submitted for review by the California Public Utilities Commission (CPUC) in the 2018 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP). SCE will also submit certain information contained in the 2017 DCE to the U.S. Nuclear Regulatory Commission (NRC) for its review.[3]

The 2017 DCE incorporates pricing from two significant contracts SCE has entered into for SONGS 2&3 decommissioning. In December 2014, SCE awarded a contract to Holtec International, Inc. (Holtec) to expand the SONGS Independent Spent Fuel Storage Installation (ISFSI) and transfer fuel from the SONGS 2&3 spent fuel pools to the ISFSI (ISFSI Expansion and Fuel Transfer Operations contract). In December 2016, SCE entered into a contract with the companies that have formed a joint venture called SONGS Decommissioning*Solutions* (SDS)[4], who will serve as the Decommissioning General Contractor (DGC) for major decontamination and dismantlement (D&D) activities. The ISFSI expansion project is in process, with transfer of spent fuel from the SONGS 2&3 spent fuel pools to the ISFSI planned to commence in 2018. SDS initially mobilized in January 2017, and is continuing to develop decommissioning plans and schedule. The DGC is currently expected to begin physical work in January 2019, following the approval of a Coastal Development Permit (CDP) by the California Coastal Commission (CCC). The 2017 DCE incorporates the pricing from both of these contracts.

In addition, the 2017 DCE incorporates and reflects recorded costs, new information, and experience gained from decommissioning activities SCE has completed since June 2013. Since announcing its decision in June 2013 to permanently retire SONGS 2&3, SCE has commenced preliminary decommissioning planning and performed other significant preparatory activities for

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[1] Kenrich is a national management consulting firm with significant experience in power plant construction and decommissioning and in the energy industry more broadly in the United States and internationally.

[2] Per the SONGS Decommissioning Agreement dated April 23, 2015, Southern California Edison is currently the Decommissioning Agent acting on behalf of itself and the three other SONGS 2&3 Participants, including San Diego Electric & Gas Company, the City of Riverside, and the City of Anaheim.

[3] In accordance with 10 C.F.R. § 50.82(a)(8)(v), the licensee must annually submit to the NRC by March 31 a financial assurance status report.

[4] The contract is between Southern California Edison Company and Energy*Solutions* Services, Inc. and AECOM Energy & Construction, Inc., together the "contractor," and referred to herein as "SDS."

SONGS 2&3 decommissioning. The 2017 DCE incorporates recorded costs through September 2017 associated with these efforts.

The 2017 DCE for SONGS 2&3 is $4.702 billion in Nominal/2017 dollars. The 2014 DCE was $4.411 billion in 2014 dollars. For purposes of comparison to the 2014 DCE, the 2017 DCE expressed in 2014 dollars is $4.479 billion, which results in an approximate $68 million variance (less than 2%) between the two DCEs.

II. Introduction

A. Purpose And Scope Of 2017 DCE

In accordance with the California Nuclear Facilities Decommissioning Act of 1985 (Act), SCE is required by the CPUC to update the SONGS 2&3 DCE every three years in connection with the NDCTP. The DCE is reviewed by the CPUC to determine the sufficiency of SCE's and San Diego Gas & Electric Company's (SDG&E) nuclear decommissioning trust funds, and the amount of customer contributions to those trust funds, if any are required. The DCE is also used in subsequent CPUC reasonableness reviews of actual decommissioning costs.

On June 7, 2013, SCE announced its decision to cease power generation operations and permanently retire SONGS 2&3.[5] In 2014, SCE engaged Energy*Solutions* to "evaluate decommissioning alternatives and assist in the development of a detailed project schedule and DCE to support the preparation and submittal of a Post Shutdown Decommissioning Activities Report (PSDAR) in accordance with 10 C.F.R. § 50.82(a)(4)(i), which requires that a PSDAR be submitted [to the NRC] within two years following the permanent cessation of operations."[6] SCE submitted the PSDAR and 2014 DCE to the NRC on September 23, 2014 and to the CPUC on December 10, 2014.[7] The CPUC approved the 2014 DCE as reasonable in Decision (D.) 16-04-019 issued on April 21, 2016.

In 2017, SCE engaged Kenrich to prepare the 2017 DCE to reflect the actual costs and updated information and experience gained from SCE's decommissioning activities completed since June 2013. The 2017 DCE will be reviewed by the CPUC for the purposes identified above. New and updated information incorporated into the 2017 DCE includes: [8]

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[5] SONGS 1 has largely been decommissioned and the site it occupied is now referred to as the North Industrial Area, which includes the SONGS ISFSI.

[6] Energy*Solutions*, "2014 Decommissioning Cost Analysis of the San Onofre Nuclear Generating Station Units 2&3," September 5, 2014.

[7] The NRC accepted the SONGS 2&3 PSDAR and found the 2014 Units 2&3 DCE estimate of $4.411 billion to be reasonable on August 20, 2015.

[8] Information in this DCE is intended to be current as of approximately September 30, 2017.

- The contract pricing for the contract awarded to Holtec International, Inc. (Holtec) for the ISFSI expansion and the transfer of spent fuel from the SONGS 2&3 spent fuel pools to the ISFSI;
- Contract value for the DGC contract awarded to SONGS Decommissioning*Solutions* (SDS) for the decontamination and dismantlement of SONGS 2&3, and the removal and disposal of hazardous and non-hazardous waste off the site;[9]
- Recorded costs for decommissioning activities through September 30, 2017;
- Revised U.S. Department of Energy (DOE) spent fuel acceptance date to reflect the DOE's continued failure to perform its contractual obligation to remove spent fuel from commercial nuclear reactors in the past four years;
- Revised environmental permitting approval dates based on the current permitting status and the requirements of the California Environmental Quality Act (CEQA) and the CCC's CDP processes;
- Revised project execution strategy to delay substructure removal until 2046;
- Updated undistributed cost projections based on historical recorded costs and revised projections;
- Updated ISFSI demolition costs to reflect the Holtec ISFSI pad; and
- Additional costs not included in the 2014 DCE.

In sum, significant components of the 2017 DCE are now based on competitively bid contracts, as well as three additional years of experience managing a decommissioning plant and overseeing decommissioning personnel. Where new information was not available, Kenrich worked with SCE personnel and third-party consultants to validate and refine the 2014 DCE cost and schedule assumptions. Table 1 and Figure 1 below provide a summary of the 2017 DCE in nominal/2017 dollars[10] and in 2014 dollars.

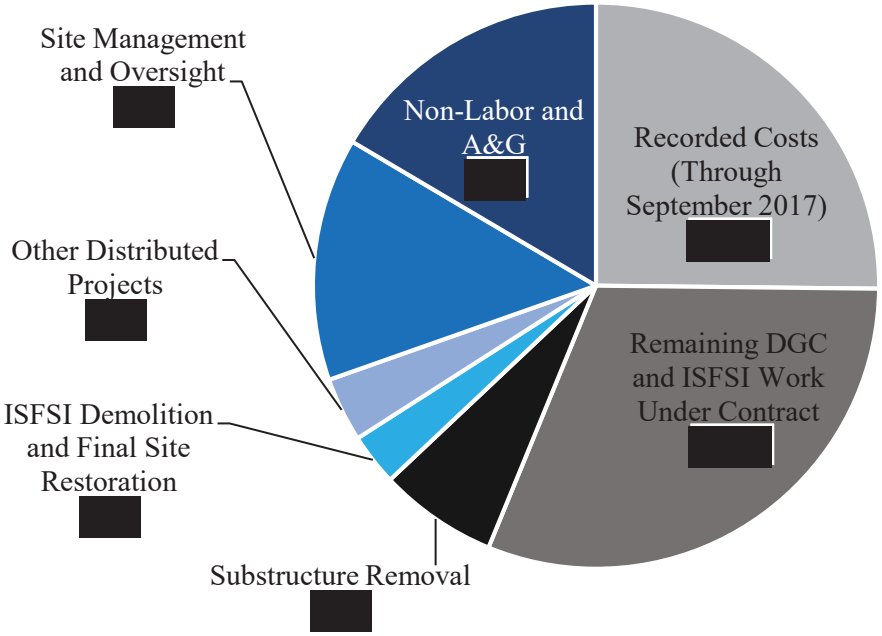
[9] See Appendix B for the schedule and activities for decontamination, and dismantlement.

[10] The 2017 DCE presents recorded costs in nominal dollars and estimated (i.e., October 2017-2051) costs in 2017 dollars.

TABLE 1 – 2017 DCE BY UPDATE CATEGORY [11, 12]
($ IN THOUSANDS)

	Description	2017 DCE (Nominal/ 2017$)	2017 DCE (2014$)
1	Recorded Costs (Through September 2017)	[redacted]	[redacted]
2	Remaining DGC and ISFSI Work Under Contract	[redacted]	[redacted]
3	Substructure Removal	[redacted]	[redacted]
4	ISFSI Demolition and Final Site Restoration	[redacted]	[redacted]
5	Other Distributed Projects	[redacted]	[redacted]
6	Site Management and Oversight	[redacted]	[redacted]
7	Non-Labor and A&G	[redacted]	[redacted]
8	**Total**	**$ 4,702,264**	**$ 4,478,566**

FIGURE 1 – 2017 DCE BY UPDATE CATEGORY
($ IN MILLIONS OF 2017 DOLLARS)



[11] Totals in tables throughout this report may not tie due to rounding.

[12] Of the $1,183,601 (nominal dollars) in recorded costs included in the 2017 DCE, $964,996 was recorded between June 2013 and December 2016, and $218,605 was recorded between January and September 2017 ($964,996 + $218,605 = $1,183,601).

B. Regulatory Framework

SONGS 2&3 decommissioning is governed by the following NRC regulations:

1. 10 C.F.R. Part 50 License – SCE holds a 10 C.F.R. Part 50 license for SONGS 2&3. SCE, as the license holder, must comply with all the requirements and standards of the Part 50 license. The Part 50 license authorizes SCE to store spent fuel on-site in wet storage (i.e., the spent fuel pool).

2. 10 C.F.R. Part 72 License – SCE is required to hold a 10 C.F.R. Part 72 license in order to store fuel on-site in dry storage at the ISFSI. The current ISFSI Part 72 license is a general license set forth in 10 C.F.R. § 72.210 and requires the possession of a Part 50 license.

3. 10 C.F.R. § 50.75(c) specifies the reporting and recordkeeping requirements for decommissioning planning and requires that the licensee provide adequate funding for termination of the Part 50 license.

4. 10 C.F.R. § 72.30 specifies the financial assurances and recordkeeping for decommissioning and requires that the licensee provide adequate funding for termination of the Part 72 license.

5. 10 C.F.R. § 50.54(bb) requires the licensee to submit written notification to the NRC within two years following permanent cessation of operation of the reactor or five years before expiration of the operating license(s), whichever occurs first, for review and preliminary approval of the program by which the licensee intends to manage and provide funding "for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository." The 2014 DCE was submitted pursuant to this requirement.

C. SONGS Decommissioning Background

SONGS is located in southern California on the shore of the Pacific Ocean, approximately 62 miles southeast of Los Angeles and 51 miles northwest of San Diego. The plant is located entirely within Marine Corps Base Camp Pendleton on land owned by the U.S. Department of the Navy (Navy), except for the offshore intake and outfall conduits. SONGS 2&3 occupy approximately 53 acres of the 84-acre SONGS site. Approximately 16 acres are occupied by the North Industrial Area (NIA), formerly the SONGS 1 site, which is where the ISFSI is located. Additional SONGS support activities occurred on Navy property across Interstate 5 from the SONGS site, referred to as the Mesa site.

SONGS 2&3 was a 2,250-megawatt nuclear generation facility consisting of two pressurized water reactors, which commenced operation in 1983 and 1984, respectively. On June 7, 2013, SCE announced plans to permanently retire SONGS 2&3. On June 12, 2013, SCE

submitted a Certification of Permanent Cessation of Power Operations to the NRC, certifying that SCE had permanently ceased power operations of SONGS 2&3, and surrendering SCE's authority to operate the units. SCE submitted to the NRC a Certification of Permanent Removal of Fuel for Unit 3 on June 28, 2013, and for Unit 2 on July 22, 2013. As a result of these submittals, SCE now holds an NRC license that does not permit power operations, but authorizes the possession of the SONGS facilities and licensed nuclear material.

As noted above, SCE has completed preliminary planning and performed other significant preparatory activities associated with SONGS 2&3 decommissioning. These activities include: (1) expanding the on-site spent fuel dry storage facility (also referred to as the ISFSI) and beginning preparations to transfer fuel from the spent fuel pools to the ISFSI; (2) planning the major decontamination, dismantlement, demolition and disposal efforts; (3) selecting a DGC to complete major portions of the decommissioning project, including the decontamination and dismantlement of SONGS 2&3, and removal and disposal of hazardous and non-hazardous waste from the site; (4) obtaining necessary approvals of various NRC license amendments now that SONGS 2&3 is permanently retired and being decommissioned; and (5) implementing various site projects to comply with regulatory requirements and other obligations, and prepare the site for major decommissioning activities.

Along with these efforts, SCE's legal and environmental teams have been working to complete the CEQA process and obtain a CDP so that major decontamination and dismantlement work by SDS can begin.

The current Grant of Easement for SONGS from the Navy is scheduled to expire May 11, 2024. Efforts to obtain a new real estate authorization from the Navy for the plant site are ongoing, and approval for the issuance of a new real estate authorization is expected by 2024.

D. The Kenrich Group

Kenrich is a national management consulting firm with substantial experience in the public utility industry, nuclear power plant construction and decommissioning, and other commercial and public construction projects. Kenrich professionals have prepared and sponsored expert testimony with respect to cost and schedule analyses, project management, and economic damages before state and federal courts, domestic and international arbitration tribunals, and state utility commissions.

Kenrich personnel have consulted with utilities for more than 30 years on a wide range of matters, including strategic planning and financial analyses to support management decision-making, reviews and investigations by state and federal regulatory commissions, and economic damages analyses in the context of business disputes. Kenrich's consultants include accountants, financial analysts, and engineers, and the firm typically focuses on complex and detailed accounting and financial issues, as well as cost and schedule performance on major projects, including nuclear power plant construction and decommissioning.

III. Summary of the 2017 DCE

A. General Approach

This 2017 DCE builds on the 2014 DCE, incorporating recorded costs through September 30, 2017; contract pricing for the ISFSI expansion contract awarded to Holtec in December 2014 and the DGC contract awarded to SDS in December 2016; site restoration costs estimated by third-party engineering firms; and revised SCE estimates for ongoing plant security and maintenance, and project oversight. Kenrich worked closely with SCE management and project oversight to develop the 2017 DCE. This DCE is generally consistent with the guidance provided in NRC Regulatory Guide 1.202, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors."

SCE retained ABZ, Incorporated (ABZ) to perform an independent review of the 2017 DCE. ABZ is a management consulting and engineering firm specializing in providing services related to decommissioning costs, scheduling, and spent fuel storage. ABZ has prepared decommissioning cost estimates for numerous nuclear plant owners, including an estimate of SONGS 2&3 decommissioning costs for SCE in 2013, shortly following the announcement of the permanent retirement of SONGS 2&3.

B. Energy*Solutions* 2014 DCE

In January 2014, SCE retained Energy*Solutions* to evaluate decommissioning alternatives and assist in the development of a detailed project schedule and DCE to support the preparation and submittal of a PSDAR in accordance with 10 C.F.R. § 50.82(a)(4)(i), which requires that a PSDAR be submitted to the NRC within two years following the permanent cessation of facility operations.

The 2014 DCE included the following three cost categories:

- **License Termination** -- Decommissioning SONGS 2&3 to the extent required to terminate the plant's operating license pursuant to 10 C.F.R. § 50.75(c);
- **Spent Fuel Management** -- Post-shutdown management of spent fuel until acceptance by the DOE pursuant to 10 C.F.R. § 50.54(bb) and ISFSI decommissioning pursuant to 10 C.F.R. § 72.30; and
- **Site Restoration** -- Demolition of uncontaminated structures and restoration of the site in accordance with the Navy Grant of Easement and the California State Lands Commission (CSLC) requirements.

The 2014 DCE was prepared using a WBS to differentiate between these three major cost categories. The 2014 DCE included SCE's actual costs incurred from June 7, 2013 through December 31, 2013 and estimated costs thereafter.

The 2014 DCE was based on the following technical approach to decommissioning:

- Prompt DECON decommissioning methodology;[13]
- Decommissioning would be performed by a DGC with oversight by the SONGS participants;
- Spent fuel would be transferred from the spent fuel pools and stored in Multi-Purpose Canisters at an on-site ISFSI; and[14]
- The DOE would begin accepting spent fuel from the nuclear industry in 2024 and complete the removal and acceptance of all spent fuel stored at SONGS by 2049. A dry transfer facility would not be necessary to transfer the spent nuclear fuel canisters to DOE transport canisters.

The 2014 DCE followed the approach originally presented in the Atomic Industrial Forum/National Environmental Studies Project Report AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates." The report was prepared in accordance with NRC Regulatory Guide 1.202, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors." The estimate was based on compliance with current regulatory requirements and proven decommissioning technologies.

On December 10, 2014, SCE filed Application (A.)14-12-007 and submitted the 2014 SONGS DCE to the CPUC. On April 21, 2016, the CPUC issued D.16-04-019, determining that the 2014 SONGS DCE was reasonable. On August 20, 2015, the NRC accepted the PSDAR, and found the DCE to be reasonable, stating:

> The NRC staff reviewed the cost estimates against the guidance in RG 1.185, Section C.3 and finds that SCE's site-specific DCE and the costs of long-term storage of spent fuel for SONGS, Units 2 and 3, are considered reasonable, are described consistent with the guidance in RG 1.185, provide sufficient details

[13] DECON is one of three basic methods for decommissioning defined by the NRC. Under the DECON method, the equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the Part 50 license after cessation of operations.

[14] The three options for long-term post-shutdown spent fuel management currently available to power plant operators are as follows: (1) wet storage consisting of continued maintenance and operation of the spent fuel pools; (2) dry storage consisting of transfer of spent fuel from the fuel pool to on-site dry storage modules after a cooling period; or (3) a combination of the two as is the present case at SONGS. Maintaining the spent fuel pool for an extended duration following cessation of operations would prevent the reduction of the Part 50 license and result in higher annual maintenance and operating costs than the dry storage alternative. Transfer of spent fuel to an ISFSI requires additional expenditures for purchase and construction of the ISFSI and dismantlement and disposal of the ISFSI following the completion of spent fuel transfer to the DOE.

associated with the funding mechanisms, and meet the requirements of 10 CFR 50.82(a)(4)(i).[15]

C. 2017 DCE Structure

The 2017 DCE utilizes the WBS that was established in the 2014 DCE,[16] and is estimated in 2017 dollars. Certain comparisons of the 2014 and 2017 DCEs are provided in 2014 dollars for ease of comparison. Costs were de-escalated from 2017 dollars to 2014 dollars using escalation factors provided by SCE.

Consistent with the 2014 DCE, the 2017 DCE provides the total costs to decommission SONGS 2&3. The liability for the total decommissioning costs is shared between the SONGS participants.[17]

As noted above, the 2014 DCE summarized the decommissioning costs by the License Termination, Spent Fuel Management, and Site Restoration cost categories (as generally defined by the NRC). The costs were further summarized into sequential periods within each cost category. For the 2017 DCE, Kenrich revised the periods from the 2014 DCE and established common periods that include all cost categories to better align the estimated costs with SCE's current project schedule and to simplify cost and schedule reporting.[18]

The 2017 DCE periods were designed to reflect the timing and completion of certain decommissioning milestones, including the completion of: (1) ISFSI fuel transfer operations; (2) mobilization and transition of various program activities (e.g. radiation protection program, maintenance, etc.) to SDS; and (3) major D&D phases of work defined in the DGC contract.[19] The completion of these milestones are expected to trigger certain reductions in staffing and undistributed costs. Figure 2 illustrates how the 2017 DCE periods align to the DGC contract and the completion of fuel transfer operations.

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[15] August 20, 2015 letter from NRC to SCE Vice President and Chief Nuclear Officer, Mr. Thomas J. Palmisano (ADAM Accession No.: ML15204A383)

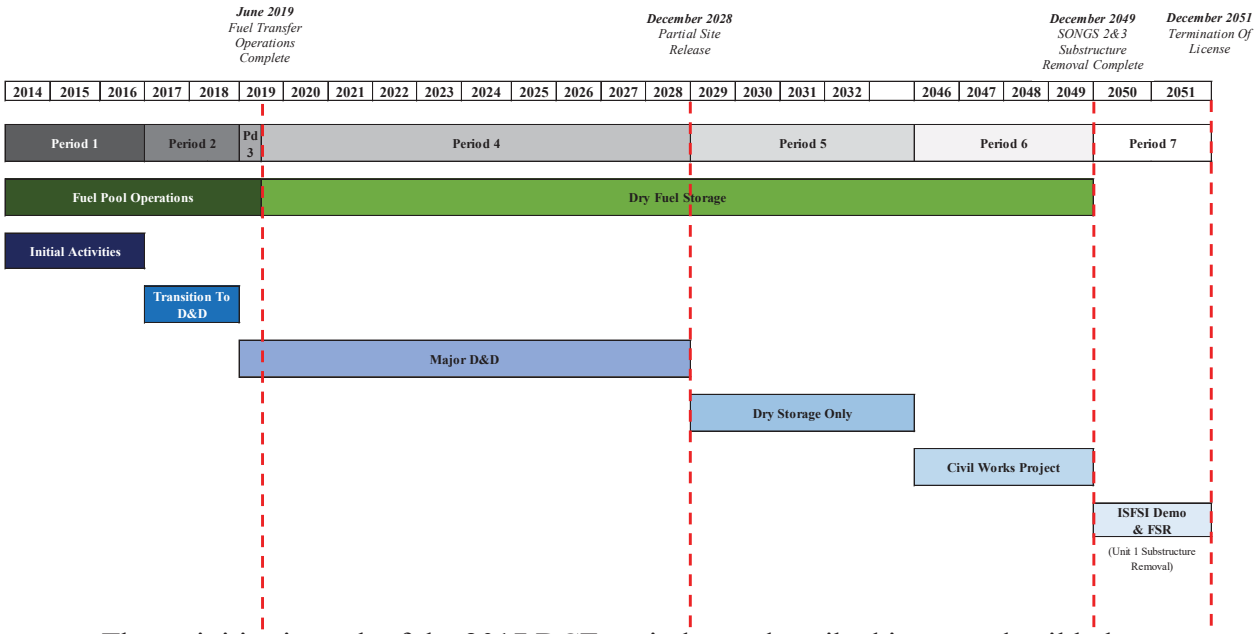
[16] The DCE line numbers in Appendix C of this report align to the line numbers in Appendix D of the 2014 DCE. The DCE line numbers in Appendix C of this report indicate the corresponding 2014 DCE: (1) NRC cost category, (2) 2014 DCE period, (3) cost type (i.e., distributed or undistributed), and (4) line number. For example, "LT-2-D-2.17" in Appendix C of this DCE corresponds to License Termination Period 2, distributed cost line number 2.17 in Appendix D of the 2014 DCE.

[17] The share of the liability for each of the SONGS Participants is provided in Appendix E.

[18] While new periods are used to summarize the costs in this DCE, the underlying cost structure remains the same as the 2014 DCE and will facilitate cost reconciliations between the two estimates.

[19] The phases of work in the DGC contract are described in more detail in Section V.D.3 below.

FIGURE 2 ALIGNMENT OF 2017 DCE PERIODS TO DECOMMISSIONING MILESTONES



The activities in each of the 2017 DCE periods are described in more detail below.

Period 1 – Initial Activities (June 2013 – December 2016)

Period 1 began on June 7, 2013 immediately following SCE's decision to permanently retire SONGS 2&3. As the decision was made approximately nine years before the units' Part 50 operating licenses would have expired, SONGS's premature retirement was unexpected. SCE spent the following six months reducing its workforce and beginning to formulate plans for decommissioning. This period includes preliminary decommissioning planning, obtaining necessary approvals of NRC license amendments, commencing the expansion of its on-site ISFSI facility, and procuring a DGC. The end of this period aligns with the selection and award of the DGC contract to SDS in December 2016.

Period 2 – Transition and Pool Storage (January 2017 – December 2018)

Period 2 began with the mobilization of SDS in January 2017 and extends through December 2018, during which time SCE will transition responsibility of D&D-related site management and support functions at SONGS to SDS. In addition, SCE will complete the CEQA process with CSLC and obtain a CDP from the CCC. The CEQA process and CDP are required for SDS to begin major decontamination and dismantlement work. Other activities during Period 2 include the ongoing expansion of the on-site ISFSI facilities, and various other smaller projects. In addition, SCE currently anticipates that Holtec will begin transferring spent fuel from the wet storage pools adjacent to the reactors into dry storage at the expanded on-site ISFSI in 2018. The fuel transfer operations will continue into Period 3.

Period 3 – D&D and Pool Storage (January 2019 – May 2019)

Period 3 begins with SDS's mobilization to commence the major physical work to decontaminate and dismantle SONGS 2&3. SDS's initial work during this period will primarily focus on the segmentation and packaging of reactor internals. The completion of the transfer of all fuel from the operating spent fuel pools into dry storage at the on-site ISFSI marks the end of Period 3. After the SONGS spent fuel pools are empty, related systems needed for the spent fuel pools will be retired, and otherwise applicable plant programs associated with spent fuel management will be modified, allowing SCE to further reduce SONGS staffing.

Period 4 – D&D and Dry Storage (June 2019 – December 2028)

Period 4 begins with the completion of fuel transfer operations and extends through the completion of the D&D work. Period 4 is expected to span approximately 9.6 years. This period includes the decontamination, dismantlement, demolition, removal, and waste disposal of the entire SONGS plant to approximately 3 feet below grade, with the exception of the on-site ISFSI and its associated security facilities, as well as the switchyard area. At the end of this period, SDS is expected to have completed all D&D work necessary to obtain NRC approval to reduce the Part 50 license site footprint to the ISFSI area only and to allow partial release of the SONGS site for unrestricted future use.

Period 5 – Dry Storage (January 2029 – December 2045)

During Period 5, the primary activity at SONGS will be the ongoing maintenance and security of the on-site ISFSI and the transfer of all SONGS spent fuel to the DOE. For purposes of the 2017 DCE, SCE has assumed that the DOE will begin performing its obligations nationally in 2028, which means that the DOE would begin removing the SONGS 2&3 spent nuclear fuel from the on-site ISFSI in 2034 under the pick-up rates published in the DOE's July 2004 "Acceptance Priority Ranking & Annual Capacity Report." In addition, Period 5 includes the Navy's National Environmental Policy Act (NEPA) environmental review process, associated with amending the SONGS real estate authorization to establish the site restoration or "end state" requirements for SONGS to return the property to the Navy. SCE will also initiate a Request For Proposal (RFP) process for substructure removal work.

Period 6 – Civil Works Project (January 2046 – December 2049)

Period 6 begins with a contractor mobilizing in order to perform the remaining work to restore the SONGS site for its return to the Navy. This work includes removing all onshore below-grade man-made structures, with the exception of the North Industrial Area where the on-site ISFSI is located. This work is currently expected to span approximately four years and is scheduled to be completed in December 2049. During Period 6, the DOE will continue to remove the remaining SONGS spent fuel from the ISFSI. SCE assumes all fuel is removed by the DOE by December 2049, marking the end of this period and the commencement of Period 7,

the demolition and removal of the ISFSI facilities and the final site restoration of the SONGS site.

Period 7 – ISFSI Demolition and Final Site Restoration (January 2050 – December 2051)

After all of the spent fuel is removed from SONGS, SCE can begin the final decommissioning and site restoration activities. These activities include dismantling and disposing of the ISFSI, completing the final site restoration work, obtaining NRC approval to terminate the remaining license covering the ISFSI, and returning the property to the Navy.[20] SCE projects that all decommissioning activities will be completed by 2051, approximately two years after the removal of the last spent fuel from the SONGS ISFSI.

In addition, for purposes of the 2017 DCE, SCE has assumed that the offshore intake and outfall conduits will be excavated and removed during this period.

At the end of decommissioning in 2051, all above and below ground man-made improvements, including the seawall and the offshore intake and outfall conduits, will be removed, and the site will be re-graded, re-vegetated, and returned to the Navy.

IV. Summary Of 2017 DCE Costs And Schedule

A. Summary Of 2017 DCE Recorded And Estimated Costs

SONGS has incurred $965.0 million (nominal dollars) through December 31, 2016 and estimates $3,737 million (2017 dollars) to complete decommissioning through 2051, for a total estimate of $4,702 million (Nominal/2017 dollars). The equivalent total in 2014 dollars is $4,479 million. Table 2 below summarizes the 2017 DCE by cost category.

[20] The Units 2&3 ISFSI Demolition and Final Site Restoration scope excludes the removal of the remaining Unit 1 foundations. The scope of the removal of the Unit 1 foundations is included in the Unit 1 DCE.

TABLE 2 SUMMARY OF 2017 DCE [21] [22]
($ IN THOUSANDS)

	Description	[A] Recorded Through 2016 (Nominal $)	[B] Estimate To Complete (2017$)	[C = A + B] Total Estimate At Completion (Nominal /2017$)	[D] Total Estimate At Completion (2014$)
1	**Distributed Projects**				
2	Completed Projects	$ 216,611	$ 1,234	$ 217,845	$ 214,024
3	ISFSI & Fuel Transfer Operations	140,047	142,385	282,432	270,210
4	Decontamination, Demolition, & Disposal	-	[redacted]	[redacted]	[redacted]
5	Other Projects	19,959	180,789	200,748	189,758
6	Substructure Removal	-	287,340	287,340	273,042
7	Offshore Conduit Removal	-	96,039	96,039	91,631
8	ISFSI Demolition	-	20,229	20,229	19,171
9	Final Site Restoration	-	7,267	7,267	6,905
10	**Distributed Subtotal**	[redacted]			
11					
12	**Undistributed Activities**				
13	Labor-Staffing	$ 336,628	$ 696,304	$ 1,032,932	$ 986,172
14	Non-Labor	241,104	639,572	880,676	848,786
15	Service Level Agreements	10,647	166,996	177,643	168,212
16	DGC Staffing	[redacted]			
17	**Undistributed Subtotal**				
18					
19	**Total**				

B. Summary Of 2017 DCE By Period

As discussed above, the 2017 DCE periods were designed to reflect the timing and completion of key decommissioning milestones that impact the cost estimate. The table below summarizes the 2017 DCE by period.

[redacted]

[22] The "estimate to complete" amounts in the tables through the report summarize period 2 through 7 costs (i.e., 2017 – 2051), which include January through September 2017 recorded costs.

TABLE 3 – SUMMARY OF 2017 DCE BY PERIOD (NOMINAL/2017$ IN THOUSANDS)

	Description	Period 1 Initial Activities (Nominal $)	Period 2 Transition and Pool Storage (2017$)	Period 3 D&D and Pool Storage (2017$)	Period 4 D&D and Dry Storage (2017$)	Period 5 Dry Storage (2017$)	Period 6 Civil Works Project (2017$)	Period 7 ISFSI Demolition & Final Site Restoration (2017$)	Total (Nominal/ 2017$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4									
5	**Distributed Projects**								
6	Completed Projects	$ 216,611	$ 1,234	$ -	$ -	$ -	$ -	$ -	$ 217,845
7	ISFSI & Fuel Transfer Operations	140,047	138,943	3,442	-	-	-	-	282,432
8	Decontamination, Demolition, & Disposal	[redacted]							
9	Other Projects	19,959	42,196	7,922	55,867	31,318	43,488	-	200,748
10	Substructure Removal	-	-	-	-	-	263,698	23,642	287,340
11	Offshore Conduit Removal	-	-	-	-	-	670	95,369	96,039
12	ISFSI Demolition	-	-	-	-	-	-	20,229	20,229
13	Final Site Restoration	-	-	-	-	-	-	7,267	7,267
14	**Distributed Subtotal**	[redacted]							
15									
16	**Undistributed Activities**								
17	Labor-Staffing	$ 336,628	$ 125,814	$ 22,954	$ 284,800	$ 172,804	$ 75,196	$ 14,735	$ 1,032,932
18	Non-Labor	241,104	84,020	17,913	220,608	218,376	72,388	26,266	880,676
19	Service Level Agreements	10,647	27,510	4,518	83,094	20,521	22,210	9,143	177,643
20	DGC Staffing	[redacted]							
21	**Undistributed Subtotal**								
22									
23	**Total**	[redacted]							**$ 4,702,264**

TABLE 4 – SUMMARY OF 2017 DCE BY PERIOD (2014$ IN THOUSANDS)

	Description	Period 1 Initial Activities (2014 $)	Period 2 Transition and Pool Storage (2014$)	Period 3 D&D and Pool Storage (2014$)	Period 4 D&D and Dry Storage (2014$)	Period 5 Dry Storage (2014$)	Period 6 Civil Works Project (2014$)	Period 7 ISFSI Demolition & Final Site Restoration (2014$)	Total (2014$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4									
5	**Distributed Projects**								
6	Completed Projects	$ 213,032	$ 992	$ -	$ -	$ -	$ -	$ -	$ 214,024
7	ISFSI & Fuel Transfer Operations	136,403	130,570	3,237	-	-	-	-	270,210
8	Decontamination, Demolition, & Disposal	[redacted]							
9	Other Projects	19,580	39,699	7,455	52,611	29,481	40,932	-	189,758
10	Substructure Removal	-	-	-	-	-	250,603	22,438	273,042
11	Offshore Conduit Removal	-	-	-	-	-	637	90,994	91,631
12	ISFSI Demolition	-	-	-	-	-	-	19,171	19,171
13	Final Site Restoration	-	-	-	-	-	-	6,905	6,905
14	**Distributed Subtotal**	[redacted]							
15									
16	**Undistributed Activities**								
17	Labor-Staffing	$ 332,184	$ 118,054	$ 21,564	$ 267,549	$ 162,337	$ 70,641	$ 13,843	$ 986,172
18	Non-Labor	239,691	79,724	17,005	210,259	208,221	68,862	25,023	848,786
19	Service Level Agreements	10,278	26,121	4,288	78,793	19,278	20,865	8,589	168,212
20	DGC Staffing	[redacted]							
21	**Undistributed Subtotal**								
22									
23	**Total**	[redacted]							**$ 4,478,566**

V. Bases Of Estimate And Key Assumptions

A. General Principles

Where available, Kenrich relied on executed contracts, actual cost data, and lessons learned from on-site performance to date. The cost estimate of decommissioning activities through the completion of the major decontamination, dismantlement, and waste disposal activities at SONGS in 2028 is based on competitively bid contracts and detailed project cost estimates prepared by SCE project managers. Kenrich worked with SCE personnel to ensure project cost estimates were reasonable and consistent with underlying key assumptions. Kenrich also worked with SCE to determine appropriate contingency factors to ensure that the total estimate remained reasonable and conservative. In addition, Kenrich incorporated project costs that were not included in the 2014 DCE, including those associated with the substantial environmental permitting efforts that are currently in process.

The majority of the cost estimates for activities after 2028, such as the substructures removal and the final site restoration are based on either the 2014 DCE values or updated estimates prepared by High Bridge Associates, experts in cost estimating.[23] Consistent with industry practice, the 2014 DCE used quantity take-offs from plant drawings and Unit Cost Factors.

Kenrich worked with knowledgeable SCE personnel to prepare cost estimates for the ongoing operations and maintenance of the SONGS facilities, as well as the oversight and support of the decommissioning project. Consistent with the 2014 DCE, these indirect project costs are referred to as undistributed costs in the 2017 DCE. Such undistributed costs include Utility Staffing, Contracted Services, Energy, Site Lease expenses, among other items. Kenrich worked closely with knowledgeable SCE personnel to develop detailed cost estimates that reflect the current known regulatory and project support requirements throughout the entire decommissioning project. Kenrich ensured these cost estimates were supported, reviewed by subject matter experts, and consistent with the project schedule and other key underlying assumptions.

B. Key Facts And Assumptions

Kenrich worked closely with SCE personnel to identify, define, and support the key assumptions underlying the 2017 DCE. As part of this process, subject matter experts were interviewed and meetings were held with cross-functional teams to review and refine the

[23] High Bridge Associates is a project management consulting and services company with experience supporting capital projects, decommissioning and closure projects, new build construction projects, and operating/maintenance programs in various markets. High Bridge has provided consulting and technical subject matter expert services to customers spanning Cost Estimating, Cost/Schedule Reviews, Risk Assessments, Due Diligence Evaluations, Feasibility Studies, Readiness Assessments, Contract Change Management/Claims, and Technical/Management Assessments.

assumptions. Additionally, relevant supporting documents were identified and reviewed to confirm accuracy and reasonableness.

The key assumptions and general bases of estimate for the 2017 DCE are summarized below. The detailed bases for the estimated costs for specific distributed and undistributed activities are described in subsequent sections of this report.

General

1. Costs are presented in the same WBS utilized in the 2014 DCE (see Appendix C). Distributed costs are summarized and discussed by major project, and undistributed costs are discussed by cost category.

2. Recorded costs for decommissioning activities through September 30, 2017 are included in this estimate.

3. Approximately $[redacted] billion of the SONGS decommissioning project are covered by two contracts (i.e., ISFSI expansion and fuel transfer operations with Holtec and the DGC contract with SDS). Those contract amounts are incorporated into this DCE.[24]

Decontamination, Dismantlement, Demolition, and Disposal to Achieve Partial Site Release

4. The DGC contract with SDS was executed in December 2016. SDS mobilized to the SONGS site and commenced Phase I work (transition and planning) on January 9, 2017.

5. The pricing of the SDS contract generally covers two phases of work: transition and planning (Phase I) and the decontamination, dismantlement, and removal of all man-made improvements to 3 feet below grade (and or deeper as required) to reduce the Part 50 license to the ISFSI area only (Phase II). In addition, SDS is expected to install backfill and perform other work as requested.

6. The CEQA review process completed by the CSLC will conclude with the issuance of an Environmental Impact Report that will be utilized by the CCC in connection with its issuance of a CDP in the last quarter of 2018. The CDP will allow physical decommissioning work to commence at SONGS. Accordingly, SDS is expected to begin Phase II work in January 2019.

7. SDS's Phase II work is estimated to be completed by December 2028, following the submission of Final Site Survey to the NRC and the approval of a partial site release, reducing the SONGS 2&3 NRC Part 50 license footprint to the ISFSI area only.[25]

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[24] Contract milestone payments are aligned with SCE's current expected project schedule.

[25] SDS's Phase II work also covers non-radiological hazardous waste disposal, e.g., asbestos, chromates, lead paint, and polychlorinated biphenyls (PCBs).

8. Following the D&D work, the SONGS plant site will be backfilled to current grade levels. Clean material available on the SONGS plant site may be acceptable for purposes of backfill and additional required backfill material will be imported from offsite.[26]

9. The 2017 DCE includes costs to purchase and import backfill material from offsite.

Spent Nuclear Fuel and GTCC Waste

10. All spent fuel will be transferred from the SONGS 2&3 pools to the on-site ISFSI by June 1, 2019.

11. Greater Than Class C (GTCC) waste will be stored in twelve canisters (five for reactor internals and one for spent fuel pool hardware/contents at each unit). GTCC waste from the containment buildings (e.g., portions of the reactor vessel internals) and spent fuel pools will be loaded into canisters and the loaded canisters will be transferred to the ISFSI.

12. The DOE will remove all GTCC waste from SONGS by 2049.

13. The DOE will commence accepting spent fuel from the commercial nuclear industry in 2028. The DOE will accept the first SONGS 2&3 spent fuel in 2034. All SONGS spent fuel will be removed from the ISFSI by 2049.

14. SCE is responsible for the loading of spent fuel and GTCC waste canisters into DOE transportation containers. (No dry transfer facility is required.)

15. GTCC disposal costs are conservatively estimated to account for potential DOE charges for acceptance of GTCC waste (i.e., in addition to the one-mill fee charged per kilowatt of generation per the Standard Contract with the DOE).

Substructure Removal Below 3 Feet Below Grade (i.e., Below 27 Feet Elevation)

16. SCE anticipates submitting an application to the Navy to amend the then current real estate authorization to seek a Navy determination of the substructure removal requirements. The Navy is expected to establish those requirements after completing a NEPA process and to include the requirements within a new or amended real estate authorization. This will define the final site release criteria for turnover of the SONGS property back to the Navy. The

[26] Paragraph 12 of the Grant of Easement, U.S. Department of Navy to Southern California Edison Company and San Diego Gas & Electric Company, dated May 12, 1964 states, "That upon termination of the easement granted herein, the Grantees at their expense may remove, and if desired by the government, shall remove any and all improvements installed or constructed hereunder and shall restore the Premises to a condition satisfactory to the Director, Southwest Division, Bureau of Yards and Docks, except that the Grantees shall not be obligated to restore any natural material cut or filled in the necessary excavation and grading of the Premises and such surrounding area within the Reservation as may have been contaminated by the operation of the Nuclear Station." Thus, the contract states that the Navy will specify the final site restoration requirements. The Navy has not yet specified its decontamination, backfill, compaction, grading, or re-vegetation requirements. The Navy is expected to establish these requirements as a part of the NEPA process and specify them within a new real estate authorization.

application is currently expected to be filed in 2040, with a Navy decision by 2045. That timing may change depending upon the time frame for the DOE removal of the spent fuel.

17. The removal of substructures (i.e., man-made improvements remaining after the D&D work and reduction of the Part 50 license to the ISFSI area only) is expected to begin in 2046 and be completed by December 2049. The final site restoration criteria will not be known until the Navy amends the SONGS site real estate authorization to include such criteria. Therefore, for purposes of the 2017 DCE, it is assumed that all SONGS 2&3 substructures will be removed during 2046-2049 (Period 6) (excluding the ISFSI which will be removed in a subsequent period).[27]

18. The estimated costs for the substructure removal work scope included in the 2014 DCE were reviewed and updated by High Bridge Associates. High Bridge Associates validated the quantities contained in the 2014 DCE and reduced the costs for non-radioactive waste disposal (based on La Paz, Arizona disposal rates, as compared to Oregon state rates which were assumed for purposes of the 2014 DCE).[28]

19. All concrete and other demolition debris (including "clean;" i.e., non-radioactive, non-hazardous material) that is deemed by the Navy or SCE to be not suitable for purposes of backfill will be transported to and disposed at an out-of-state Class III landfill at La Paz, Arizona or other facilities as may be required.[29] Cost for transporting clean scrap metal to a recycler is included in the DCE. No credit is taken for any salvage value of the scrap metal.

Conduits, ISFSI Demolition, and Final Site Restoration

20. For purposes of the 2017 DCE, it is assumed the offshore intake and outfall conduit will be removed during Period 7, ISFSI Demolition and Final Site Restoration, and will be complete by 2050.

[27] Any determination in the 2017 DCE that accounts for only partial removal of substructures would be non-conservative, arbitrary and inconsistent with the U.S. Navy easement, and without basis. If the final site restoration requirements specified in the future by the Navy allow less than complete removal of non-contaminated structures below 3 feet below grade (i.e., 27 feet elevation), then that new assumption will be incorporated into the subsequent DCE update.

[redacted]

[29] This out-of-state disposal requirement is consistent with the Governor of the State of California Executive Order D-62-02.

21. Following the complete removal of SONGS spent fuel and GTCC waste in 2049, the ISFSI and related facilities, and all remaining man-made structures (e.g., gunite walls, roads and parking lots, rail facilities) will be demolished and removed.

22. The SONGS site will be re-established to meet Navy site restoration requirements, including grading and re-vegetated.

Other

23. SCE expects to return the Mesa site to the Navy by July 31, 2021. The April 2011 lease from the Navy is known as the "Mesa lease" and contains five parcels. Parcels 5, 6, and 7 are associated with the Mesa site and are being returned. Parcels 8 & 9 are adjacent to the SONGS site and will be retained and incorporated into a new site lease during the real estate authorization process.

C. Project Schedule

The 2017 DCE assumes the timing for completing major activities is generally the same as the 2014 DCE, with the exception of the timing for removing the substructures below 3 feet below grade, which moved from 2031 to 2049. The schedule assumed in the 2017 DCE is as follows:

- **June 1, 2019** – Fuel Transfer Operations Complete.
- **December 2028** – Completion of the D&D work and receipt of NRC approval of the amendment to achieve partial site release and reduce the Part 50 License to the ISFSI area only.
- **December 2049** – Completion of Substructures removal below 3 feet below grade (i.e., 27 feet elevation).
- **December 2049** – All spent fuel removed from the site.
- **December 2051** – Completion of ISFSI Demolition, Conduits Removal, Final Site Restoration, and Lease Termination.

D. Distributed Costs

1. Completed Projects

Following the transition to decommissioning in June 2013, SCE began efforts to prepare the site for decommissioning and obtain necessary approvals of NRC license amendments. During the period from June 7, 2013 to September 30, 2017, SCE began and completed projects

to implement "Cold & Dark,"[30] perform the initial site assessment, dispose of legacy radwaste, prepare and receive approval for regulatory submittals, and select a DGC.

During this period, SCE also implemented projects that were needed to comply with regulatory requirements and other obligations. SCE began and completed projects related to Security Shutdown Strategy, Large Organism Exclusion Device Modifications, Fuel Cancellation payments, and other efforts.

Kenrich incorporated the recorded costs for the completed projects into the 2017 DCE. SCE will support the reasonableness of costs incurred in separate filings in the 2015 and 2018 NDCTP.

2. ISFSI And Fuel Transfer Operations

Following a competitive bidding process, SCE awarded a contract to Holtec to license, design, and construct an expanded on-site ISFSI; and to supply, load, and transfer the multi-purpose canisters containing fuel assemblies, from the SONGS 2&3 spent fuel pools to the expanded ISFSI. Holtec's work scope generally includes:

- Perform engineering, procurement, and construction services for a new on-site ISFSI pad and supporting facilities (e.g., security building, haul path).
- Perform fuel inspections and spent fuel pool waste characterizations.
- Provide spent fuel canisters and vertical ventilated underground dry storage modules to store SONGS spent fuel assemblies.
- Load and transport the canisters to the ISFSI and place the canisters into the dry storage modules.
- Transport the loaded GTCC waste (reactor internals and certain other non-fuel waste material) canisters to the ISFSI.[31]
- Engineering analyses, documentation, licensing and permitting activities.

SCE also maintains an ISFSI oversight team to ensure safe and efficient execution of the work by Holtec. The estimate for ISFSI and Fuel Transfer Operations also includes these SCE project oversight costs.

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[30] Includes plant modifications to systems that are not required to support spent fuel pool cooling or to meet other license conditions and places SONGS in a Cold and Dark condition in preparation of dismantlement and decontamination.

[31] The Holtec contract milestone payment for transferring the GTCC waste to the ISFSI, as well as costs associated with the procurement of GTCC canisters is included in a separate line item in the DCE for "GTCC Waste Storage" within "Other Projects."

TABLE 5 ISFSI & FUEL TRANSFER OPERATIONS ESTIMATE
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**ISFSI & Fuel Transfer Operations**				
2	ISFSI Expansion	$ 60,485	$ 74,100	$ 134,585	$ 128,026
3	Canister Fabrication	79,562	27,705	107,266	104,026
4	Spent Fuel Loading & Transfer to ISFSI	-	40,580	40,580	38,159
5	**ISFSI & Fuel Transfer Operations Total**	**$ 140,047**	**$ 142,385**	**$ 282,432**	**$ 270,210**

3. Decontamination, Dismantlement, Demolition, And Disposal

In December 2016, following a competitive bidding process, SCE executed a contract with SDS to perform the major decontamination, dismantlement, demolition, and disposal work at SONGS. The SDS work will include removing all SONGS 2&3 structures, systems, and components to 3 feet below grade (i.e., to 27 feet elevation) to permit the release of the property for unrestricted future use.[32] The SDS work will include characterizing, packaging, transporting, and disposing of waste from the SONGS site to appropriately licensed or permitted facilities.[33] Additionally, SDS will support SCE to modify or amend its NRC Part 50 license for SONGS 2&3, as well as its existing agreements with the U.S. Navy and other permitting agencies as required for completion of this work scope.

The work is divided into two phases:

Phase I: Transition and mobilization

Phase II: Decontamination, dismantlement, demolition, and waste disposal activities necessary to achieve partial site release and reduce the SONGS Part 50 license footprint to the ISFSI area only.

SDS will provide project management and field oversight, as well as planning and execution of D&D-related site management and support functions during the decommissioning of SONGS. SCE will perform oversight of SDS's activities, as required by the applicable licenses and permits, and will retain responsibility for license-related operations and security (i.e., spent fuel pool, fuel transfer, and ISFSI operations).

[32] SDS's work scope excludes the ISFSI and switchyard facilities.

[33] GTCC waste and spent fuel will be stored on the ISFSI and are not expected to be transported to a disposal facility during SDS's performance of the work.

Phase II D&D activities will include:

- Segmenting the SONGS 2&3 reactor vessels and internals, and loading them into storage containers.
- Removing and disposing of large components including SONGS 2&3 reactor pressure vessels, steam generators, pressurizers, and turbine-generators.
- Decontaminating and removing all structures, systems, and components as necessary to achieve partial site release and reduce the Part 50 license to the ISFSI area only.
- Removing certain above-seabed components of the ocean conduits.
- Necessary backfill work to achieve level grade for the power block area at an elevation of +30.0 feet.[34]
- Development of the partial site release plan in accordance with 10 C.F.R. § 20.1402 site release criteria. SDS will perform necessary D&D work to meet a radiological release criteria that does not exceed 15 millirem per year.[35]

The work scope under DGC contract does not include removing the intake/discharge structure beneath the seawall; ocean conduits; seawall and pedestrian walkway; gunite slope protection; and certain railroad track and site access roads.

Support for SCE-Retained Responsibilities

SCE will remain the licensed operator for NRC licenses associated with SONGS and will retain responsibility for interfacing and corresponding with the regulatory agencies in the management of licenses.[36] SCE will also continue to be the primary interface with the Navy (property owner), and the regulatory agencies and other government authorities responsible for existing permits and the issuance of new permits necessary to perform decommissioning. SDS will support SCE interface with the regulatory agencies and the Navy.[37]

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[34] Backfill material is excluded from the fixed price portion of SDS's contract scope.

[35] Per 10 C.F.R § 20.1402, the NRC site release criteria is 25 mrem per year calculated as the peak annual Total Effective Dose Equivalent ("TEDE") dose expected within the first 1,000 years after decommissioning. Release criteria is defined as residual radioactivity that is distinguishable from background radiation which results in a TEDE to an average member of the critical group, including that from groundwater sources of drinking water, and has been reduced to levels that are as low as reasonably achievable (ALARA).

[36] Nuclear operations are defined as operations and administration of installed, in-service structures, systems, and components within the Protected Area (PA).

[37] SCE will retain responsibility for personnel screening for access and badging to the SONGS protected areas (PAs) and vital areas (VAs) until all spent fuel is removed from the spent fuel pools and placed into storage on the ISFSI and the associated security plans are revised and approved. When the PAs/VAs are reduced to the ISFSI only, SCE will transition this responsibility to SDS for all areas except the ISFSI. SCE will retain responsibility for the

4. Substructure Removal

The substructure removal work will include the activities necessary to achieve the final "end state" requirements determined by the Navy (which are incremental to the NRC partial site release requirements that will be met during SDS's major D&D work). SCE currently plans to select a contractor to perform the substructure removal work in the mid-2040s.

For purposes of preparing the 2017 DCE, Kenrich retained High Bridge Associates to review and update the 2014 DCE estimate for the removal of substructures below 3 feet below grade.

More specifically, substructure removal activities will include the following:

- Removing substructure systems and components required to achieve "end state" requirements set forth in the applicable Navy real estate authorization for the SONGS Site. This work will include cleanup, remediation, and/or removal of structures, systems, and components, soils/debris, and/or contaminated groundwater, as required.[38]
- Backfilling excavations and voids with approved material and leveling the SONGS site, as required by regulatory and landowner closure requirements.
- Characterizing, packaging, transporting, processing, and disposing of SONGS waste as required to support the regulatory and landowner closure requirements.
- Removing the existing seawall and intake and outfall box culvert.

Excluded from the substructure removal work are the demolition and removal of the ISFSI after the spent nuclear fuel and GTCC waste is removed by the DOE. Also excluded is the other final site restoration work to meet requirements related to the final termination of the SONGS site easements (e.g., ocean conduits, gunite slopes, drainage requirements, access roads, etc.).

The estimated substructure removal costs are summarized in the table below.

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industrial and commercial security requirements at SONGS until the security plans are revised and the NRC approves the reduction of the PA/VAs to the area associated with the on-site ISFSI. SDS will take over this responsibility following the transfer of all spent fuel and GTCC to the ISFSI and the implementation of the associated revised security plans.

[38] The activities may also include removal of certain above grade facilities remaining after the major D&D work performed by SDS, potentially including non-essential utilities, parking areas, roads, and other improvements.

TABLE 6 SUBSTRUCTURE REMOVAL ESTIMATE
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**Substructure Removal**				
2	Excavation and Dewatering	$ -	$ 152,819	$ 152,819	$ 145,563
3	Demolition and Backfill	-	108,277	108,277	102,573
4	Other	-	8,833	8,833	8,386
5	Removal of Seawall and Box Culvert	-	17,410	17,410	16,520
6	**Substructure Removal**	**$ -**	**$ 287,340**	**$ 287,340**	**$ 273,042**

5. Offshore Conduit Removal

As was the case for the 2014 DCE, uncertainty remains regarding the requirements for removal of the offshore intake and outfall conduits located below the sea floor. For SONGS 1, the CSLC has allowed the SONGS 1 conduits to remain in place provided that the SONGS 1 Participants retain the liability to remove the SONGS 1 conduits should that be deemed by the CSLC to be necessary at a future date. For these reasons, the 2017 DCE continues to include an estimated cost to perform the full removal of the SONGS 2&3 offshore conduits as was estimated in the 2014 DCE. The 2017 DCE includes $96.0 million to fully remove the SONGS 2&3 offshore conduits.

6. ISFSI Demolition

Following the removal of all spent fuel and GTCC waste by the DOE, SCE will demolish and remove the ISFSI and perform activities necessary for the final restoration of the SONGS site. At the time the 2014 DCE was prepared, the specific plans to expand the ISFSI had not been defined. Later in 2014, SCE entered into a contract with Holtec to expand the ISFSI. Kenrich retained High Bridge Associates to update the ISFSI demolition estimate in the 2014 DCE to reflect the Holtec ISFSI pad. The updated estimate for ISFSI demolition is $20.2 million.

7. Final Site Restoration

The final restoration work includes the removal of the gunite slope protection; remaining railroad tracks, rails, and ballast; access roads and parking lots. In addition, this work includes any other work required by the Navy real estate authorization, which is expected to include the final grading and re-vegetation of the SONGS site. The total estimated final site restoration work in the 2017 DCE is $7.3 million. The 2014 DCE included, as part of final site restoration, the costs to remove the intake and outfall structure underneath the seawall, which required installing and removing dewatering equipment and a temporary seawall. The intake and outfall structure beneath the seawall, as well as the seawall itself, are now expected to be removed

during the civil works project (i.e., Period 6, 2046-2049). Therefore, the second dewatering process and temporary seawall are no longer necessary during final site restoration.

8. Other Distributed Projects

In addition to the major decommissioning projects discussed above, SCE must also perform other projects to comply with federal and state regulations and the terms of SCE's real estate authorizations with the Navy. These other projects and their associated estimated costs are shown in Table 7 and discussed in more detail below.

TABLE 7 OTHER DISTRIBUTED PROJECTS ESTIMATE
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**Other Projects**				
2	ISFSI Aging Management	$ 385	$ 38,376	$ 38,761	$ 36,489
3	Coastal Development Permit Extensions	-	5,580	5,580	5,252
4	GTCC Waste Storage	-	28,270	28,270	26,632
5	Mesa Site Turnover	7,245	13,967	21,212	20,341
6	CEQA Permitting	3,169	5,162	8,331	7,914
7	Initial Real Estate Authorization Renewal And Plant Easements	646	14,658	15,305	14,427
8	Plant Lease Extension	-	4,118	4,118	3,878
9	Plant Lease Amendment For Final Site Restoration	-	9,290	9,290	8,745
10	Cyber Security Modifications	8,513	1,131	9,644	9,380
11	DCE Update	-	3,897	3,897	3,669
12	GTCC Disposal	-	43,200	43,200	40,662
13	ISFSI CDP Settlement	-	4,543	4,543	4,277
14	Substructure Removal Contractor Procurement	-	7,447	7,447	7,011
15	NIA Sump Modifications	-	1,150	1,150	1,081
16	**Other Projects Total**	**$ 19,959**	**$ 180,789**	**$ 200,748**	**$ 189,758**

a. ISFSI Aging Management

The "Aging Management" project was established to develop inspection and maintenance programs for the Areva and Holtec spent fuel dry storage systems. Also included are initial cask testing, inspection equipment and licensing costs for dry cask NRC Certificate of Compliance (CoC) renewals, and Safety Analysis Report (SAR) updates. Ongoing required annual maintenance and inspections of the spent fuel dry storage systems are included in the undistributed non-labor Aging Management category.

b. Coastal Development Permit Extensions

SCE holds a Coastal Development Permit for the storage of SONGS 2&3 spent fuel in the Areva ISFSI system until November 2022, and a separate CDP to store SONGS 2&3 spent fuel in the Holtec ISFSI system until 2035. Therefore, SCE will need to obtain CDP extensions

from the CCC for the Areva and Holtec ISFSI systems prior to the expiration of the permits in 2022 and 2035, respectively.

c. GTCC Waste Storage

As part of the DGC contract, SDS is responsible for preparing, characterizing, and packaging the GTCC waste into canisters, with the exception of the relatively small amount of GTCC waste which currently resides in the spent fuel pools and will be loaded by Holtec. Holtec will supply the GTCC canisters and is also responsible for transferring the loaded GTCC waste canisters to the ISFSI pad. The estimated costs cover the purchase and licensing of GTCC canisters, as well as their transfer from the containment buildings to the ISFSI pad.

d. Mesa Site Turnover

SCE's Mesa site consists of five parcels leased from the Navy. Parcel 5 is on the west side of U.S. Interstate Highway 5 (I-5) and includes a security station to control access to Parcels 6 and 7. Parcels 6 and 7 are located on the east side of I-5 and comprise the largest portion of the Mesa site. Parcels 8 and 9 include a parking lot and lay-down area on the west side of I-5.

SCE currently estimates that Parcels 5, 6, and 7 will be returned to the Navy in 2021, and Parcels 8 & 9 will be retained until the end of decommissioning. As part of the process to return the parcels to the Navy, SCE must first remediate any contamination and obtain "No Further Action Letters" from the California Department of Toxic Substances Control (DTSC) indicating the property is available for unrestricted use.[39] The estimated cost associated with the project is based on currently anticipated remediation requirements.

e. CEQA Permitting (California State Lands Commission)

Under CEQA, the CSLC, as lead agency, is required to evaluate the SONGS decommissioning project and prepare an Environmental Impact Report (EIR) in response to SCE's application to modify and extend the existing CSLC lease regarding the offshore conduits. The CEQA permitting process began in 2015. The CSLC is expected to issue a draft EIR in the second quarter of 2018 and issue its Final EIR in the third quarter of 2018. The California Coastal Commission is then expected to review an application for a CDP based on the EIR, as well as its own additional analysis. The CCC is expected to approve the CDP in the fourth quarter of 2018. Following the receipt of the CDP, the physical decommissioning of the plant can proceed.

[39] On April 24, 2017, the DTSC issued a No Further Action Letter for Parcel 5. The efforts to assess and remediate contamination for Parcels 6 and 7 are ongoing. SCE continues to hold Parcel 5 as it provides access to Parcels 6 and 7.

f. Real Estate Authorization Renewals and Plant Lease Amendments

The current SONGS Plant Easement with the Navy expires in 2024. SCE will therefore seek an extension (new real estate authorization) covering the time to complete major decommissioning activities. As a federal agency, the Navy must undertake a NEPA environmental review prior to issuing a new real estate authorization. The initial NEPA process is expected to be completed in 2024 and will allow SCE to continue using the property until 2035.

In 2030, SCE will begin the process to further extend the lease from 2035 until such time the property is projected to be to be turned over to the Navy. In 2040, the Navy is expected to undertake another NEPA review to determine the final site restoration conditions, including the substructure removal requirements. These end-state requirements should be determined by 2045, prior to beginning the civil works project in 2046.

g. Cyber Security Modifications

NRC regulations require a Cyber Security Plan at SONGS to ensure certain digital assets, such as computer and communication systems and networks, are secure and protected. SCE has implemented 7 of 8 Cyber Security Plan milestones. At the end of 2017 the NRC granted approval for a license amendment to remove the cyber security license condition, thus waiving the requirement to implement Milestone 8.

h. DCE Update

As part of the NDCTP, SCE is required to submit an updated DCE for approval by the CPUC.

i. GTCC Disposal

Presently, a disposal facility licensed to accept GTCC waste does not exist in the United States. Courts have determined that the DOE is obligated to accept and dispose of GTCC waste; however, issues regarding costs remain unsettled. For purposes of the 2017 DCE, the cost of shipping and disposing of a GTCC canister was assumed to equal the cost associated with a canister of SONGS spent fuel. The one-mill fee per kilowatt-hour of generation under the Standard Contract was used to estimate this cost.

j. ISFSI CDP Settlement

In August 2017, SCE reached a settlement agreement with parties opposed to the storage of spent fuel at SONGS. As part of that settlement, SCE agreed to incur up to $4 million on commercially reasonable efforts to identify an alternative location for SONGS spent fuel storage.

SCE also incurred third-party legal costs to reach the settlement. Given the ongoing analysis and current uncertainty relating to the potential location and requirements of an acceptable alternative spent fuel storage site, the associated costs with moving to an alternative site have not been included in this DCE.

k. Substructure Removal Contractor Procurement

In 2044, SCE will begin efforts to procure a contractor for the removal of SONGS substructures and placement of permanent backfill. The 2017 DCE therefore includes costs to cover a competitive bidding process, including the development of a Request for Proposal, proposal evaluation, and contract award. For purposes of this DCE, the effort was assumed to be approximately one-half the expended cost to procure a DGC for the major D&D work.

l. NIA Sump Modifications

The NIA sump currently discharges to the SONGS 2&3 dilution water system. The dilution water system will be retired by SDS, and therefore the discharge pathway for the NIA sump will need to be modified. Kenrich utilized the current budget estimate provided by the cognizant SCE Project Manager.

E. Undistributed Costs

Undistributed costs represent activities or fees, necessary to oversee, manage and support the overall decommissioning project. Undistributed costs are sometimes referred to as collateral, indirect, or "level of effort" costs. By their nature, such costs are not assignable to specific activities representing the physical work performed to decommission a nuclear plant.

Undistributed activities and cost items are characterized by a uniform rate of activity over a specific period of time. Accordingly, undistributed costs were estimated for each decommissioning period. Within each period, the undistributed costs are incurred at a fixed rate and are thus largely time-dependent.

The table below summarizes the undistributed costs incurred through 2016 and future costs estimated for each decommissioning period. The costs are also segregated between labor and non-labor. The labor items include staff to provide oversight, management and other support. Non-labor items include costs associated with services performed by third-parties, as well as rents, fees, and other costs necessary to ensure compliance with regulatory and other requirements.

San Onofre Nuclear Generating Station Units 2&3
2017 Decommissioning Cost Estimate

TABLE 8 UNDISTRIBUTED COST ESTIMATE (NOMINAL/2017$ IN THOUSANDS)

	Description	Period 1 Initial Activities (Nominal $)	Period 2 Transition and Pool Storage (2017$)	Period 3 D&D and Pool Storage (2017$)	Period 4 D&D and Dry Storage (2017$)	Period 5 Dry Storage (2017$)	Period 6 Civil Works Project (2017$)	Period 7 ISFSI Demolition & Final Site Restoration (2017$)	Total (Nominal/ 2017$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4	**Undistributed Activities**								
5	**Labor-Staffing**								
6	Site Management & Administration		$ 19,393	$ 3,379	$ 71,195	$ 16,666	$ 13,265	$ 1,901	
7	Plant Management		46,774	8,140	46,085	85,274	20,799	2,340	
8	Decommissioning Oversight		14,417	4,916	136,266	13,417	27,121	8,919	
9	**Utility Staff Subtotal**	**$ 245,555**	**$ 80,583**	**$ 16,436**	**$ 253,546**	**$ 115,356**	**$ 61,185**	**$ 13,159**	**$ 785,820**
10	Security Force	91,073	45,231	6,518	31,254	57,448	14,012	1,576	247,112
11	**Labor-Staffing Subtotal**	**$ 336,628**	**$ 125,814**	**$ 22,954**	**$ 284,800**	**$ 172,804**	**$ 75,196**	**$ 14,735**	**$ 1,032,932**
12									
13	**Non-Labor**								
14	Aging Management	$ -	$ -	$ 48	$ 4,209	$ 10,018	$ 1,955	$ -	$ 16,230
15	Association Fees and Expenses	817	1,332	251	3,910	1,958	478	215	8,961
16	Community Engagement Panel	2,304	1,640	279	5,482	2,405	566	283	12,958
17	Contracted Services	67,641	33,556	3,957	59,073	50,430	16,086	4,349	235,092
18	DAW Disposal	-	32	-	-	-	-	-	32
19	Decommissioning Advisor	2,515	1,231	278	6,392	-	-	-	10,416
20	DGC Executive Oversight Committee	-	508	144	3,306	-	-	-	3,958
21	Emergency Preparedness Fees	9,099	3,792	864	15,081	16,998	4,146	-	49,980
22	Energy	16,964	7,571	2,241	45,194	10,983	4,117	526	87,596
23	Environmental Permits and Fees	3,081	662	14	328	1,064	1,154	576	6,879
24	Ground Water Monitoring	-	-	-	-	391	92	46	529
25	Information Technology	12,886	5,248	479	7,494	2,486	3,033	1,365	32,991
26	Insurance	13,824	4,778	977	15,947	22,029	5,688	2,479	65,722
27	Third Party Legal	4,336	2,579	479	7,571	7,648	2,300	230	25,142
28	NRC Fees	4,566	2,836	248	9,169	10,369	2,455	2,646	32,291
29	Office Space	-	-	-	1,173	391	92	92	1,748
30	Security Related Expenses	1,552	1,209	422	1,017	5,461	2,192	526	12,378
31	Severance	89,594	9,135	6,001	9,782	2,367	-	6,165	123,044
32	Site Lease and Easement Expenses	8,049	5,710	1,039	21,040	47,825	11,552	5,930	101,145
33	Loading Spent Fuel & GTCC Waste To DOE	-	-	-	-	17,940	14,628	-	32,568
34	Tools and Equipment	49	-	-	-	-	-	-	49
35	Water	1,663	1,224	184	4,243	7,261	1,771	797	17,143
36	Utility Staff Health Physics Supplies	2,163	979	9	198	352	83	41	3,825
37	**Non-Labor Subtotal**	**$ 241,104**	**$ 84,020**	**$ 17,913**	**$ 220,608**	**$ 218,376**	**$ 72,388**	**$ 26,266**	**$ 880,676**
38									
39	Service Level Agreements	10,647	27,510	4,518	83,094	20,521	22,210	9,143	177,643
40	DGC Staffing	[redacted]							
41	**Undistributed Activities Subtotal**	[redacted]							
42		[redacted]							
43	**Distributed Projects**	[redacted]							
44		[redacted]							
45	**Total**	[redacted]							**$ 4,702,264**

TABLE 9 UNDISTRIBUTED COST ESTIMATE (2014$ IN THOUSANDS)

	Description	Period 1 Initial Activities (2014$)	Period 2 Transition and Pool Storage (2014$)	Period 3 D&D and Pool Storage (2014$)	Period 4 D&D and Dry Storage (2014$)	Period 5 Dry Storage (2014$)	Period 6 Civil Works Project (2014$)	Period 7 ISFSI Demolition & Final Site Restoration (2014$)	Total (2014$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4	**Undistributed Activities**								
5	**Labor-Staffing**								
6	Site Management & Administration		$ 18,179	$ 3,175	$ 66,883	$ 15,656	$ 12,462	$ 1,785	
7	Plant Management		43,882	7,647	43,293	80,109	19,539	2,198	
8	Decommissioning Oversight		13,537	4,618	128,012	12,604	25,478	8,378	
9	**Utility Staff Subtotal**	**$ 242,544**	**$ 75,598**	**$ 15,440**	**$ 238,189**	**$ 108,369**	**$ 57,478**	**$ 12,362**	**$ 749,981**
10	Security Force	89,640	42,456	6,123	29,360	53,968	13,163	1,481	236,192
11	**Labor-Staffing Subtotal**	**$ 332,184**	**$ 118,054**	**$ 21,564**	**$ 267,549**	**$ 162,337**	**$ 70,641**	**$ 13,843**	**$ 986,172**
12									
13	**Non-Labor**								
14	Aging Management	$ -	$ -	$ 45	$ 3,958	$ 9,421	$ 1,838	$ -	$ 15,262
15	Association Fees and Expenses	800	1,277	237	3,701	1,882	459	207	8,564
16	Community Engagement Panel	2,267	1,556	267	5,268	2,311	544	272	12,486
17	Contracted Services	66,942	31,650	3,736	55,800	47,718	15,215	4,102	225,164
18	DAW Disposal	-	30	-	-	-	-	-	30
19	Decommissioning Advisor	2,470	1,156	261	6,011	-	-	-	9,899
20	DGC Executive Oversight Committee	-	477	135	3,109	-	-	-	3,722
21	Emergency Preparedness Fees	9,047	3,645	830	14,496	16,339	3,985	-	48,341
22	Energy	16,840	7,277	2,154	43,440	10,557	3,957	506	84,732
23	Environmental Permits and Fees	3,065	636	14	312	1,007	1,108	553	6,695
24	Ground Water Monitoring	-	-	-	-	368	87	43	497
25	Information Technology	12,845	4,945	454	7,117	2,361	2,881	1,296	31,900
26	Insurance	13,779	4,592	939	15,328	21,175	5,467	2,383	63,663
27	Third Party Legal	4,234	2,425	451	7,119	7,192	2,163	216	23,799
28	NRC Fees	4,539	2,725	239	8,813	9,967	2,360	2,544	31,187
29	Office Space	-	-	-	1,104	376	88	87	1,655
30	Security Related Expenses	1,536	1,150	403	973	5,166	2,069	496	11,792
31	Severance	89,524	8,599	5,657	9,222	2,232	-	5,812	121,047
32	Site Lease and Easement Expenses	7,996	5,488	999	20,223	45,970	11,104	5,700	97,481
33	Loading Spent Fuel & GTCC Waste To DOE	-	-	-	-	16,870	13,756	-	30,626
34	Tools and Equipment	49	-	-	-	-	-	-	49
35	Water	1,654	1,176	177	4,078	6,979	1,702	766	16,534
36	Utility Staff Health Physics Supplies	2,103	918	8	187	331	78	39	3,663
37	**Non-Labor Subtotal**	**$ 239,691**	**$ 79,724**	**$ 17,005**	**$ 210,259**	**$ 208,221**	**$ 68,862**	**$ 25,023**	**$ 848,786**
38									
39	Service Level Agreements	10,278	26,121	4,288	78,793	19,278	20,865	8,589	168,212
40	DGC Staffing								
41	**Undistributed Activities Subtotal**								
42									
43	**Distributed Projects**								
44									
45	**Total**								**$ 4,478,566**

1. Decommissioning Staffing

Since January 2017, SCE and SDS have been working closely to manage and implement the transition of numerous management programs and functions from SCE to SDS. Following this transition, SCE will maintain an oversight role with respect to SDS's contract. SCE will continue to be responsible for the ISFSI project, for ongoing nuclear operations, security, and other distributed projects (e.g., ISFSI Aging Management, Mesa Turnover). Following the completion of the SDS D&D contract, SCE will take back over the performance of the on-site programs and functions that had been transitioned to SDS.

With contracts now in place for the majority of the SONGS decommissioning work, SCE was able to carefully evaluate its own staffing needs. As part of the process to develop the staffing projections, each SONGS division was grouped into the following categories.

Site Management & Administration – Responsible for oversight and strategic planning, ensuring compliance with regulatory and permitting requirements, safety, security, and overall project cost and schedule.

Plant Management – Responsible for the operations, maintenance, and security of the plant facilities. Staffing levels are expected to decrease significantly after the nuclear fuel is transferred from the spent fuel pool to the ISFSI pad.

Project Oversight – Responsible for oversight of the SDS D&D contract, management of the ISFSI, and other distributed projects. The oversight role ensures all work is completed safely and in compliance with the contract, government regulations, and permits. The staffing levels will vary over the duration of the project based on the amount of physical work being performed (e.g., the number of radiological oversight personnel will decrease after D&D is complete).

As part of the process to estimate staffing needs, senior management met with SONGS division managers to identify major activities during each phase of the decommissioning project. The estimated staffing for each period was based on a "bottom up" assessment of each needed discipline and position. Kenrich also worked with SCE management to vet the underlying assumptions and confirm the rationale underlying the projections. This effort involved numerous interviews of SONGS division managers, an analysis of the plan to transition management and supervision responsibilities from SCE to SDS, and a reconciliation to the staffing levels in the 2014 DCE.[40]

Staffing levels at other utilities having nuclear decommissioning experience were reviewed and considered, while also taking into account site-specific requirements and characteristics of SONGS. To further ensure the reasonableness of the SONGS staffing projections, SCE retained ABZ, an industry expert in decommissioning cost estimating. SCE specifically requested ABZ to provide input based on their experiences working with other nuclear utilities and to confirm that the SONGS projections were in line with industry norms.

The table below summarizes the staffing projection by period. The average staffing levels estimated for each period are intended to account for anticipated adjustments within each decommissioning period.

[40] The 2014 DCE did not assume the transition of programs to the DGC, therefore the headcount for certain divisions, such as maintenance and radiological control and chemistry, decreased in the 2017 DCE, but the decommissioning oversight positions increased in the 2017 DCE.

TABLE 10 UTILITY & SECURITY FORCE AVERAGE STAFFING BY PERIOD[41]

	Description	Period 2 Transition and Pool Storage	Period 3 D&D and Pool Storage	Period 4 D&D and Dry Storage	Period 5 Dry Storage	Period 6 Civil Works Project	Period 7 ISFSI Demolition & Final Site Restoration
1	Start	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050
2	End	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051
3	Duration (Years)	2 0	0 4	9 6	17 0	4 0	2 0
4							
5	**Site Management & Administration**						
6	Site Management & Administration	16	11	10	1	3	-
7	Decommissioning Finance	5	8	8	1	4	1
8	Regulatory Affairs & Nuclear Oversight	10	8	8	2	4	4
9	**Total Site Management & Administration**	**30**	**27**	**26**	**4**	**11**	**5**
10							
11	**Plant Management**						
12	Plant Management	1	1	1	1	1	-
13	Operations	40	36	-	-	-	-
14	Radiological Control & Chemistry	13	-	-	-	-	-
15	Maintenance, Work Control, & PI/CAP	18	7	7	7	7	3
16	Engineering	15	7	7	7	7	3
17	EP Planning	3	3	2	2	2	1
18	Security	155	158	34	34	34	14
19	**Total Plant Management**	**244**	**212**	**51**	**51**	**51**	**20**
20							
21	**Decommissioning Oversight**	**23**	**38**	**45**	**-**	**22**	**16**
22							
23	**Total**	**296**	**277**	**122**	**55**	**84**	**41**

The costs associated with the projected staffing is based on average labor rates for each position. The staffing cost estimate includes labor burdens and short-term incentive compensation, and accounts for positions being filled by contractors.

The table below summarizes the labor-staffing costs by each project period.

[41] Excludes DGC staffing and third-party contractors at SONGS.

TABLE 11 UNDISTRIBUTED LABOR COST ESTIMATE (NOMINAL/2017$ IN THOUSANDS)

	Description	Period 1 Initial Activities (Nominal)	Period 2 Transition and Pool Storage (2017$)	Period 3 D&D and Pool Storage (2017$)	Period 4 D&D and Dry Storage (2017$)	Period 5 Dry Storage (2017$)	Period 6 Civil Works Project (2017$)	Period 7 ISFSI Demolition & Final Site Restoration (2017$)	Total (Nominal/ 2017$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4	**Utility Staff**								
5	Site Management & Administration		$ 19,393	$ 3,379	$ 71,195	$ 16,666	$ 13,265	$ 1,901	
6	Plant Management		46,774	8,140	46,085	85,274	20,799	2,340	
7	Decommissioning Oversight		14,417	4,916	136,266	13,417	27,121	8,919	
8	**Utility Staff Subtotal**	**$ 245,555**	**$ 80,583**	**$ 16,436**	**$ 253,546**	**$ 115,356**	**$ 61,185**	**$ 13,159**	**$ 785,820**
9	Security Force	91,073	45,231	6,518	31,254	57,448	14,012	1,576	247,112
10	**Labor-Staffing Total**	**$ 336,628**	**$ 125,814**	**$ 22,954**	**$ 284,800**	**$ 172,804**	**$ 75,196**	**$ 14,735**	**$ 1,032,932**

TABLE 12 UNDISTRIBUTED LABOR COST ESTIMATE (2014$ IN THOUSANDS)

	Description	Period 1 Initial Activities (2014$)	Period 2 Transition and Pool Storage (2014$)	Period 3 D&D and Pool Storage (2014$)	Period 4 D&D and Dry Storage (2014$)	Period 5 Dry Storage (2014$)	Period 6 Civil Works Project (2014$)	Period 7 ISFSI Demolition & Final Site Restoration (2014$)	Total (2014$)
1	Start	6/7/2013	1/1/2017	1/1/2019	6/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2016	12/31/2018	5/31/2019	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	3 6	2 0	0 4	9 6	17 0	4 0	2 0	
4	**Utility Staff**								
5	Site Management & Administration		$ 18,179	$ 3,175	$ 66,883	$ 15,656	$ 12,462	$ 1,785	
6	Plant Management		43,882	7,647	43,293	80,109	19,539	2,198	
7	Decommissioning Oversight		13,537	4,618	128,012	12,604	25,478	8,378	
8	**Utility Staff Subtotal**	**$ 242,544**	**$ 75,598**	**$ 15,440**	**$ 238,189**	**$ 108,369**	**$ 57,478**	**$ 12,362**	**$ 749,981**
9	Security Force	89,640	42,456	6,123	29,360	53,968	13,163	1,481	236,192
10	**Labor-Staffing Total**	**$ 332,184**	**$ 118,054**	**$ 21,564**	**$ 267,549**	**$ 162,337**	**$ 70,641**	**$ 13,843**	**$ 986,172**

2. Undistributed Non-Labor Costs

In addition to staffing, SCE incurs non-labor costs to support the decommissioning efforts. As part of the process to identify and estimate future non-labor costs, historical recorded costs were reviewed in detail. Kenrich worked with knowledgeable SONGS personnel to develop and estimate future decommissioning costs which are summarized in Table 13 and broken down below.

TABLE 13 UNDISTRIBUTED NON-LABOR COST ESTIMATE
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**Non-Labor**				
2	Aging Management	$ -	$ 16,230	$ 16,230	$ 15,262
3	Association Fees and Expenses	817	8,144	8,961	8,564
4	Community Engagement Panel	2,304	10,653	12,958	12,486
5	Contracted Services	67,641	167,451	235,092	225,164
6	DAW Disposal	-	32	32	30
7	Decommissioning Advisor	2,515	7,901	10,416	9,899
8	DGC Executive Oversight Committee	-	3,958	3,958	3,722
9	Emergency Preparedness Fees	9,099	40,881	49,980	48,341
10	Energy	16,964	70,631	87,596	84,732
11	Environmental Permits and Fees	3,081	3,798	6,879	6,695
12	Ground Water Monitoring	-	529	529	497
13	Information Technology	12,886	20,105	32,991	31,900
14	Insurance	13,824	51,898	65,722	63,663
15	Third Party Legal	4,336	20,807	25,142	23,799
16	NRC Fees	4,566	27,724	32,291	31,187
17	Office Space	-	1,748	1,748	1,655
18	Security Related Expenses	1,552	10,826	12,378	11,792
19	Severance	89,594	33,450	123,044	121,047
20	Site Lease and Easement Expenses	8,049	93,096	101,145	97,481
21	Tools and Equipment	49	-	49	49
22	Water	1,663	15,480	17,143	16,534
23	Utility Staff Health Physics Supplies	2,163	1,662	3,825	3,663
24	Loading Spent Fuel & GTCC Waste To DOE	-	32,568	32,568	30,626
25	**Non-Labor Total**	**$ 241,104**	**$ 639,572**	**$ 880,676**	**$ 848,786**

a. Aging Management

Aging Management programs cover both the Areva and Holtec dry storage systems. In addition to the scope covered by the distributed Aging Management project, the programs include annual facility maintenance and inspection as well as in-service canister inspections every five years, in compliance with the respective Areva and Holtec SARs.

The Areva Aging Management undistributed costs begin in 2022, after the NRC Certificate of Compliance is renewed. These costs continue until the DOE is assumed to accept the final Areva canister from SONGS in 2037. The Holtec Aging Management costs begin in 2019 after all of the fuel has been transferred from the SONGS 2&3 spent pools to the ISFSI, and then continue until the DOE is assumed to accept the final Holtec canister in 2049.

b. Association Fees and Other Expenses

Association Fees and Other Expenses include Nuclear Energy Institute (NEI) membership fees, costs related to an external Nuclear Oversight Board (NOB), and an outside

advisor to SCE's Internal Nuclear Management Group (INMG). SCE remains an NEI member to obtain access to industry policies, standards, and guidance regarding decommissioning. The NOB is composed of independent review specialists who provide independent review of decommissioning activities.

NEI Fees are estimated to be incurred through Period 7 (ISFSI Demolition & Final Site Restoration); NOB costs are expected through Period 4 (major D&D); and SCE anticipates retaining an outside advisor to the INMG until 2022.

c. Community Engagement Panel

The SONGS Community Engagement Panel (CEP) holds periodic meetings with the public to provide information on various issues, including decommissioning plans, spent fuel management, emergency planning, security, and the environmental review process. CEP costs are estimated to be incurred through the end of Period 7 (ISFSI Demolition & Final Site Restoration). The annual estimate is based on the 2018 budgeted amounts per CEP meeting, and is adjusted proportionately based on the number of meetings estimated each year. Six CEP meetings are assumed in 2018, four CEP meetings per year are estimated during major D&D, through 2028, and one meeting per year is assumed after major D&D is complete.

d. Contracted Services

Contracted Services generally consist of shorter-term supplemental resources, specialty contractors and consultants, third-party services, materials, equipment, and supplies. SONGS senior management, division managers, and Kenrich worked together to identify and estimate the projected costs. Contracted Services costs were estimated for each decommissioning period in each of the following divisions: (1) Decommissioning Projects / Decommissioning Oversight; (2) Engineering; (3) Emergency Preparedness; (4) Maintenance; (5) Nuclear Oversight, Safety, Regulatory Affairs; (6) Operations; (7) Decommissioning Finance; and (8) Site Management & Administration.

Similar to the undistributed staffing, the projected needs for Contracted Services are reduced after major decommissioning milestones are achieved. For example:

- **Transition of SONGS Programs to SDS –** SDS will assume responsibility for the management of numerous SONGS programs by the end of 2017. Accordingly, the estimated costs for contracted services in the Maintenance and Decommissioning Projects divisions are significantly lower in 2018.

- **Completion of Fuel Transfer Operations –** After all spent fuel has been transferred to the ISFSI, the Operations division and its associated contracted services will no longer be needed.

- **D&D Complete** – Many of the contracted services costs in the Decommissioning Oversight and Site Management & Administration divisions will not be needed after SDS completes its work and the SONGS programs are reduced.

e. Decommissioning Advisor

The Decommissioning Advisor provides subject matter expertise and assistance on various matters, including regulatory issues, spent fuel storage, and project management. Decommissioning Advisor costs are estimated through Period 4 (D&D).

f. DGC Executive Oversight Committee

The SDS D&D contract requires an Executive Oversight Committee composed of five individuals charged with resolving contractual issues. The committee includes one person each from SCE and SDS, and three independent third-party members. SCE and SDS share the costs of the third-party positions.

g. Emergency Preparedness Fees

SCE provides funding to local jurisdictions for the management of radiological emergency preparedness, including planning, response, and recovery activities. Currently, SCE pays fees in accordance with a December 2015 Memorandum of Understanding (MOU) covering a period through 2020. The Emergency Preparedness fees are assumed to be paid annually until all spent fuel has been removed from SONGS.

h. Energy

SCE must purchase energy from the grid to power the site, including loads required for decommissioning work. The energy costs are based on historical retail electricity rates and on projected usage. The projected usage was prepared by SCE Engineering and reflects the major activities in each decommissioning period.

i. Environmental Permits And Fees

SONGS must comply with a variety of environmental regulations and maintain numerous permits, which involve the payment of fees. These permits and associated fees include: (1) the State Water Resource Control Board National Pollutant Discharge Elimination System (NPDES) permit fees and Stormwater Pollution Prevention Plan (SWPPP) fees; (2) State of California Board of Equalization mixed waste fees; (3) fees for the California Department of Environmental Health Permit, which includes the permit for Underground Storage Tanks; (4) Air Pollution Control District Permit (APCD) fees; (5) Diesel Generator permit fees; (6) California Coastal

Commission fees; (7) Refrigerant Management Program; and (8) Kelp consortium costs for monitoring and surveying ocean kelp.

During the D&D period, SDS will be responsible for certain permits and fees, including the NPDES permit, mixed waste fee, SWPPP fee, and APCD permit. However, SCE will continue to maintain other permits and incur other fees (e.g. Department of Environmental Health fees, Diesel Generator air permits, CCC fees, and Refrigerant Management Program fees) through this period.

j. Ground Water Monitoring

SCE is required to monitor the ground water beneath the site for the presence of tritium. The costs include sampling, analysis, and monitoring performed by third-party contractors and will be required through the end of SONGS decommissioning. During the D&D period, SDS will assume responsibility for ground water monitoring.

k. Information Technology

Information Technology (IT) costs include SONGS software and network licenses, internal technical support, and payments to network service providers. IT costs are expected to decrease after 2018 after one-time IT projects are completed, and ongoing support costs will be reduced after 2019.[42]

l. Insurance

NRC regulations require that SCE maintains a minimum level of nuclear liability and property insurance, including Nuclear Property Insurance (provided by Nuclear Electric Insurance Limited) and Nuclear Liability Insurance (provided by American Nuclear Insurers).[43] SCE must maintain nuclear-related insurance coverage until the spent nuclear fuel is removed from the SONGS site.[44]

In addition, SCE also maintains General Liability Insurance and Excess Workers' Compensation Insurance, the cost of which is generally a function of SONGS headcount. Historical costs were used as the primary basis to estimate future insurance costs.

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[42] Separately, SONGS also incurs costs associated with support provided by SCE corporate IT personnel and resources. The costs for such additional IT support are provided via a Service Level Agreement with SCE.

[43] Should the Participants choose to reduce current insurance coverage amounts, the future premiums would be reduced accordingly. In December 2017, the Participants received an exemption from the NRC allowing them to reduce insurance coverage.

[44] Insurance requirements per NRC regulations 10 C.F.R § 50.54(w) and 10 C.F.R § 140.11.

m. Third Party Legal

SCE retains outside counsel as necessary to handle legal matters that require specific expertise, or when legal matters require additional resources. For example, SCE engaged outside counsel to support decommissioning licensing proceedings before the NRC, and environmental/land use permitting proceedings before the CCC, CSLC, and other government agencies.

n. NRC Fees

The NRC charges two different types of fees to nuclear reactor licensees: (1) annual fees (Part 171 Fees), and (2) inspection fees (Part 170 Fees). The Part 171 Fees are fixed annual payments per licensee (i.e., an annual fee for each SONGS unit), including nuclear plants that have been permanently retired. The Part 171 fees are to cover generic (i.e., non-licensee specific) activities performed by the NRC. In contrast, the NRC charges licensees Part 170 Fees based on the time it spends on performance reviews, evaluations, incident investigations, and other activities that are specific to an individual licensee.

o. Office Space

Following the completion of major D&D, SCE will need to lease office space for the remaining employees as all the existing office space on the SONGS site will have been removed. The costs to install trailers and annual lease payments are included in the estimate. During major D&D, SDS is responsible for providing SCE's office space.

p. Security Related Expenses

Security Related Expenses include uniforms, weapons, ammunition, and other supplies and equipment to support the SONGS Security Force, as well as background investigations, training costs, and vendor support.

q. Severance

Under the California Nuclear Facilities Decommissioning Act of 1985,[45] SCE employees at SONGS who are severed as a result of the shutdown and permanent retirement of SONGS are eligible for severance benefits. These benefits include lump sum cash payments based on years of service, outplacement services, and reimbursement for educational expenses.

[45] California Public Utilities Code § 8322(g).

r. Site Lease And Easements

SCE makes annual lease and easement payments to the Navy for the SONGS plant site and Mesa, and to the CSLC for the SONGS offshore conduits. The current site lease with the Navy ends in 2024. As previously discussed, SCE expects to negotiate a new lease to cover the period after 2024 through the end of Period 7 (ISFSI Demolition and Final Site Restoration). The rate per acre in the new plant site lease agreement is expected to increase to account for the fair market value of the property.

The Mesa lease payments to the Navy are expected to remain consistent with the current agreement until Mesa Parcels 5, 6, and 7 are returned to the Navy in 2021. The conduits lease payments to the CSLC are expected to remain consistent with the current agreement, which includes periodic increases in lease payments, through the end of Period 7 (ISFSI Demolition and Final Site Restoration).

s. Water

Utilities includes expenses for water provided by the South Coast Water District (SCWD) Joint Regional Water Supply System (JRWSS). Costs were estimated based on historical recorded costs.

t. Utility Staff Health Physics Supplies

Health Physics (also referred to as HP or Radiation Protection) supplies, including personal radiological monitoring and protection equipment, are used by personnel performing work in radiological areas of the plant. Beginning in 2018, SDS will assume responsibility for the radiation protection program. SCE will resume responsibility after the D&D work is performed. Minimal Health Physics supplies will be needed to support the ISFSI only staff as virtually all contaminated materials will have been removed from the site.

u. Loading Spent Fuel And GTCC Waste To DOE

Under the Standard Contract with the DOE, SCE is responsible for transferring canisters from the ISFSI and loading them into DOE shipping containers on-site. The estimate assumes the DOE will accept the loaded canisters and that a “dry fuel transfer” facility is not necessary. The DOE will take title to the waste after it is loaded onto the DOE’s transport device and the carrier signs for the shipment at the plant site. For purposes of the 2017 DCE, DOE loading costs are assumed to equal approximately 50% of the costs to load and transfer the spent fuel to the ISFSI. The timing of the DOE loading costs is based on the assumed Spent Fuel Shipping Schedule (Appendix A).

3. Service Level Agreements For Administrative & General Expenses

The 2014 DCE included 5% on all estimated costs to account for SCE's administrative and general (A&G) expenses supporting the SONGS decommissioning project. Beginning in 2016, SCE started to develop Service Level Agreements (SLAs) between the SONGS Participants and the SCE departments that support SONGS decommissioning. The SLAs are intended to provide additional transparency with respect to types of costs and level of support needed. There are separate SLAs for each SCE department supporting SONGS (e.g., Human Resources, IT, Legal, CPUC Regulatory Affairs). Beginning in 2029, after Period 4 is completed, corporate support functions are estimated in the A&G line item in lieu of separate SLAs, and is calculated as 5% of all other 2029-2051 estimated costs. The table below summarizes the SLAs and their associated estimated costs.

TABLE 14 SERVICE LEVEL AGREEMENT (A&G) COST ESTIMATE
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete 2017 - 2028 (2017$)	Estimate To Complete 2029 - 2051 (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**Service Level Agreements (A&G)**					
2	Audit Services	$ -	$ 9,893	$ -	$ 9,893	$ 9,404
3	Controllers	-	12,193	-	12,193	11,587
4	Corporate Communications	228	1,933	-	2,161	2,043
5	Corporate Security	-	2,878	-	2,878	2,754
6	CPUC Regulatory Affairs	-	10,982	-	10,982	10,444
7	Decommissioning Finance	1,128	718	-	1,846	1,760
8	Environmental Policy	-	1,833	-	1,833	1,726
9	Environmental Services	107	2,243	-	2,349	2,211
10	Human Resources	-	8,005	-	8,005	7,588
11	Information Governance	-	1,092	-	1,092	1,033
12	Information Technology	7,037	24,820	-	31,857	30,461
13	Legal	-	10,883	-	10,883	10,226
14	Local Public Affairs	-	764	-	764	719
15	Real Properties	247	659	-	906	856
16	Risk Management	-	300	-	300	283
17	Short Term Incentive Plan (STIP)	-	6,050	-	6,050	5,684
18	Supply Management	1,375	9,341	-	10,716	10,147
19	Tax	-	1,874	-	1,874	1,787
20	Transportation Services	525	4,989	-	5,514	5,308
21	Treasurers	-	3,672	-	3,672	3,461
22	A&G (2029 - 2051)	-	-	51,874	51,874	48,732
23	**Service Level Agreements (A&G) Total**	**$ 10,647**	**$ 115,122**	**$ 51,874**	**$ 177,643**	**$ 168,212**

4. DGC Staffing

[redacted]

[redacted]

F. 2017 DCE Costs By NRC Cost Category

SONGS distributed projects are classified into one of the following three NRC cost categories: (1) License Termination (LT); (2) Spent Fuel Management (SNF); and (3) Site Restoration (SR). License Termination activities are those required to decontaminate the site and reduce residual radioactivity in order to terminate the NRC licenses pursuant to 10 C.F.R § 50.75(c). License termination activities are expected to be completed in 2028, following the SDS D&D work, and NRC approval of the partial site release.

Spent Fuel Management activities are those required to operate and maintain the on-site spent fuel storage facilities until such time the spent fuel is removed by the DOE, in accordance with 10 C.F.R § 50.54(bb). The decommissioning of the ISFSI after the spent fuel is transferred offsite (10 C.F.R § 72.30) is also classified as a Spent Fuel Management activity.

The remaining distributed costs are classified as Site Restoration costs, which are primarily driven by the terms of the easement and lease agreements with the Navy and CSLC. Site Restoration distributed projects include non-radiological decommissioning activities, such as the removal of non-contaminated substructures below 3 feet below grade.

The classification of distributed projects in this DCE to NRC cost categories is generally consistent with how projects were classified in the 2014 DCE.

Undistributed costs are also assigned to NRC cost categories. Certain undistributed cost items are assignable to a single NRC cost category (e.g., 100% of the annual cost to load spent fuel to the DOE is classified as Spent Fuel Management). However, given their nature, there are many other undistributed cost items which support multiple decommissioning activities (e.g., energy costs). These undistributed costs are allocated to License Termination, Spent Fuel Management, and Site Restoration based on the distributed cost amounts in each NRC cost category.[46]

The table below summarizes the 2017 DCE costs by NRC cost category.

[46] The undistributed costs incurred to date were recorded to each NRC cost category based on the allocation percentages assumed in the 2014 DCE.

TABLE 15 2017 DCE BY NRC COST CATEGORY
($ IN THOUSANDS)

	Description	Recorded Through 2016 (Nominal $)	Estimate To Complete (2017$)	Total Estimate At Completion (Nominal /2017$)	Total Estimate At Completion (2014$)
1	**License Termination**				
2	Distributed	[redacted]			$ [redacted]
3	Undistributed				
4	**License Termination Subtotal**				**$ 1,906,728**
5					
6	**Spent Fuel Management**				
7	Distributed	[redacted]			$ [redacted]
8	Undistributed				
9	**Spent Fuel Management Subtotal**				**$ 1,367,361**
10					
11	**Site Restoration**				
12	Distributed	[redacted]			
13	Undistributed				
14	**Site Restoration Subtotal**	**$ 166,324**	**$ 1,098,532**	**$ 1,264,856**	**$ 1,204,476**
15					
16	**Total**	[redacted]			**$ 4,478,566**

G. Contingency

Contingency is used in cost estimates to account for the costs of unplanned events and circumstances that often occur during the performance of a project. As defined in the American Association of Cost Engineers Project and Cost Engineers' Handbook, contingency is "an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."

Examples of costs intended to be covered by contingency include planning and estimating errors and omissions, design development and changes within scope, minor price fluctuations, and variations in the market and environmental conditions. Contingency is not intended to cover all unknowns or unplanned occurrences. For example, contingency usually excludes major scope changes, extraordinary events such as strikes and natural disasters, specified "management reserves" for defined issues, and general price escalation or currency effects.

The consensus in industry literature is that a primary consideration in determining appropriate amounts for contingency on a particular project is the stage of development and level of confidence in the estimated known base project costs. The 2014 DCE used a 25%

contingency factor,[47] which was deemed reasonable by the CPUC in D.16-04-019 given the then-existing level of uncertainty in the then-current DCE.[48]

Given the current stage of decommissioning, a lower contingency factor is warranted in some areas. Kenrich and knowledgeable SCE personnel reviewed each major category of costs and determined an individual contingency factor for each group. In determining the contingency factors for each cost grouping, consideration was given to contracting status (e.g., ISFSI and D&D work are under contract), technical complexity, estimating approach, and other variables.

The remaining work associated with ISFSI is primarily the loading and transfer of spent fuel canisters to the ISFSI. The associated contingency factor reflects that this work is under contract and benefits from significant learning and industry experience over many decades. The D&D work is also under contract, following a rigorous competitive procurement process. However, the contingency factor for this work also accounts for the significant influence of site-specific factors on D&D work. For other distributed work, not currently under contract and planned to occur in the relative distant future, the same 25% contingency factor used in the 2014 DCE was used in this DCE. With regard to undistributed labor and non-labor costs, the associated contingency factors account for a significantly more rigorous process used to develop the estimates contained in this DCE. In contrast to the 2014 DCE, the estimated headcount and non-labor costs for each division were subject to more substantial and iterative internal review and updating processes.

The table below summarizes the contingency factor applied to the to-go costs for each estimate.

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[47] Contingency of 25% was applied to all costs in the 2014 DCE with the following exceptions: 2013 and 2014 Actual Expenditures 0%; Department of Navy Easement Payments 15%; Hazardous and Asbestos Wastes 50%; Site Characterization Surveys 15%; Temporary Facilities 15%; Backfill and Compaction 15%.

[48] Specifically referring to SONGS in its 2012 NDCTP decision, the CPUC stated, "[t]he Commission finds the reasonableness of a contingency amount is significantly related to the stage of decommissioning and the activities projected, including particular site-specific challenges. Consequently, the reasonable contingency factor may vary between nuclear plants and at different stages of decommissioning." (D.14-12-082 at 38). Further, in its April 20, 2017 proposed decision pertaining to PG&E's updated cost estimates for the decommissioning of its two nuclear power plants, the CPUC specifically noted that PG&E use of a 25% contingency factor for Diablo Canyon raised questions in light of other information which had been supplied by PG&E's third-party decommissioning cost consultant, TLG Services, Incorporated (TLG). Specially, TLG estimated contingency on a line item basis and the resulting composite contingency factor was 17.4%.

TABLE 16 CONTINGENCY FACTORS APPLIED IN 2017 DCE

2017 DCE Category	Contingency Factor
Recorded Costs Through September 2017	0%
ISFSI & Fuel Transfer Operations	[redacted]
[redacted]	
Substructure Removal	25%
Other Projects	15-25%
Offshore Conduit Removal	25%
ISFSI Demolition	25%
Final Site Restoration	25%
Undistributed Labor	10%
Undistributed Non-Labor	15%
Service Level Agreements	10%

The composite contingency factor included in the 2017 DCE is approximately [redacted] percent of base estimated costs.

TABLE 17 CONTINGENCY INCLUDED IN THE SONGS 2&3 2017 DCE ($ IN THOUSANDS)

	Description	2017 DCE (Nominal /2017$)	2017 DCE (2014$)
1	Base Estimated Costs	[redacted]	
2	Estimated Contingency		
3	**Subtotal Estimated Costs**	**$ 3,518,663**	**$ 3,322,641**
4	Recorded Costs	1,183,601	1,155,925
5	**Total DCE Value**	**$ 4,702,264**	**$ 4,478,566**

VI. Additional Discussion Regarding The Project Schedule

The SONGS decommissioning project schedule defines the sequence and timing of activities, the completion dates for major project milestones, and the duration of each decommissioning period. The 2017 DCE is presented in 2017 dollars. These constant dollars are spread over the duration of the SONGS entire decommissioning project based on the 2017 DCE project schedule.[49]

In accordance with the contract, SDS has developed a baseline schedule for completing its major D&D and achieving partial site release. SCE incorporated SDS's Baseline Schedule

[49] To assess the adequacy of the amount of funds residing in the Nuclear Decommissioning Trust, the annual constant dollar cash flows are escalated and discounted to present value.

into the overall decommissioning project schedule on which the 2017 DCE is based. The completion dates were mapped to corresponding 2017 DCE milestones.

As described earlier, the decommissioning schedule is comprised of seven (7) periods. Each period is generally defined by the major focus of activity on-site, as well as the licensing status of the plant (i.e., from an NRC perspective). SONGS is currently planning and preparing for the physical decommissioning of the plant facilities (Periods 1 and 2). The major D&D work is expected to begin in 2019 and estimated to be completed by late 2028 (Periods 3 and 4). At the conclusion of the major D&D work, all structures, systems, and components on-site will have been removed to at least 3 feet below grade and the NRC Part 50 license will have been reduced to the ISFSI area only.

From 2029 until 2046, when the work to remove the below-grade structures begins, the only significant activity at the site will be the transfer of spent fuel canisters to the DOE (Period 5). During this period, SCE will become informed regarding the regulatory and landowner "end-state" requirements for the SONGS site. The demolition and removal of the ISFSI and remaining below-grade structures will be performed after 2046 (Periods 6 and 7). This timing of this work is determined in part by the anticipated date by which the DOE is expected to have removed all SONGS spent fuel. The DOE is currently assumed to begin removing SONGS 2&3 spent fuel in 2034 and complete the removal of all fuel by 2049. Final site restoration and license termination is projected to be completed by 2051.

Two critical milestones include the completion of spent fuel transfer operations (i.e., transfer of all spent fuel from the wet pools to the ISFSI) in mid-2019 and the completion of major D&D work in late 2028. After each of these milestones, SONGS's licensing status and regulatory requirements change such that the associated costs to manage and support (e.g., operations, maintenance, security, management, and contract oversight) the decommissioning of the site will be substantially reduced.

SCE currently anticipates commencing spent fuel transfer operations in 2018 and is targeting completion in early to mid-2019. Fuel transfer operations are relatively complex, subject to extensive regulatory oversight, and intended to be performed 24 hours per day, seven days per week. Accordingly, for purposes of this DCE, SCE included schedule margin in its determination of the June 1, 2019 milestone completion date.

The critical activities driving the overall duration of major D&D work are the removal of the nuclear steam supply system (NSSS) equipment (e.g., reactor vessels, steam generators, reactor coolant pumps) from inside the containment buildings, and then the decontamination, demolition, and removal of the containment buildings. The decontamination, demolition, and removal of other SONGS buildings and facilities will be performed concurrently.

SCE and SDS are continuing to plan and schedule major D&D work. Currently, SDS intends to complete the physical decommissioning work in 2025 and obtain final NRC approval of the final site survey and partial site release in 2026. SDS's schedule is currently based on performing the preparation and segmentation of the reactor vessel internals and NSSS large component removal at both Units 2 and 3 in parallel. These activities include relatively high-risk

cutting and material handling operations. As another example of uncertainty that is currently inherent in the major D&D schedule, SCE is currently planning for increased radiological decontamination efforts associated with the below-grade structures that will remain at SONGS after SDS completes its work. Accordingly, for purposes of this DCE, SCE has included schedule margin in its determination of the planned completion date of major D&D in late 2028.[50]

VII. Waste Disposal

The disposition of waste is a significant activity in the decommissioning of SONGS. A brief description of the waste to be generated from the SONGS decommissioning process is described below. In addition, the estimated quantity of each type of waste is summarized in Table 18 below.

Spent Nuclear Fuel – Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the removal and permanent disposal of all SONGS spent nuclear fuel. In the 2014 DCE, SCE assumed the DOE would begin accepting spent fuel from domestic commercial nuclear power plants in 2024 at the rate published in DOE's July 2004 Acceptance Priority Ranking & Annual Capacity Report. Due to DOE inactivity in the past four years, SCE revised its spent fuel shipping schedule for the 2017 DCE to assume that the DOE will begin accepting spent fuel from the nuclear industry in 2028.

GTCC Waste – GTCC waste will be generated when SDS segments the reactor vessel internals. Additional GTCC waste may reside in the spent fuel pools. GTCC waste cannot be disposed of in a federally licensed low-level radioactive waste (LLRW) disposal facility. As explained above, courts have held that the DOE must accept GTCC waste, but currently there is no disposal facility in the U.S. that is licensed to accept it. Therefore, GTCC waste will be packaged and stored in licensed canisters on the SONGS ISFSI until final disposal.

Low-Level Radioactive Waste (LLRW) – 10 C.F.R. § 61 outlines the requirements for LLRW and identifies the criteria for the classifications of waste materials that can be accepted at federally licensed LLRW disposal facilities. SDS will characterize, package, and transport offsite the Class A, Class B, and Class C waste.

Exempt Waste – It is assumed that some waste generated during the decommissioning of SONGS will receive NRC approval to be disposed of at a facility that accepts very low-level waste. According to the NRC, "10 CFR 20.2002 is available for use by licensees for wastes that typically are a small fraction of the Class A limits contained in Part 61, and for which the extensive controls in Part 61 are not needed to ensure protection of public health and safety and the environment. Thus, 10 CFR 20.2002 provides an alternative, safe, risk-informed disposal

[50] The 2028 date is generally consistent with the schedule that was assumed in the 2014 DCE.

method for these materials, which are frequently called 'very low-level waste' (VLLW), or 'low-activity waste' (LAW)."[51]

Non-Radiologically Contaminated Waste – Radiologically clean concrete or debris will be disposed of at an out of state Class III landfill. This material will be scanned for radiological contamination prior to leaving SONGS to meet all applicable regulatory requirements. Non-contaminated reinforcing and structural steel may be recycled.

Non-Radiologically Contaminated Hazardous and Industrial Waste Disposal – Lead shielding and other hazardous materials and chemicals will be removed and properly disposed of during decommissioning. Non-Radioactive contaminated surfaces coated with tightly adhering and undamaged lead-based paint will be removed as non-hazardous building demolition debris.

Table 18 summarizes the estimated waste disposal quantities by class for the remainder of SONGS decommissioning.

TABLE 18 REMAINING WASTE DISPOSAL QUANTITIES

	Description	Period 2 Transition and Pool Storage (lbs)	Periods 3 & 4 D&D (lbs)	Period 5 Dry Storage (lbs)	Period 6 Civil Works Project (lbs)	Period 7 ISFSI Demolition & Final Site Restoration (lbs)	Total (lbs)
1	Start	1/1/2017	1/1/2019	1/1/2029	1/1/2046	1/1/2050	
2	End	12/31/2018	12/31/2028	12/31/2045	12/31/2049	12/31/2051	
3	Duration (Years)	2.0	10.0	17.0	4.0	2.0	
4	**Class B, C, GTCC**						
5	Class B	-	69,320	-	-	-	69,320
6	Class C	5,700	inc	-	-	-	5,700
7	GTCC	-	222,800	-	-	-	222,800
8	**Class B, C, GTCC Subtotal**	**5,700**	**292,120**	**-**	**-**	**-**	**297,820**
9	**Class A**						
10	Class A	-	395,096,463	-	-	502,383	395,598,846
11	Class A - Containerized Waste	7,950	inc	-	-	-	7,950
12	**Class A Subtotal**	**7,950**	**395,096,463**	**-**	**-**	**502,383**	**395,606,796**
13	**Other**						
14	Out of State Landfill / Exempt	-	489,594,000	-	1,074,296,250	394,648,923	1,958,539,173
15	Scrap Metal Recycler	-	105,391,000	-	71,736,000	10,325,800	187,452,800
16	**Other Subtotal**	**-**	**594,985,000**	**-**	**1,146,032,250**	**404,974,723**	**2,145,991,973**
17							
18	**Waste Total**	**13,650**	**990,373,583**	**-**	**1,146,032,250**	**405,477,106**	**2,541,896,589**

[51] "Low-Level Waste Disposal Under 10 C.F.R. § 20.2002." U.S. NRC, 21 September 2017, https://www.nrc.gov/waste/llw-disposal/10cfr20-2002-info.html, accessed December 1, 2017.

VIII. References

1. Energy*Solutions*, "2014 Decommissioning Cost Analysis of the San Onofre Nuclear Generating Station Units 2&3," September 5, 2014

2. August 20, 2015 letter from NRC to SCE Vice President and Chief Nuclear Officer, Mr. Thomas J. Palmisano (ADAM Accession No.: ML15204A383)

3. Application 14-12-007 "Joint Application Of Southern California Edison Company (U 338-E) And San Diego Gas & Electric Company (U 902-E) For 2014 SONGS Units 2&3 Decommissioning Cost Estimate And Related Decommissioning Issues," December 10, 2014

4. California Public Utilities Commission Decision 16-04-109, "Decision Approving Decommissioning Cost Estimate," April 21, 2016

5. State of California State Lands Commission, "Lease P.R.C. No. 4862.1," November 19, 1984

6. Department of the Navy, "Grant of Easement," May 1964

7. State of California, Executive Order D-62-02, September 2002

8. U.S. Nuclear Regulatory Commission, "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, February 2005

9. California Public Utilities Commission Proposed Decision A.16-03-006, "Decision Approving Decommissioning Cost Estimate," April 20, 2017

Appendix A

Spent Fuel Shipping Schedule

SONGS Units 1, 2, and 3
Spent Fuel Shipping Schedule
2028 DOE Acceptance
(as of 1/2/2018)

	On-Site Inventory (Beginning of Year)					On-Site Transfers (During Year)		Off-Site Transfers (During Year)			
	Unit 1 Fuel Assemblies at Morris	Unit 1 Fuel Assemblies in ISFSI	Units 2 & 3 Fuel Assemblies in Pools	Units 2 & 3 Fuel Assemblies in ISFSI	Units 1, 2, & 3 Canisters in ISFSI*	Units 2 & 3 Fuel Assemblies Transferred to ISFSI	Units 2 & 3 Canisters Transferred to ISFSI	Unit 1 Assemblies Transferred to DOE	Unit 2 Assemblies Transferred to DOE**	Unit 3 Assemblies Transferred to DOE**	Units 1, 2, & 3 Canisters Transferred from ISFSI to DOE*
2016	270	395	2,668	792	50	-	-	-	-	-	-
2017	270	395	2,668	792	50	-		-	-	-	-
2018	270	395	2,668	792	110	2,220	60	-	-	-	-
2019	270	395	448	3,012	170	448	13	-	-	-	-
2020	270	395	-	3,460	182	-	-	-	-	-	-
2021	270	395	-	3,460	182	-	-	-	-	-	-
2022	270	395	-	3,460	182	-	-	-	-	-	-
2023	270	395	-	3,460	182	-	-	-	-	-	-
2024	270	395	-	3,460	182	-	-	-	-	-	-
2025	270	395	-	3,460	182	-	-	-	-	-	-
2026	270	395	-	3,460	182	-	-	-	-	-	-
2027	270	395	-	3,460	182	-	-	-	-	-	-
2028	270	395	-	3,460	182	-	-	96	-	-	4
2029	270	299	-	3,460	178	-	-	48	-	-	2
2030	270	251	-	3,460	176	-	-	120	-	-	5
2031	270	131	-	3,460	171	-	-	48	-	-	2
2032	270	83	-	3,460	169	-	-	48	-	-	2
2033	270	35	-	3,460	167	-	-	-	-	-	-
2034	270	35	-	3,460	167	-	-	35	48	48	6
2035	270	-	-	3,364	161	-	-	-	192	96	12
2036	270	-	-	3,076	149	-	-	-	120	168	12
2037	270	-	-	2,788	137	-	-	-	48	72	5
2038**	270	-	-	2,668	132	-	-	-	74	111	5
2039	270	-	-	2,483	127	-	-	-	111	111	6
2040	270	-	-	2,261	121	-	-	-	111	74	5
2041	270	-	-	2,076	116	-	-	-	-	-	-
2042	270	-	-	2,076	116	-	-	-	111	111	6
2043	270	-	-	1,854	110	-	-	-	74	111	5
2044	270	-	-	1,669	105	-	-	-	111	74	5
2045	270	-	-	1,484	100	-	-	-	-	-	-
2046	270	-	-	1,484	100	-	-	-	222	222	12
2047	270	-	-	1,040	88	-	-	-	74	74	4
2048	270	-	-	892	84	-	-	-	222	222	12
2049	270	-	-	448	72	-	-	-	208	240	13
2050***	270	-	-	-	59	-	-	270	-	-	13
2051	-	-	-	-	-	-	-	-	-	-	-

* Excluding GTCC Waste
** Before 2038, SONGS 2 & 3 fuel assemblies shipped in Areva 24-PTH canisters Beginning in 2038, SONGS 2 & 3 fuel assemblies shipped in Holtec MPC canisters
*** Unit 1 fuel assemblies transferred to DOE from GE facility in Morris, Illinois in TADS (21 assemblies per TAD)

Appendix B

Detailed Project Schedule

San Onofre Nuclear Generating Station Units 2 and 3 Decommissioning Schedule (Period 2 – 4)

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Based on SONGS DS Schedule Submitted 09/14/2017

SAN ONOFRE

2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028

2014 DCE Containment NSSS Removal Duration

2017 Containment Nuclear Steam Supply Systems Removal

U2 and U3 Containment NSSS Baseline

Unit 2 Containment

U2 – Containment Prep (1/19 – 10/19)
U2 – RV Internals Segmentation (10/19 – 1/21)
U2 – RV Shell (1/21 – 10/21)
U2 – Large Component Removal (1/24 – 4/22)

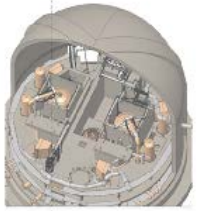
Complex Cutting and Handling Operations
Performed in Parallel in lieu of Series as in 2014 DCE

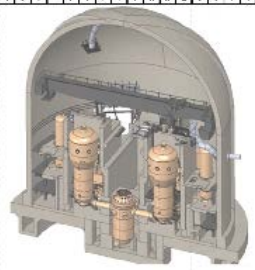
Unit 3 Containment

U3 – Containment Prep (2/19 – 10/19)
U3 – RV Internals Segmentation (10/19 – 1/20)
U3 – RV Shell (1/21 – 4/22)
U3 – Large Component Removal (1/23 – 5/22)

7/20 U1 Reactor Pressure Vessel
1/21 Final GTCC Offload

Additional Six Months to Manage Project Risk





2018 | 2019

2014 DCE Dry Storage Fuel Transfer Campaign

2017 Dry Storage Fuel Transfer Campaign

Spent Fuel Loading Services (10/18 – 12/18)
Closeout and Demobilization

Additional Five Months Due to 24/7 Dual Plant Spent Fuel Offload

2014 DCE Containment Decontamination and Demolition

2017 Containment Decontamination and Demolition

U2 and U3 Containment Decontamination & Demolition Baseline

U2 Containment Decon (12/22 – 6/23)
U2 Interior Demo (6/23 – 6/23)
U3 Containment Decon (6/23 – 12/23)
U3 Interior Demo (12/23 – 12/24)
Power Block Area Backfill (6/24 – 10/24)
U2 Open Air Demo (7/24 – 8/25)
U3 Open Air Demo (10/24 – 12/25)
U2 Additional Decon (8/25 – 12/25)
U3 Additional Decon (12/25 – 3/26)

Additional Decontamination of Remaining Sub-Structure Surfaces to Leave as Clean as Practical for Subsequent Removal in 2046 – 2049

Risk Duration for Segregating, Handling and Packaging Concrete Rubble if not Considered for Backfill. Contract and Strategic Change Under Consideration.
Areas depicted: and or

Auxiliary Radwaste Building

Auxiliary Control Building

Unit 2 – Turbine Building

Unit 3 – Turbine Building

Unit 2 – Safety Equipment Building

Unit 3 – Safety Equipment Building

Unit 2 – Penetration Building

Unit 3 – Penetration Building

Unit 2 – Fuel Handling Building

Unit 3 – Fuel Handling Building

Auxiliary Building Decontamination & Demolition

Aux Radwaste Planning & Characterization (10/19 – 4/20)
Aux Radwaste Systems Removal (4/20 – 8/21)
Aux Radwaste Decon (8/21 – 4/22)
Aux Radwaste Building Demo (11/22 – 6/23)
Aux Radwaste Additional Decon (7/23 – 7/25)
Install Tents (8/21 – 10/21)
Remove Tents (6/23 – 7/23)
Aux Control Planning & Characterization (10/21 – 10/21)
Aux Control Systems Removal (10/21 – 4/22)
Aux Control Decon (4/22 – 5/22)
Aux Control Building Demo (5/22 – 11/22)
Aux Control Additional Decon (7/23 – 8/23)

Turbine Building Decontamination & Demolition

U2 Planning & Characterization (7/20 – 10/20)
U2 Decon (10/20 – 12/20)
U2 Systems Removal (12/20 – 8/21)
U2 Building Demo (12/21 – 2/22)
U2 Additional Decon (4/22 – 4/24)
U3 Planning & Characterization (7/20 – 7/21)
U3 Systems Removal (7/21 – 4/22)
U3 Decon (4/22 – 7/22)
U3 Building Demo (7/22 – 8/23)
U3 Additional Decon (10/23 – 1/24)

Systems Removal & Decon

Planning & Characterization (4/20 – 7/20)
Systems Removal (7/20 – 4/21)
Decon (4/21 – 8/21)
Remove Safety Injections Systems (8/21 – 10/21)

Interior – Open Air Demo

Interior Demo (7/24 – 5/24)
Open Air Demo (1/24 – 1/25)
Additional Decon (1/25 – 3/25)

Systems Removal & Decon

Planning & Characterization (1/24 – 4/24)
Systems Removal (4/24 – 8/24)
Decon (8/24 – 9/24)
Remove Safety Injections Systems (9/21)

Interior – Open Air Demo

Interior Demo (6/23 – 1/24)
Open Air Demo (12/24 – 1/25)
Additional Decon (1/25 – 3/25)

Systems Removal & Decon

Planning & Characterization (7/22 – 10/22)
Systems Removal (10/22 – 1/23)
Decon (1/23 – 4/23)

Interior – Open Air Demo

Interior Demo (4/23 – 6/23)
U2 FSS (CVS) Penetration (7/24)
Open Air Demo (11/24 – 12/24)
Additional Decon (2/25 – 4/25)

Systems Removal & Decon

Planning & Characterization (4/23 – 6/23)
Systems Removal (6/23 – 7/23)
Decon (7/23 – 8/23)

Interior – Open Air Demo

Interior Demo (11/23 – 11/23)
U3 FSS (CVS) Penetration (8/24)
Open Air Demo (11/24 – 12/24)
Additional Decon (2/25 – 4/25)

Systems Removal & Decon

Planning & Characterization (1/20 – 4/21)
Systems Removal (4/21 – 1/22)
Decon (1/22 – 4/22)

Interior – Open Air Demo

Interior Demo (1/23 – 6/24)
U2 FSS (CVS) Fuel Handling (7/24)
Open Air Demo (1/24 – 7/25)
Additional Decon (6/24 – 7/25)

Systems Removal & Decon

Planning & Characterization (10/20 – 4/21)
Systems Removal (4/21 – 12/22)
Decon (12/22 – 5/22)

Interior – Open Air Demo

Interior Demo (6/23 – 6/23)
U3 FSS (CVS) Fuel Handling (7/24)
Open Air Demo (10/24 – 11/24)
Additional Decon (1/25 – 3/25)

Additional Decon of These Ancillary Buildings May Change Means and Methods to Rip-and-Ship

Intake Area Backfill (12/22 – 3/23)

OCA Area Backfill (7/23 – 8/23)

P epare LTP (1/19 – 12/22)

7/20 Remove Unit 1 Reactor Vessel from Site (Unit 1 DCE)

12/22 Submit License Termination Plan to NRC

NRC Review of License Termination Plan (1/23 – 7/24)

7/24 License Termination Plan NRC Approval

LTP ASLB Hearing Support (6/23 – 1/25)

FSS Preparation (8/25 – 11/25)

NRC FSS Approval Period (1/26 – 4/26)

5/26 Final Status Survey Approval and License Termination

6/26 Final Acceptance Certification

Tertiary Major Finish Milestones

4/21 Nuclear Security SAS Building
5/21 864/865 Buildings
5/21 862/863 Buildings
5/21 Maintenance Building
6/21 U2 Diesel Generator Building
6/21 Fire Protection Tanks
6/21 Outage Control Building
6/21 AWS Building
6/21 841 / 842 Modulars
10/21 U2 Main Transformer
11/21 K60 Warehouse
11/21 K70 South Security Building
12/21 K40 / K50 Office Building
1/22 K10 / K20 / K30 Buildings
2/22 U3 Diesel Generator Building
3/22 U3 Main Transformer
5/22 Intake Area / Structure
11/22 Full Flow Demineralizers
9/23 Removal of Off-Shore Components

2/25 U3 Diesel Generator Tanks
3/25 U2 Diesel Generator Tanks
4/25 T10 / T20 Shop
6/25 HazMat Building
6/25 Rems Staging Area
6/25 OCA Parking Yard Utilities
6/25 Multi-Purpose Building 60
6/25 Yard / Drains / Utilities
6/25 Security Building L50
7/25 Sewage Plant

Project Closeout

- Final Status Surveys
- Contract Final Acceptance
- Administrative Closeout

Phase Legend:

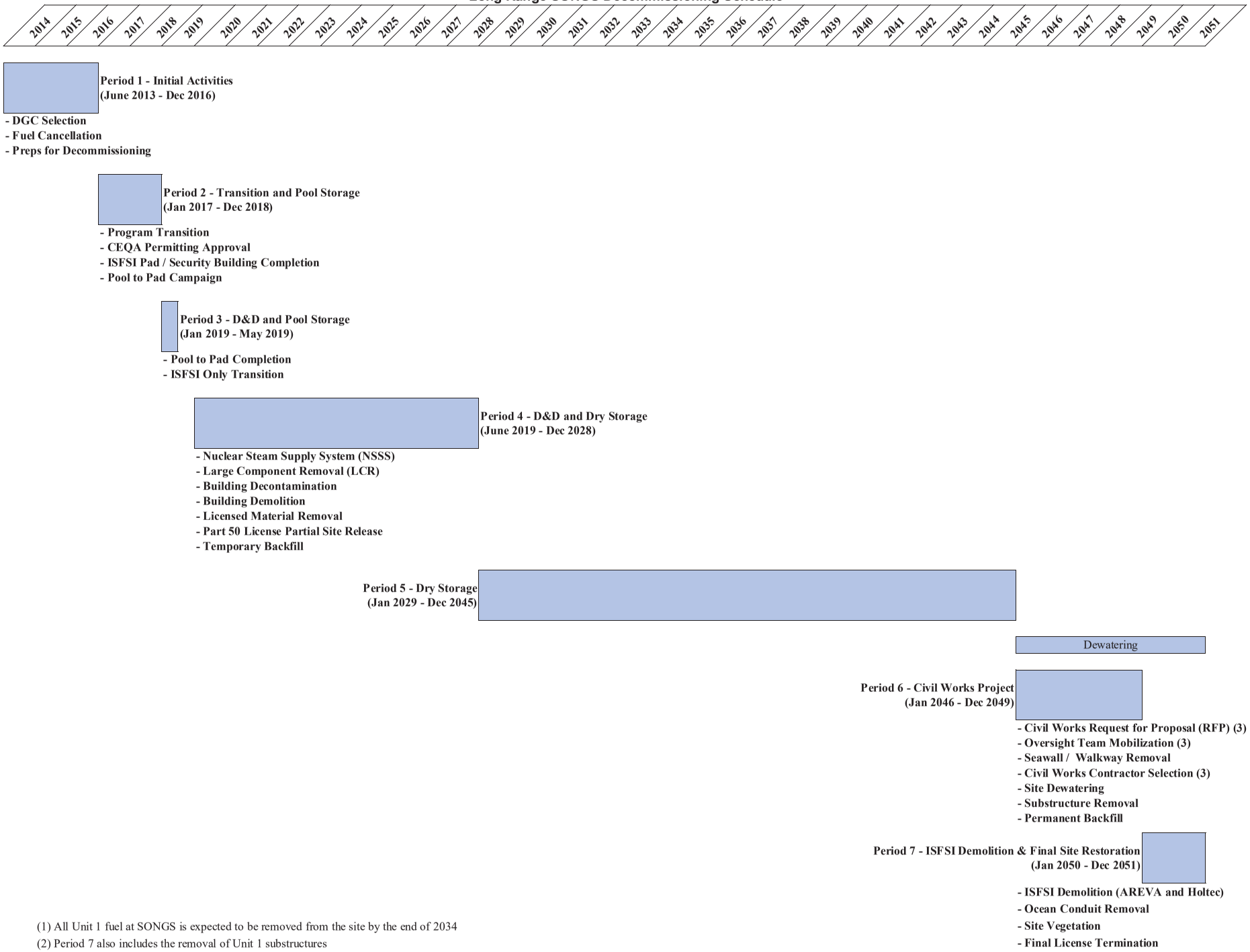
- 2017 Major Work Activity
- 2017 Period of Work Performed
- 2014 DCE Equivalent Period of Work Performed

Activity Legend:

Projected Baseline Plus 12 Months

- Summary
- Planning & Characterization
- Systems Removal
- Decon
- Support Activities
- Open Air Demo
- Combined Demo
- Interior Demo
- Backfill
- Additional Decon (Duration Undefined)

Long Range SONGS Decommissioning Schedule



(1) All Unit 1 fuel at SONGS is expected to be removed from the site by the end of 2034

(2) Period 7 also includes the removal of Unit 1 substructures

(3) These activities occur prior to Period 6

Rev 4 - Issued 12/6/17

Appendix C

Detailed Cost Table

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description		Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
1	**Completed Projects - 2015 NDCTP**			**$ 1,223**	**$ 2,671**	**$ 89,834**	**$ (137)**	**$ -**	**$ 1,563**	**$ -**	**$ 95,154**
2											
3	LT-2-D-2 18	Planning & Design For Cold and Dark		1,888	1,008	14,977	1,054	-	1,373	-	20,299
4	LT-2-D-2 19	Implement Cold and Dark (Repower Site)		2,151	415	52,191	(663)	-	1,522	-	55,615
5	LT-2-D-2 20	Install 12 kV Service Line to Power Temp Power Ring		1,579	2,779	4,746	419	-	758	-	10,281
6	LT-2-D-2 21	Drain & De-Energize Non-Essential Systems (DEC Process)		2,363	946	1,299	14	-	1,487	-	6,111
7	LT-2-D-2 29	Implement Control Room Modifications (Command Center Relocation)		-	4	340	3	-	3	-	350
8	**Completed Activities - Initial D&D Activities Subtotal**			**$ 7,981**	**$ 5,152**	**$ 73,553**	**$ 826**	**$ -**	**$ 5,143**	**$ -**	**$ 92,655**
9											
10	LT-2-D-2 26	Install Spent Fuel Pool System Modifications - Unit 2		139	2,814	1,159	31	-	129	-	4,271
11	LT-2-D-2 27	Install Spent Fuel Pool System Modifications - Unit 3		139	2,814	1,159	31	-	129	-	4,271
12	**Completed Activities - Spent Fuel Islanding Subtotal**			**$ 277**	**$ 5,627**	**$ 2,317**	**$ 63**	**$ -**	**$ 258**	**$ -**	**$ 8,543**
13											
14	LT-2-D-2 07	Prepare Defueled Safety Analysis Report (DSAR)		1	-	1,991	8	-	21	-	2,021
15	**Completed Activities - Phase 2 Regulatory Compliance Subtotal**			**$ 1**	**$ -**	**$ 1,991**	**$ 8**	**$ -**	**$ 21**	**$ -**	**$ 2,021**
16											
17	LT-2-D-2 22	Select Decommissioning General Contractor (DGC)		1,219	7	11,842	392	-	809	-	14,270
18	**Completed Activities - DCG RFP & Prep Subtotal**			**$ 1,219**	**$ 7**	**$ 11,842**	**$ 392**	**$ -**	**$ 809**	**$ -**	**$ 14,270**
19											
20	LT-2-D-LOED	[2] Large Organism Exclusion Device Modification		69	1,070	178	(4)	-	51	-	1,364
21	LT-D-SPV	[2] Special Purpose Vehicle Support		-	-	442	-	-	6	-	448
22	LT-3-D-RecB	[2] Records Backlog		-	-	1,807	186	-	20	-	2,014
23	LT-3-D-S&S	[2] Simplification & Streamlining Project		1	6	1,329	33	-	8	-	1,377
24	**Completed Activities - Transition Modifications Subtotal**			**$ 69**	**$ 1,076**	**$ 3,757**	**$ 215**	**$ -**	**$ 84**	**$ -**	**$ 5,202**
25											
26	**Completed Projects And Activities Subtotal**			**$ 10,771**	**$ 14,534**	**$ 183,294**	**$ 1,368**	**$ -**	**$ 7,877**	**$ -**	**$ 217,845**
27											
28	**ISFSI & Fuel Transfer Operations**										
29	SNF-1-D-7 02	Holtec Long Lead Items and Areva Contract Closure	[3]	95	16,342	32,106	(12,796)	-	445	1,026	37,219
30	SNF-2-D-8 07	ISFSI Pad Study		-	-	199	2	-	2	-	203
31	SNF-2-D-8 08	Design ISFSI Expansion, Fuel Inspection, and Oversight	[4]	1,284	103	76,028	2,808	-	916	3,589	84,729
32	SNF-2-D-8 09	Construct ISFSI Expansion		96	5	44,885	267	-	177	4,225	49,655
33	SNF-2-D-8 10	Fabrication of Spent Fuel Canisters - Unit 2	[5]	24	1,696	27,107	8,978	-	568	317	38,690
34	SNF-2-D-8 11	Fabrication of Spent Fuel Canisters - Unit 3	[5]	23	1,696	19,640	8,979	-	490	528	31,357
35	SNF-2-D-8 12	Load Fuel Canisters and Fuel Transfer Operations - Unit 2	[6]	-	-	17,684	-	-	-	2,606	20,290
36	SNF-2-D-8 13	Load Fuel Canisters and Fuel Transfer Operations - Unit 3	[6]	-	-	17,684	-	-	-	2,606	20,290
37	**ISFSI & Fuel Transfer Operations Subtotal**			**$ 1,523**	**$ 19,842**	**$ 235,332**	**$ 8,239**	**$ -**	**$ 2,598**	**$ 14,899**	**$ 282,432**
38											
39	**Decontamination, Demolition, & Disposal**										
40	[redacted]	Prepare Integrated Work Sequence and Schedule for Decommissioning		-	-	[redacted]	-	-	-	[redacted]	[redacted]
41	[redacted]	Modify Containment Access- Unit 2		-	-	[redacted]	-	-	-	[redacted]	[redacted]
42	[redacted]	Modify Containment Access- Unit 3		-	-	[redacted]	-	-	-	[redacted]	[redacted]
43	[redacted]	Remove and Dispose of Missile Shields - Unit 2		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
44	[redacted]	Remove and Dispose of Reactor Head - Unit 2		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
45	[redacted]	Remove and Dispose of Missile Shields - Unit 3		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
46	[redacted]	Remove and Dispose of Reactor Head - Unit 3		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
47	[redacted]	Prepare Activity Specifications - U2		-	-	[redacted]	-	-	-	[redacted]	[redacted]
48	[redacted]	[2] Waste Contracts		-	-	[redacted]	-	-	-	[redacted]	[redacted]
49	[redacted]	Install GARDIAN System		-	-	[redacted]	-	-	-	[redacted]	[redacted]
50	**Decontamination, Demolition, & Disposal - Initial D&D Activities Subtotal**			**$ -**	**$ -**	**$** [redacted]	**$ -**	**$** [redacted]	**$ -**	**$** [redacted]	**$** [redacted]

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
51										
52		Design, Specify, and Procure Special Items and Materials	-	-		-	-	-		
53		Test Special Cutting and Handling Equipment and Train Operators	-	-		-	-	-		
54		Finalize Internals and Vessel Segmenting Details - Unit 2	-	-		-	-	-		
55		Segment, Package and Dispose of Reactor Internals - Unit 2	-	-		-		-		
56		Segment, Package and Dispose of Reactor Internals - Unit 3	-	-		-		-		
57		**Decontamination, Demolition, & Disposal - Internals and Vessel Segmentation Subtotal**	$ -	$ -	$	$ -	$	$ -	$	$
58										
59		Remove Underground Diesel Tank - Unit 2	-	-		-	-	-		
60		Remove Underground Diesel Tank - Unit 3	-	-		-	-	-		
61		Remove and Dispose of Spent Fuel Storage Racks - Unit 2	-	-		-		-		
62		Remove and Dispose of Spent Fuel Storage Racks - Unit 3	-	-		-		-		
63		Drain Spent Fuel Pool and Process Liquid Waste - Unit 2	-	-		-	-	-		
64		Drain Spent Fuel Pool and Process Liquid Waste - Unit 3	-	-		-	-	-		
65		Remove Protected Area Security Fencing	-	-		-	-	-		
66		**Decontamination, Demolition, & Disposal - Removal Of Spent Fuel Systems/Equipment Subtotal**	$ -	$ -	$	$ -	$	$ -	$	$
67										
68		Remove and Dispose of Steam Generators - Unit 2	-	-		-		-		
69		Remove and Dispose of Steam Generators - Unit 3	-	-		-		-		
70		**Decontamination, Demolition, & Disposal - Steam Generator Removal Subtotal**	$ -	$ -	$	$ -	$	$ -	$	$
71										
72		Upgrade Rail Spur	-	-		-	-	-		
73		Remove, Package and Dispose of Non-Essential Systems - Unit 2	-	-		-		-		
74		Remove, Package and Dispose of Non-Essential Systems - Unit 3	-	-		-		-		
75		**Decontamination, Demolition, & Disposal - Non-Essential System Removal Subtotal**	$ -	$ -	$	$ -	$	$ -	$	$
76										
77		Remove, Package and Dispose of Essential Systems	-	-		-		-		
78		Reactor Vessel Insulation Removal and Disposal - Unit 2	-	-		-		-		
79		Segment, Package and Dispose of Reactor Pressure Vessel - Unit 2	-	-		-		-		
80		Reactor Vessel Insulation Removal and Disposal - Unit 3	-	-		-		-		
81		Segment, Package and Dispose of Reactor Pressure Vessel - Unit 3	-	-		-		-		
82		Remove and Dispose of Pressurizer - Unit 2	-	-		-		-		
83		Remove and Dispose of Pressurizer - Unit 3	-	-		-		-		
84		Remove and Dispose of Turbine Gantry Crane - Unit 2	-	-		-		-		
85		Remove and Dispose of Turbine Gantry Crane - Unit 3	-	-		-		-		
86		**Decontamination, Demolition, & Disposal - Large Component Removal Subtotal**	$ -	$ -	$	$ -	$	$ -	$	$
87										
88		Demolish Service Building (K-10, 20, 30)	-	-		-		-		
89		Demolish South Security Processing Facility (K-70)	-	-		-		-		
90		Demolish South Yard Area Buildings T-10, 20, 60 and Haz Mat	-	-		-		-		
91		Procure Clean Building Demolition Equipment	-	-		-		-		
92		Demolish Diesel Generator Building - Unit 3	-	-		-		-		
93		Demolish Diesel Generator Building - Unit 2	-	-		-		-		
94		Demolish Condensate Building and Transformer Pads - Unit 2	-	-		-		-		
95		Demolish Full Flow Area and Turbine Building - Unit 2	-	-		-		-		
96		Demolish AWS Building	-	-		-		-		
97		Demolish Building L-50	-	-		-		-		

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
98	[redacted]	Demolish Maintenance Building 4 (B-64/B-65)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
99	[redacted]	Demolish Maintenance Building 5 (B-62/B-63)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
100	[redacted]	Demolish Outage Control Center	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
101	[redacted]	Demolish Maintenance Building 2 (B-49/B-50)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
102	[redacted]	Demolish Maintenance Building 1 (B-43/B-44)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
103	[redacted]	Demolish Auxiliary Radwaste Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
104	[redacted]	Demolish Auxiliary Control Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
105	[redacted]	Remove Systems and Demolish Make-Up Demineralizer Structures	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
106	[redacted]	Install Concrete Plugs in Intake and Discharge Structures	-	-	[redacted]	-	-	-	[redacted]	[redacted]
107	[redacted]	Demolish Intake and Discharge Structures to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
108	**Decontamination, Demolition, & Disposal - Initial Plant Building Demo Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ 1 [redacted]
109										
110	[redacted]	Decon Containment Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
111	[redacted]	Decon Penetration Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
112	[redacted]	Decon Safety Equipment and MSIV Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
113	[redacted]	Decon Fuel Handling Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
114	[redacted]	Decon Containment Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
115	[redacted]	Decon Penetration Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
116	[redacted]	Decon Safety Equipment and MSIV Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
117	[redacted]	Decon Fuel Handling Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
118	[redacted]	Decon Turbine Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
119	[redacted]	Decon Auxiliary Radwaste Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
120	[redacted]	Decon Auxiliary Control Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
121	**Decontamination, Demolition, & Disposal - Building Decontamination Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ 2 [redacted]
122										
123	[redacted]	Remove Protected Area Pavement	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
124	[redacted]	Demolish Condensate Building and Transformer Pads - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
125	[redacted]	Demolish Full Flow Area and Turbine Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
126	[redacted]	Demolish Unit 3 Fuel Handling Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
127	[redacted]	Demolish Penetration Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
128	[redacted]	Demolish Unit 2 Fuel Handling Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
129	[redacted]	Demolish Penetration Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
130	**Decontamination, Demolition, & Disposal - Final Plant Building Demo Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
131										
132	[redacted]	[2] Offshore Conduit Diffuser and Risers	-	-	[redacted]	-	-	-	[redacted]	[redacted]
133										
134	[redacted]	[2] Backfill	-	-	[redacted]	-	-	-	[redacted]	[redacted]
135										
136	[redacted]	Demolish Staging Warehouse	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
137	[redacted]	Demolish Administration Building (K-40/50)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
138	[redacted]	Detension and Remove Unit 3 Containment Building Tendons	-	-	[redacted]	-	-	-	[redacted]	[redacted]
139	[redacted]	Demolish Safety Equipment and MSIV Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
140	[redacted]	Demolish Unit 3 Containment Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
141	[redacted]	Detension and Remove Unit 2 Containment Building Tendons	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
142	[redacted]	Demolish Safety and MSIV Equipment Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
143	[redacted]	Demolish Unit 2 Containment Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
144	**Decontamination, Demolition, & Disposal - Containment Building Demo Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
145										

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]		Description		Total (Nominal / 2017$) Labor	Material	Cont	Other	Disposal	Overheads	Contingency	Total
146	[redacted]		Prepare License Termination Plan		-	-	[redacted]	-	-	-	[redacted]	[redacted]
147	[redacted]		Final Status Survey		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
148	[redacted]		Subsurface Structure Removal Engineering Planning and Design		-	-	[redacted]	-	-	-	[redacted]	[redacted]
149	**Decontamination, Demolition, & Disposal - Final Survey/License Termination Subtotal**				$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
150												
151	[redacted]	(2)	Waste Taxes (Pass Through)		-	-	-	-	[redacted]	-	[redacted]	[redacted]
152	[redacted]	(2)	Waste Taxes (Pass Through)		-	-	-	-	[redacted]	-	[redacted]	[redacted]
153	**Decontamination, Demolition, & Disposal - Waste Subtotal**				$ -	$ -	$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
154												
155	[redacted]				-	-	[redacted]	-	-	-	[redacted]	[redacted]
156												
157	[redacted]				$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
158												
159	**Other Projects**											
160	SNF-2-D-AM Areva	(2)	Areva ISFSI Relicensing	(7)	-	-	12,550	8	-	-	2,441	14,998
161	SNF-2-D-AM Holtec 1	(2)	Holtec ISFSI I&M Program Development	(7)	-	-	14,892	25	-	3	2,843	17,763
162	SNF-2-D-AM Holtec 2	(2)	Holtec ISFSI Relicensing		-	-	5,000	-	-	-	1,000	6,000
163	**ISFSI Aging Management Subtotal**				**$ -**	**$ -**	**$ 32,441**	**$ 32**	**$ -**	**$ 3**	**$ 6,284**	**$ 38,761**
164												
165	SNF-2-D-EP Holtec	(2)	Environmental Permitting - Holtec		-	-	3,000	-	-	-	600	3,600
166	SNF-2-D-EP Areva	(2)	Environmental Permitting - Areva		-	-	1,650	-	-	-	330	1,980
167	**Coastal Development Permit Extension Subtotal**				**$ -**	**$ -**	**$ 4,650**	**$ -**	**$ -**	**$ -**	**$ 930**	**$ 5,580**
168												
169	SNF-2-D-GTCC	(2)	GTCC Waste Storage		-	-	22,616	-	-	-	5,654	28,270
170												
171	SR-1-D-14 01		Mesa Site Phase I and II Site Assessment and Lease Surrender	(8)	526	-	7,213	25	-	173	1,118	9,054
172	SR-1-D-14 02		Disposition Hazardous Waste from Mesa Site		113	-	10	-	-	73	-	195
173	SR-1-D-14 03		Mesa Site Characterization Survey		15	-	138	(102)	-	10	-	61
174	SR-2-D-15 02		Obtain Required Permits - Mesa	(9)	-	-	55	26	-	1	-	82
175	SR-2-D-15 09		Mesa Buildings - Demo, Maintenance	(10)	258	42	8,783	64	-	99	545	9,791
176	SR-2-D-15 11		Demolish Mesa Roads and Parking Lots		-	396	591	-	-	-	197	1,185
177	SR-2-D-15 12		Finish Grading and Re-vegetate Mesa Site		-	400	304	-	-	-	141	845
178	**Mesa Site Turnover Subtotal**				**$ 911**	**$ 838**	**$ 17,093**	**$ 13**	**$ -**	**$ 356**	**$ 2,001**	**$ 21,212**
179												
180	LT-3-D-DCE	(2)	DCE Update		-	-	2,183	375	-	-	189	2,747
181	SNF-D-DCE	(2)	DCE Update		-	-	1,000	-	-	-	150	1,150
182	**DCE Update Subtotal**				**$ -**	**$ -**	**$ 3,183**	**$ 375**	**$ -**	**$ -**	**$ 339**	**$ 3,897**
183												
184	SR-3-D-16 05		Obtain CEQA Permit & Approvals	(11)	947	16	5,896	327	-	433	712	8,331
185	SR-3-D-16 03		Initial Real Estate Authorization Renewal and Plant Easement	(12)	2,377	-	9,418	640	-	647	2,223	15,305
186	SR-D-NEPA 2	(2)	Plant Lease Extension		1,397	-	1,576	45	-	414	686	4,118
187	SR-D-NEPA 3	(2)	Plant Lease Amendment For Final Site Restoration		1,663	-	5,532	54	-	493	1,548	9,290
188	SNF-D-GTCC Disp	(2)	GTCC Disposal		-	-	36,000	-	-	-	7,200	43,200
189	SNF-2-D-CDP	(2)	ISFSI CDP Settlement		-	-	3,743	800	-	-	-	4,543
190	SR-D-RFP	(2)	Substructure Removal Contractor Procurement		4,741	59	-	-	-	1,406	1,241	7,447
191	SNF-1-D-7 05		Cyber Security Modifications		341	671	8,241	55	-	336	-	9,644
192	SNF-D-NIA Sump	(2)	NIA Sump Modifications		-	-	1,000	-	-	-	150	1,150
193	**Other Projects Subtotal**				**$ 12,377**	**$ 1,583**	**$ 151,389**	**$ 2,341**	**$ -**	**$ 4,088**	**$ 28,969**	**$ 200,748**
194												

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
195	**Substructure Removal**									
196	SR-D-BKFL REM [2]	Backfill Removal	3,358	2,713	-	-	-	996	1,767	8,833
197	SR-5-D-18 02	Install Sheet Piling and Excavation Shoring	-	20,385	10,280	-	-	-	7,666	38,332
198	SR-5-D-18 03	Install Dewatering System and Effluent Treatment and Discharge Controls	-	-	-	29,053	-	-	7,263	36,316
199	SR-5-D-18 04	Demolish and Backfill Unit 3 Condensate Storage Area Below -3 Feet	-	292	207	-	569	-	267	1,334
200	SR-5-D-18 05	Demolish and Backfill Unit 3 Diesel Generator Building Below -3 Feet	-	166	118	-	276	-	140	701
201	SR-5-D-18 06	Demolish and Backfill Unit 3 Fuel Handling Building Below -3 Feet	-	449	344	-	938	-	433	2,163
202	SR-5-D-18 07	Demolish and Backfill Unit 3 Radwaste and Control Building Below -3 Feet	-	1,183	1,062	-	1,819	-	1,016	5,079
203	SR-5-D-18 08	Demolish and Backfill Unit 3 Turbine Building Structure Below 9 Ft Elevation	-	5,374	4,502	-	7,880	-	4,439	22,195
204	SR-5-D-18 09	Demolish and Backfill Unit 3 Safety Equipment Building Below -3 Feet	-	841	828	-	4,120	-	1,447	7,237
205	SR-5-D-18 10	Demolish and Backfill Unit 3 Penetration Area Below -3 Feet	-	394	323	-	801	-	380	1,899
206	SR-5-D-18 11	Demolish and Backfill Unit 3 Full Flow Building Below -3 Feet	-	148	104	-	256	-	127	637
207	SR-5-D-18 12	Demolish and Backfill Unit 3 Containment Building Below -3 Feet	-	1,789	1,358	-	5,048	-	2,049	10,243
208	SR-5-D-18 13	Demolish and Backfill Unit 2 Condensate Storage Area Below -3 Feet	-	292	207	-	569	-	267	1,334
209	SR-5-D-18 14	Demolish and Backfill Unit 2 Diesel Generator Building Below -3 Feet	-	166	118	-	276	-	140	701
210	SR-5-D-18 15	Demolish and Backfill Unit 2 Fuel Handling Building Below -3 Feet	-	449	344	-	938	-	433	2,163
211	SR-5-D-18 16	Demolish and Backfill Unit 2 Radwaste and Control Building Below -3 Feet	-	1,282	1,098	-	1,819	-	1,050	5,249
212	SR-5-D-18 17	Demolish and Backfill Unit 2 Turbine Building Structure Below 9 Ft Elevation	-	5,374	4,502	-	7,881	-	4,439	22,195
213	SR-5-D-18 18	Demolish and Backfill Unit 2 Safety Equipment Building Below -3 Feet	-	841	828	-	4,120	-	1,447	7,237
214	SR-5-D-18 19	Demolish and Backfill Unit 2 Penetration Area Below -3 Feet	-	394	323	-	801	-	380	1,899
215	SR-5-D-18 20	Demolish and Backfill Unit 2 Full Flow Building Below -3 Feet	-	405	248	-	256	-	227	1,137
216	SR-5-D-18 21	Demolish and Backfill Unit 2 Containment Building Below -3 Feet	-	1,786	1,356	-	5,048	-	2,047	10,237
217	SR-5-D-18 22	Demolish and Backfill Intake Structure Below -3 Feet	-	10,418	7,867	-	25,339	-	10,906	54,529
218	SR-5-D-18 24	Remove Sheet Piling and Excavation Shoring	-	-	11,967	-	-	-	2,992	14,958
219	SR-5-D-18 25	Remove Dewatering System and Effluent Treatment	-	-	-	6,947	-	-	1,737	8,684
220	SR-6-D-19 06	Remove and Stockpile Existing Seawall Erosion Protection	-	11	6	-	-	-	4	21
221	SR-6-D-19 07	Remove Unit 2 and 3 Seawall and Pedestrian Walkway	-	3,032	3,258	-	4,606	-	2,724	13,620
222	SR-6-D-19 08	Remove Remaining Intake and Outfall Box Culvert	-	464	341	-	2,211	-	754	3,770
223	SR-6-D-19 10	Backfill and Compaction of Excavation	-	2,217	1,495	-	-	-	928	4,640
224	**Substructure Removal Subtotal**		**$ 3,358**	**$ 60,862**	**$ 53,084**	**$ 36,000**	**$ 75,573**	**$ 996**	**$ 57,468**	**$ 287,340**
225										
226	**Offshore Conduit Removal**									
227	SR-3-D-16 01	Hydrogeologic Investigation and Outfall Conduit Survey	-	130	302	104	-	-	134	670
228	SR-5-D-18 23	Remove Off Shore Intake and Outfall Conduits	-	43,901	12,606	-	19,788	-	19,074	95,369
229	**Offshore Conduit Removal Subtotal**		**$ -**	**$ 44,031**	**$ 12,908**	**$ 104**	**$ 19,788**	**$ -**	**$ 19,208**	**$ 96,039**
230										
231	**ISFSI Demolition**									
232	SNF D&D-1-D-12 01	Preparation and NRC Review of License Termination Plan	-	-	118	161	-	-	70	349
233	SNF D&D-2-D-13 01	Install GARDIAN Bulk Assay System	-	-	-	546	-	-	137	683
234	SNF D&D-2-D-13 02	Decon Areva Modules [13]	-	47	111	-	141	-	75	374
235	SNF D&D-2-D-13 03	Final Status Survey of ISFSI	-	82	520	-	-	-	151	753
236	SNF D&D-2-D-13 04	Clean Demo of Areva ISFSI Pad and Modules [14]	-	1,049	1,923	-	1,270	-	1,060	5,302
237	SNF D&D-2-D-13 05	Demolish ISFSI Security Building [15]	-	266	199	-	528	-	248	1,240
238	SNF D&D-2-D-13 06	Restore ISFSI Site	-	512	346	-	-	-	215	1,073
239	SNF D&D-2-D-13 07	Preparation of Final Report on Decommissioning and NRC Review	-	-	55	-	-	-	14	69
240	SNF D&D-2-D-13 08 [2]	Clean Demo of Holtec ISFSI Pad and Modules	-	1,946	1,452	-	4,910	-	2,077	10,386
241	**ISFSI Demolition Subtotal**		**$ -**	**$ 3,902**	**$ 4,725**	**$ 707**	**$ 6,849**	**$ -**	**$ 4,046**	**$ 20,229**
242										

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
243	**Final Site Restoration**									
244	SR-6-D-19 01	Obtain Required Permits and Approvals	-	20	410	130	-	-	140	700
245	SR-6-D-19 03	Procure Site Restoration Equipment	-	400	-	-	-	-	100	500
246	SR-6-D-19 12	Install Shoreline Erosion Control and Restoration Features	-	142	10	-	-	-	38	190
247	SR-6-D-19 13	Remove Railroad Tracks, Rails and Ballast	-	35	64	-	-	-	25	123
248	SR-6-D-19 14	Remove Gunite Slope Protection	-	362	267	-	1,728	-	589	2,946
249	SR-6-D-19 15	Remove Access Roads and Parking Lots	-	179	244	-	-	-	106	529
250	SR-6-D-19 16	Finish Grading and Re-Vegetate Site	-	834	987	-	-	-	455	2,276
251	**Final Site Restoration Subtotal**		**$ -**	**$ 1,973**	**$ 1,981**	**$ 130**	**$ 1,728**	**$ -**	**$ 1,453**	**$ 7,267**
252										
253	**Distributed Subtotal**									
254										
255	**Labor-Staffing**									
256	LT-U-1 01	Utility Staff	153,426	544	101,384	1,302	-	59,298	16,414	332,367
257	SNF-U-2 01	Utility Staff	196,990	399	39,185	1,045	-	68,546	18,789	324,954
258	SR-U-3 01	Utility Staff	44,437	24	61,492	68	-	11,056	11,423	128,499
259	**Utility Staff Subtotal**		**$ 394,852**	**$ 967**	**$ 202,061**	**$ 2,415**	**$ -**	**$ 138,899**	**$ 46,625**	**$ 785,820**
260										
261	LT-U-1 03	Security Force	11,563	4	146	17	-	2,200	601	14,532
262	SNF-U-2 04	Security Force	163,052	58	2,487	45	-	54,788	12,148	232,580
263	**Security Force Subtotal**		**$ 174,615**	**$ 62**	**$ 2,633**	**$ 63**	**$ -**	**$ 56,989**	**$ 12,749**	**$ 247,112**
264										
265	**Labor-Staffing Subtotal**		**$ 569,468**	**$ 1,029**	**$ 204,694**	**$ 2,478**	**$ -**	**$ 195,888**	**$ 59,375**	**$ 1,032,932**
266										
267	**Non-Labor**									
268	SNF-U-AM Areva	[2] Areva ISFSI Aging Management	-	-	3,713	-	-	-	557	4,270
269	SNF-U-AM Holtec	[2] Holtec ISFSI Aging Management	-	-	10,400	-	-	-	1,560	11,960
270	**Aging Management Subtotal**		**$ -**	**$ -**	**$ 14,113**	**$ -**	**$ -**	**$ -**	**$ 2,117**	**$ 16,230**
271										
272	LT-U-1 17	Association Fees and Expenses	-	3	2,393	2,193	-	9	540	5,138
273	SNF-U-2 26	[2] Association Fees and Expenses	-	-	212	1,838	-	-	307	2,357
274	SR-U-3 17	[2] Association Fees and Expenses	-	-	481	793	-	-	191	1,466
275	**Association Fees and Expenses Subtotal**		**$ -**	**$ 3**	**$ 3,086**	**$ 4,825**	**$ -**	**$ 9**	**$ 1,039**	**$ 8,961**
276										
277	LT-U-1 15	Community Engagement Panel	382	63	2,324	4,285	-	157	679	7,890
278	SNF-U-2 25	[2] Community Engagement Panel	-	-	26	2,440	-	-	370	2,836
279	SR-U-3 21	[2] Community Engagement Panel	-	-	8	1,933	-	-	291	2,232
280	**Community Engagement Panel Subtotal**		**$ 382**	**$ 63**	**$ 2,358**	**$ 8,658**	**$ -**	**$ 157**	**$ 1,340**	**$ 12,958**
281										

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]		Description		Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
282	LT-U-1 08		Contracted Services	(16)	705	9,613	78,768	7,991	-	92	6,641	103,810
283	SNF-U-2 11		Contracted Services	(16)	349	11,718	62,692	18,422	-	165	10,528	103,875
284	SR-U-3 06		Contracted Services	(16)	19	761	21,008	2,452	-	18	3,433	27,690
285	SR-U-Bank	(2)	Bank Fees And Interest		-	-	-	(68)	-	-	-	(68)
286	SR-U-Inv Adj	(2)	Vendor Invoice Adjustment		-	-	-	(213)	-	(1)	-	(214)
287	**Contracted Services Subtotal**				**$ 1,073**	**$ 22,092**	**$ 162,468**	**$ 28,583**	**$ -**	**$ 274**	**$ 20,602**	**$ 235,092**
288												
289	LT-U-1 09		DAW Disposal		-	-	21	-	-	-	-	21
290	SNF-U-2 12		DAW Disposal		-	-	10	-	-	-	-	10
291	**DAW Disposal Subtotal**				**$ -**	**$ -**	**$ 32**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 32**
292												
293	LT-U-1 25		Decommissioning Advisor		-	735	6,854	10	-	25	698	8,322
294	SNF-U-2 28	(2)	Decommissioning Advisor		-	-	292	-	-	-	44	336
295	SR-U-3 22	(2)	Decommissioning Advisor		-	-	1,528	-	-	-	229	1,758
296	**Decommissioning Advisor Subtotal**				**$ -**	**$ 735**	**$ 8,674**	**$ 10**	**$ -**	**$ 25**	**$ 971**	**$ 10,416**
297												
298	LT-U-CO	(2)	DGC Executive Oversight Committee		-	-	2,696	-	-	-	404	3,100
299	SR-U-CO	(2)	DGC Executive Oversight Committee		-	-	746	-	-	-	112	857
300	**DGC Executive Oversight Committee Subtotal**				**$ -**	**$ -**	**$ 3,441**	**$ -**	**$ -**	**$ -**	**$ 516**	**$ 3,958**
301												
302	SNF-U-2 09		Emergency Preparedness Fees		-	22	150	44,615	-	90	5,103	49,980
303	**Emergency Preparedness Fees Subtotal**				**$ -**	**$ 22**	**$ 150**	**$ 44,615**	**$ -**	**$ 90**	**$ 5,103**	**$ 49,980**
304												
305	LT-U-1 10		Energy		-	-	-	46,606	-	137	4,762	51,505
306	SNF-U-2 13		Energy		-	-	-	16,988	-	31	2,036	19,055
307	SR-U-3 07		Energy		-	-	-	14,814	-	-	2,222	17,036
308	**Energy Subtotal**				**$ -**	**$ -**	**$ -**	**$ 78,408**	**$ -**	**$ 168**	**$ 9,020**	**$ 87,596**
309												
310	LT-U-1 24		Environmental Permits and Fees		2	-	344	3,348	-	27	82	3,802
311	SNF-U-2 27	(2)	Environmental Permits and Fees		-	-	676	346	-	-	153	1,176
312	SR-U-3 23	(2)	Environmental Permits and Fees		-	-	193	1,460	-	-	248	1,901
313	**Environmental Permits and Fees Subtotal**				**$ 2**	**$ -**	**$ 1,212**	**$ 5,154**	**$ -**	**$ 27**	**$ 484**	**$ 6,879**
314												
315	SNF-U-GW	(2)	Ground Water Monitoring		-	-	340	-	-	-	51	391
316	SR-U-GW	(2)	Ground Water Monitoring		-	-	120	-	-	-	18	138
317	**Ground Water Monitoring Subtotal**				**$ -**	**$ -**	**$ 460**	**$ -**	**$ -**	**$ -**	**$ 69**	**$ 529**
318												
319	LT-U-1 20		Information Technology	(17)	2,532	1,605	6,001	6,044	-	1,687	1,035	18,905
320	SNF-U-2 20		Information Technology	(17)	-	998	3,730	389	-	-	768	5,885
321	SR-U-3 15		Information Technology	(17)	-	1,670	2,746	649	-	-	760	5,825
322	LT-U-1 21		Telecommunications	(18)	1,275	35	137	88	-	815	-	2,350
323	LT-U-1 22		Personal Computers	(18)	-	9	9	-	-	-	-	18
324	SNF-U-2 22		Personal Computers	(18)	-	7	-	-	-	-	-	7
325	**Information Technology Subtotal**				**$ 3,808**	**$ 4,324**	**$ 12,623**	**$ 7,171**	**$ -**	**$ 2,502**	**$ 2,563**	**$ 32,991**
326												

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
327	LT-U-1 05	Insurance	1	-	-	18,981	-	-	1,090	20,072
328	LT-U-1 14	Workers Compensation Insurance [19]	-	-	-	384	-	-	-	384
329	SNF-U-2 06	Insurance	-	-	-	35,022	-	-	5,030	40,052
330	SR-U-3 04	Insurance	-	-	-	4,533	-	-	680	5,213
331	**Insurance Subtotal**		**$ 1**	**$ -**	**$ -**	**$ 58,921**	**$ -**	**$ -**	**$ 6,800**	**$ 65,722**
332										
333	LT-U-Legal	[2] Third-Party Legal	-	-	8,960	(125)	-	16	1,047	9,899
334	SNF-U-Legal	[2] Third-Party Legal	-	-	9,533	16	-	20	1,119	10,688
335	SR-U-Legal	[2] Third-Party Legal	(836)	-	5,285	6	-	(405)	505	4,555
336	**Third-Party Legal Subtotal**		**$ (836)**	**$ -**	**$ 23,778**	**$ (103)**	**$ -**	**$ (369)**	**$ 2,671**	**$ 25,142**
337										
338	LT-U-1 07	NRC Fees	-	-	4	10,756	-	43	964	11,767
339	SNF-U-2 08	NRC Fees	-	-	30	17,916	-	3	2,574	20,523
340	**NRC Fees Subtotal**		**$ -**	**$ -**	**$ 34**	**$ 28,673**	**$ -**	**$ 46**	**$ 3,538**	**$ 32,291**
341										
342	LT-U-Office	[2] Office Space	-	20	1,000	-	-	-	153	1,173
343	SNF-U-Office	[2] Office Space	-	356	3	-	-	-	54	413
344	SR-U-Office	[2] Office Space	-	104	37	-	-	-	21	162
345	**Office Space Lease Subtotal**		**$ -**	**$ 480**	**$ 1,040**	**$ -**	**$ -**	**$ -**	**$ 228**	**$ 1,748**
346										
347	LT-U-1 04	Security Related Expenses	-	166	216	249	-	2	56	690
348	SNF-U-2 05	Security Related Expenses	1	1,913	6,562	1,305	-	10	1,310	11,102
349	SR-U-3 03	Security Related Expenses	2	124	323	116	-	4	17	586
350	**Security Related Expenses Subtotal**		**$ 4**	**$ 2,203**	**$ 7,101**	**$ 1,671**	**$ -**	**$ 16**	**$ 1,383**	**$ 12,378**
351										
352	SR-U-3 11	Severance	104,551	-	1,816	4,142	-	8,452	4,084	123,044
353	**Severance Subtotal**		**$ 104,551**	**$ -**	**$ 1,816**	**$ 4,142**	**$ -**	**$ 8,452**	**$ 4,084**	**$ 123,044**
354										
355	LT-U-1 06	Site Lease and Easement Expenses	1	-	69	4,102	-	-	350	4,521
356	SNF-U-2 07	Site Lease and Easement Expenses	-	-	-	41,587	-	-	6,238	47,825
357	SR-U-3 05	Site Lease and Easement Expenses	2	-	223	43,225	-	-	5,348	48,798
358	**Site Lease and Easement Expenses Subtotal**		**$ 3**	**$ -**	**$ 292**	**$ 88,914**	**$ -**	**$ -**	**$ 11,936**	**$ 101,145**
359										
360	SNF-U-SFL	[2] Loading Spent Fuel & GTCC Waste To DOE	-	-	28,320	-	-	-	4,248	32,568
361	**Loading Spent Fuel & GTCC Waste To DOE Subtotal**		**$ -**	**$ -**	**$ 28,320**	**$ -**	**$ -**	**$ -**	**$ 4,248**	**$ 32,568**
362										
363	LT-U-1 19	Tools and Equipment	-	-	14	35	-	-	-	49
364	**Tools and Equipment Subtotal**		**$ -**	**$ -**	**$ 14**	**$ 35**	**$ -**	**$ -**	**$ -**	**$ 49**
365										
366	LT-U-1 18	Water [20]	-	-	-	3,890	-	9	436	4,336
367	SNF-U-2 18	Water [20]	-	-	-	8,275	-	6	1,119	9,400
368	SR-U-3 13	Water [20]	-	-	-	2,965	-	-	443	3,408
369	**Water Subtotal**		**$ -**	**$ -**	**$ -**	**$ 15,130**	**$ -**	**$ 15**	**$ 1,998**	**$ 17,143**
370										
371	LT-U-1 02	Utility Staff Health Physics Supplies	-	114	1,012	28	-	8	21	1,183
372	SNF-U-2 02	Utility Staff Health Physics Supplies	-	152	2,305	46	-	13	127	2,643
373	**Utility Staff Health Physics Supplies Subtotal**		**$ -**	**$ 266**	**$ 3,317**	**$ 74**	**$ -**	**$ 21**	**$ 148**	**$ 3,825**
374										
375	**Non-Labor Subtotal**		**$ 108,987**	**$ 30,189**	**$ 274,329**	**$ 374,880**	**$ -**	**$ 11,432**	**$ 80,859**	**$ 880,676**

Appendix C
Table 1
Detailed Cost Table By Cost Type
(Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (Nominal / 2017$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
376										
377	**Service Level Agreements**									
378	LT-U-SLA	[2] Service Level Agreements	32,318	(9)	2,301	30,114	-	9,098	6,278	80,099
379	SNF-U-SLA	[2] Service Level Agreements	7,908	(9)	2,080	9,175	-	25,896	3,521	48,571
380	SR-U-SLA	[2] Service Level Agreements	9,783	(1)	132	8,254	-	26,401	4,403	48,973
381	**Service Level Agreements Subtotal**		**$ 50,010**	**$ (19)**	**$ 4,514**	**$ 47,543**	**$ -**	**$ 61,395**	**$ 14,202**	**$ 177,643**
382										
383	**DGC Staffing**									
384	[redacted]		-	-	[redacted]	-	-	-	[redacted]	[redacted]
385	[redacted]		-	-	[redacted]	-	-	-	[redacted]	[redacted]
386	**Subtotal DGC Staffing**		**$ -**	**$ -**	**$** [redacted]	**$ -**	**$ -**	**$ -**	**$** [redacted]	**$** [redacted]
387										
388	**Undistributed Subtotal**		**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$ -**	**$** [redacted]	**$** [redacted]	**$** [redacted]
389										
390	**Total**		**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description		Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
1	**Completed Projects - 2015 NDCTP**			**$ 1,236**	**$ 2,663**	**$ 88,707**	**$ (134)**	**$ -**	**$ 1,569**	**$ -**	**$ 94,041**
2											
3	LT-2-D-2 18	Planning & Design For Cold and Dark		1,887	1,008	14,875	1,067	-	1,372	-	20,208
4	LT-2-D-2 19	Implement Cold and Dark (Repower Site)		2,083	412	50,494	(458)	-	1,479	-	54,010
5	LT-2-D-2 20	Install 12 kV Service Line to Power Temp Power Ring		1,535	2,746	4,617	413	-	738	-	10,050
6	LT-2-D-2 21	Drain & De-Energize Non-Essential Systems (DEC Process)		2,343	946	1,288	16	-	1,477	-	6,070
7	LT-2-D-2 29	Implement Control Room Modifications (Command Center Relocation)		-	4	332	3	-	3	-	343
8	**Completed Activities - Initial D&D Activities Subtotal**			**$ 7,849**	**$ 5,116**	**$ 71,606**	**$ 1,041**	**$ -**	**$ 5,069**	**$ -**	**$ 90,680**
9											
10	LT-2-D-2 26	Install Spent Fuel Pool System Modifications - Unit 2		136	2,795	1,125	43	-	126	-	4,225
11	LT-2-D-2 27	Install Spent Fuel Pool System Modifications - Unit 3		136	2,795	1,125	43	-	126	-	4,225
12	**Completed Activities - Spent Fuel Islanding Subtotal**			**$ 272**	**$ 5,589**	**$ 2,251**	**$ 85**	**$ -**	**$ 253**	**$ -**	**$ 8,450**
13											
14	LT-2-D-2 07	Prepare Defueled Safety Analysis Report (DSAR)		1	-	1,946	11	-	20	-	1,978
15	**Completed Activities - Phase 2 Regulatory Compliance Subtotal**			**$ 1**	**$ -**	**$ 1,946**	**$ 11**	**$ -**	**$ 20**	**$ -**	**$ 1,978**
16											
17	LT-2-D-2 22	Select Decommissioning General Contractor (DGC)		1,179	7	11,471	406	-	784	-	13,847
18	**Completed Activities - DCG RFP & Prep Subtotal**			**$ 1,179**	**$ 7**	**$ 11,471**	**$ 406**	**$ -**	**$ 784**	**$ -**	**$ 13,847**
19											
20	LT-2-D-LOED	[2] Large Organism Exclusion Device Modification		66	1,054	171	(3)	-	49	-	1,337
21	LT-D-SPV	[2] Special Purpose Vehicle Support		-	-	424	1	-	5	-	430
22	LT-3-D-RecB	[2] Records Backlog		-	-	1,733	183	-	19	-	1,936
23	LT-3-D-S&S	[2] Simplification & Streamlining Project		1	6	1,262	50	-	7	-	1,325
24	**Completed Activities - Transition Modifications Subtotal**			**$ 67**	**$ 1,060**	**$ 3,589**	**$ 230**	**$ -**	**$ 81**	**$ -**	**$ 5,027**
25											
26	**Completed Projects And Activities Subtotal**			**$ 10,603**	**$ 14,435**	**$ 179,568**	**$ 1,640**	**$ -**	**$ 7,776**	**$ -**	**$ 214,024**
27											
28	**ISFSI & Fuel Transfer Operations**										
29	SNF-1-D-7 02	Holtec Long Lead Items and Areva Contract Closure	[3]	95	16,219	30,966	(12,666)	-	438	986	36,039
30	SNF-2-D-8 07	ISFSI Pad Study		-	-	199	2	-	2	-	203
31	SNF-2-D-8 08	Design ISFSI Expansion, Fuel Inspection, and Oversight	[4]	1,219	102	72,413	2,808	-	879	3,450	80,871
32	SNF-2-D-8 09	Construct ISFSI Expansion		92	5	42,362	263	-	170	4,061	46,953
33	SNF-2-D-8 10	Fabrication of Spent Fuel Canisters - Unit 2	[5]	24	1,696	25,947	9,012	-	563	305	37,547
34	SNF-2-D-8 11	Fabrication of Spent Fuel Canisters - Unit 3	[5]	23	1,696	18,782	8,943	-	487	508	30,439
35	SNF-2-D-8 12	Load Fuel Canisters and Fuel Transfer Operations - Unit 2	[6]	-	-	16,574	(1)	-	-	2,505	19,078
36	SNF-2-D-8 13	Load Fuel Canisters and Fuel Transfer Operations - Unit 3	[6]	-	-	16,574	-	-	-	2,505	19,079
37	**ISFSI & Fuel Transfer Operations Subtotal**			**$ 1,453**	**$ 19,719**	**$ 223,817**	**$ 8,362**	**$ -**	**$ 2,540**	**$ 14,321**	**$ 270,210**
38											
39	**Decontamination, Demolition, & Disposal**										
40	[redacted]	Prepare Integrated Work Sequence and Schedule for Decommissioning		-	-	[redacted]	-	-	-	[redacted]	[redacted]
41	[redacted]	Modify Containment Access- Unit 2		-	-	[redacted]	-	-	-	[redacted]	[redacted]
42	[redacted]	Modify Containment Access- Unit 3		-	-	[redacted]	-	-	-	[redacted]	[redacted]
43	[redacted]	Remove and Dispose of Missile Shields - Unit 2		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
44	[redacted]	Remove and Dispose of Reactor Head - Unit 2		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
45	[redacted]	Remove and Dispose of Missile Shields - Unit 3		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
46	[redacted]	Remove and Dispose of Reactor Head - Unit 3		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
47	[redacted]	Prepare Activity Specifications - U2		-	-	[redacted]	-	-	-	[redacted]	[redacted]
48	[redacted]	[2] Waste Contracts		-	-	[redacted]	-	-	-	[redacted]	[redacted]
49	[redacted]	Install GARDIAN System		-	-	[redacted]	-	-	-	[redacted]	[redacted]
50	**Decontamination, Demolition, & Disposal - Initial D&D Activities Subtotal**			**$ -**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ [redacted]**

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
51										
52	[redacted]	Design, Specify, and Procure Special Items and Materials	-	-	[redacted]	-	-	-	[redacted]	[redacted]
53	[redacted]	Test Special Cutting and Handling Equipment and Train Operators	-	-	[redacted]	-	-	-	[redacted]	[redacted]
54	[redacted]	Finalize Internals and Vessel Segmenting Details - Unit 2	-	-	[redacted]	-	-	-	[redacted]	[redacted]
55	[redacted]	Segment, Package and Dispose of Reactor Internals - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
56	[redacted]	Segment, Package and Dispose of Reactor Internals - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
57	**Decontamination, Demolition, & Disposal - Internals and Vessel Segmentation Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
58										
59	[redacted]	Remove Underground Diesel Tank - Unit 2	-	-	[redacted]	-	-	-	[redacted]	[redacted]
60	[redacted]	Remove Underground Diesel Tank - Unit 3	-	-	[redacted]	-	-	-	[redacted]	[redacted]
61	[redacted]	Remove and Dispose of Spent Fuel Storage Racks - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
62	[redacted]	Remove and Dispose of Spent Fuel Storage Racks - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
63	[redacted]	Drain Spent Fuel Pool and Process Liquid Waste - Unit 2	-	-	[redacted]	-	-	-	[redacted]	[redacted]
64	[redacted]	Drain Spent Fuel Pool and Process Liquid Waste - Unit 3	-	-	[redacted]	-	-	-	[redacted]	[redacted]
65	[redacted]	Remove Protected Area Security Fencing	-	-	[redacted]	-	-	-	[redacted]	[redacted]
66	**Decontamination, Demolition, & Disposal - Removal Of Spent Fuel Systems/Equipment Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
67										
68	[redacted]	Remove and Dispose of Steam Generators - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
69	[redacted]	Remove and Dispose of Steam Generators - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
70	**Decontamination, Demolition, & Disposal - Steam Generator Removal Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
71										
72	[redacted]	Upgrade Rail Spur	-	-	[redacted]	-	-	-	[redacted]	[redacted]
73	[redacted]	Remove, Package and Dispose of Non-Essential Systems - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
74	[redacted]	Remove, Package and Dispose of Non-Essential Systems - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
75	**Decontamination, Demolition, & Disposal - Non-Essential System Removal Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
76										
77	[redacted]	Remove, Package and Dispose of Essential Systems	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
78	[redacted]	Reactor Vessel Insulation Removal and Disposal - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
79	[redacted]	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
80	[redacted]	Reactor Vessel Insulation Removal and Disposal - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
81	[redacted]	Segment, Package and Dispose of Reactor Pressure Vessel - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
82	[redacted]	Remove and Dispose of Pressurizer - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
83	[redacted]	Remove and Dispose of Pressurizer - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
84	[redacted]	Remove and Dispose of Turbine Gantry Crane - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
85	[redacted]	Remove and Dispose of Turbine Gantry Crane - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
86	**Decontamination, Demolition, & Disposal - Large Component Removal Subtotal**		$ -	$ -	$ [redacted]	$ -	$ [redacted]	$ -	$ [redacted]	$ [redacted]
87										
88	[redacted]	Demolish Service Building (K-10, 20, 30)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
89	[redacted]	Demolish South Security Processing Facility (K-70)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
90	[redacted]	Demolish South Yard Area Buildings T-10, 20, 60 and Haz Mat	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
91	[redacted]	Procure Clean Building Demolition Equipment	-	-	[redacted]	-	-	-	[redacted]	[redacted]
92	[redacted]	Demolish Diesel Generator Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
93	[redacted]	Demolish Diesel Generator Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
94	[redacted]	Demolish Condensate Building and Transformer Pads - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
95	[redacted]	Demolish Full Flow Area and Turbine Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
96	[redacted]	Demolish AWS Building	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
97	[redacted]	Demolish Building L-50	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
98	[redacted]	Demolish Maintenance Building 4 (B-64/B-65)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
99	[redacted]	Demolish Maintenance Building 5 (B-62/B-63)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
100	[redacted]	Demolish Outage Control Center	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
101	[redacted]	Demolish Maintenance Building 2 (B-49/B-50)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
102	[redacted]	Demolish Maintenance Building 1 (B-43/B-44)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
103	[redacted]	Demolish Auxiliary Radwaste Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
104	[redacted]	Demolish Auxiliary Control Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
105	[redacted]	Remove Systems and Demolish Make-Up Demineralizer Structures	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
106	[redacted]	Install Concrete Plugs in Intake and Discharge Structures	-	-	[redacted]	-	-	-	[redacted]	[redacted]
107	[redacted]	Demolish Intake and Discharge Structures to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
108	**Decontamination, Demolition, & Disposal - Initial Plant Building Demo Subtotal**		$ -	$ -	[redacted]	$ -	[redacted]	$ -	[redacted]	$ [redacted]
109										
110	[redacted]	Decon Containment Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
111	[redacted]	Decon Penetration Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
112	[redacted]	Decon Safety Equipment and MSIV Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
113	[redacted]	Decon Fuel Handling Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
114	[redacted]	Decon Containment Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
115	[redacted]	Decon Penetration Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
116	[redacted]	Decon Safety Equipment and MSIV Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
117	[redacted]	Decon Fuel Handling Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
118	[redacted]	Decon Turbine Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
119	[redacted]	Decon Auxiliary Radwaste Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
120	[redacted]	Decon Auxiliary Control Building - Common	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
121	**Decontamination, Demolition, & Disposal - Building Decontamination Subtotal**		$ -	$ -	[redacted]	$ -	[redacted]	$ -	[redacted]	$ [redacted]
122										
123	[redacted]	Remove Protected Area Pavement	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
124	[redacted]	Demolish Condensate Building and Transformer Pads - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
125	[redacted]	Demolish Full Flow Area and Turbine Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
126	[redacted]	Demolish Unit 3 Fuel Handling Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
127	[redacted]	Demolish Penetration Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
128	[redacted]	Demolish Unit 2 Fuel Handling Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
129	[redacted]	Demolish Penetration Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
130	**Decontamination, Demolition, & Disposal - Final Plant Building Demo Subtotal**		$ -	$ -	[redacted]	$ -	[redacted]	$ -	[redacted]	$ [redacted]
131										
132	[redacted]	[2] Offshore Conduit Diffuser and Risers	-	-	[redacted]	-	-	-	[redacted]	[redacted]
133										
134	[redacted]	[2] Backfill	-	-	[redacted]	-	-	-	[redacted]	[redacted]
135										
136	[redacted]	Demolish Staging Warehouse	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
137	[redacted]	Demolish Administration Building (K-40/50)	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
138	[redacted]	Detension and Remove Unit 3 Containment Building Tendons	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
139	[redacted]	Demolish Safety Equipment and MSIV Building - Unit 3	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
140	[redacted]	Demolish Unit 3 Containment Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
141	[redacted]	Detension and Remove Unit 2 Containment Building Tendons	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
142	[redacted]	Demolish Safety and MSIV Equipment Building - Unit 2	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
143	[redacted]	Demolish Unit 2 Containment Building to 3-Feet Below Grade	-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
144	**Decontamination, Demolition, & Disposal - Containment Building Demo Subtotal**		$ -	$ -	[redacted]	$ -	[redacted]	$ -	[redacted]	$ [redacted]
145										

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]		Description		Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
146	[redacted]		Prepare License Termination Plan		-	-	[redacted]	-	-	-	[redacted]	[redacted]
147	[redacted]		Final Status Survey		-	-	[redacted]	-	[redacted]	-	[redacted]	[redacted]
148	[redacted]		Subsurface Structure Removal Engineering Planning and Design		-	-	[redacted]	-	-	-	[redacted]	[redacted]
149	**Decontamination, Demolition, & Disposal - Final Survey/License Termination Subtotal**				**$ -**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ [redacted]**
150												
151	[redacted]	(2)	Waste Taxes (Pass Through)		-	-	-	-	[redacted]	-	[redacted]	[redacted]
152	[redacted]	(2)	Waste Taxes (Pass Through)		-	-	-	-	[redacted]	-	[redacted]	[redacted]
153	**Decontamination, Demolition, & Disposal - Waste Subtotal**				**$ -**	**$ -**	**$ -**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ [redacted]**
154												
155	[redacted]				-	-	[redacted]	-	-	-	[redacted]	[redacted]
156												
157	**Decontamination, Demolition, & Disposal Subtotal**				**$ -**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ -**	**$ [redacted]**	**$ [redacted]**
158												
159	**Other Projects**											
160	SNF-2-D-AM Areva	(2)	Areva ISFSI Relicensing	(7)	-	-	11,763	7	-	-	2,346	14,117
161	SNF-2-D-AM Holtec 1	(2)	Holtec ISFSI I&M Program Development	(7)	-	-	13,964	24	-	3	2,733	16,724
162	SNF-2-D-AM Holtec 2	(2)	Holtec ISFSI Relicensing		-	-	4,686	-	-	-	961	5,647
163	**ISFSI Aging Management Subtotal**				**$ -**	**$ -**	**$ 30,414**	**$ 32**	**$ -**	**$ 3**	**$ 6,040**	**$ 36,489**
164												
165	SNF-2-D-EP Holtec	(2)	Environmental Permitting - Holtec		-	-	2,812	-	-	-	577	3,388
166	SNF-2-D-EP Areva	(2)	Environmental Permitting - Areva		-	-	1,546	-	-	-	317	1,864
167	**Coastal Development Permit Extension Subtotal**				**$ -**	**$ -**	**$ 4,358**	**$ -**	**$ -**	**$ -**	**$ 894**	**$ 5,252**
168												
169	SNF-2-D-GTCC	(2)	GTCC Waste Storage		-	-	21,197	-	-	-	5,435	26,632
170												
171	SR-1-D-14 01		Mesa Site Phase I and II Site Assessment and Lease Surrender	(8)	494	-	6,784	27	-	163	1,075	8,542
172	SR-1-D-14 02		Disposition Hazardous Waste from Mesa Site		113	-	9	-	-	73	-	195
173	SR-1-D-14 03		Mesa Site Characterization Survey		15	-	133	(102)	-	10	-	56
174	SR-2-D-15 02		Obtain Required Permits - Mesa	(9)	-	-	54	26	-	1	-	81
175	SR-2-D-15 09		Mesa Buildings - Demo, Maintenance	(10)	254	42	8,558	62	-	97	524	9,537
176	SR-2-D-15 11		Demolish Mesa Roads and Parking Lots		-	381	554	-	-	-	190	1,125
177	SR-2-D-15 12		Finish Grading and Re-vegetate Mesa Site		-	385	285	-	-	-	135	805
178	**Mesa Site Turnover Subtotal**				**$ 875**	**$ 807**	**$ 16,377**	**$ 14**	**$ -**	**$ 344**	**$ 1,923**	**$ 20,341**
179												
180	LT-3-D-DCE	(2)	DCE Update		-	-	2,046	360	-	-	181	2,588
181	SNF-D-DCE	(2)	DCE Update		-	-	937	-	-	-	144	1,081
182	**DCE Update Subtotal**				**$ -**	**$ -**	**$ 2,983**	**$ 360**	**$ -**	**$ -**	**$ 326**	**$ 3,669**
183												
184	SR-3-D-16 05		Obtain CEQA Permit & Approvals	(11)	902	15	5,573	325	-	414	685	7,914
185	SR-3-D-16 03		Initial Real Estate Authorization Renewal and Plant Easement	(12)	2,231	-	8,836	616	-	607	2,137	14,427
186	SR-D-NEPA 2	(2)	Plant Lease Extension		1,309	-	1,477	43	-	388	660	3,878
187	SR-D-NEPA 3	(2)	Plant Lease Amendment For Final Site Restoration		1,558	-	5,185	52	-	462	1,488	8,745
188	SNF-D-GTCC Disp	(2)	GTCC Disposal		-	-	33,741	-	-	-	6,921	40,662
189	SNF-2-D-CDP	(2)	ISFSI CDP Settlement		-	-	3,508	769	-	-	-	4,277
190	SR-D-RFP	(2)	Substructure Removal Contractor Procurement		4,444	56	-	-	-	1,318	1,193	7,011
191	SNF-1-D-7 05		Cyber Security Modifications		337	670	7,959	81	-	332	-	9,380
192	SNF-D-NIA Sump	(2)	NIA Sump Modifications		-	-	937	-	-	-	144	1,081
193	**Other Projects Subtotal**				**$ 11,657**	**$ 1,549**	**$ 142,546**	**$ 2,293**	**$ -**	**$ 3,868**	**$ 27,845**	**$ 189,758**
194												

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
195	**Substructure Removal**									
196	SR-D-BKFL REM [2]	Backfill Removal	3,147	2,608	-	-	-	933	1,698	8,386
197	SR-5-D-18 02	Install Sheet Piling and Excavation Shoring	-	19,594	9,635	-	-	-	7,369	36,599
198	SR-5-D-18 03	Install Dewatering System and Effluent Treatment and Discharge Controls	-	-	-	27,926	-	-	6,981	34,907
199	SR-5-D-18 04	Demolish and Backfill Unit 3 Condensate Storage Area Below -3 Feet	-	280	194	-	533	-	256	1,264
200	SR-5-D-18 05	Demolish and Backfill Unit 3 Diesel Generator Building Below -3 Feet	-	159	111	-	259	-	135	664
201	SR-5-D-18 06	Demolish and Backfill Unit 3 Fuel Handling Building Below -3 Feet	-	431	322	-	879	-	416	2,048
202	SR-5-D-18 07	Demolish and Backfill Unit 3 Radwaste and Control Building Below -3 Feet	-	1,137	995	-	1,705	-	976	4,813
203	SR-5-D-18 08	Demolish and Backfill Unit 3 Turbine Building Structure Below 9 Ft Elevation	-	5,165	4,219	-	7,386	-	4,267	21,037
204	SR-5-D-18 09	Demolish and Backfill Unit 3 Safety Equipment Building Below -3 Feet	-	809	776	-	3,861	-	1,391	6,838
205	SR-5-D-18 10	Demolish and Backfill Unit 3 Penetration Area Below -3 Feet	-	379	303	-	751	-	365	1,798
206	SR-5-D-18 11	Demolish and Backfill Unit 3 Full Flow Building Below -3 Feet	-	143	98	-	240	-	122	603
207	SR-5-D-18 12	Demolish and Backfill Unit 3 Containment Building Below -3 Feet	-	1,719	1,272	-	4,731	-	1,969	9,692
208	SR-5-D-18 13	Demolish and Backfill Unit 2 Condensate Storage Area Below -3 Feet	-	280	194	-	533	-	256	1,264
209	SR-5-D-18 14	Demolish and Backfill Unit 2 Diesel Generator Building Below -3 Feet	-	159	111	-	259	-	135	664
210	SR-5-D-18 15	Demolish and Backfill Unit 2 Fuel Handling Building Below -3 Feet	-	431	322	-	879	-	416	2,048
211	SR-5-D-18 16	Demolish and Backfill Unit 2 Radwaste and Control Building Below -3 Feet	-	1,233	1,030	-	1,705	-	1,009	4,976
212	SR-5-D-18 17	Demolish and Backfill Unit 2 Turbine Building Structure Below 9 Ft Elevation	-	5,165	4,219	-	7,386	-	4,267	21,038
213	SR-5-D-18 18	Demolish and Backfill Unit 2 Safety Equipment Building Below -3 Feet	-	809	776	-	3,861	-	1,391	6,838
214	SR-5-D-18 19	Demolish and Backfill Unit 2 Penetration Area Below -3 Feet	-	379	303	-	751	-	365	1,798
215	SR-5-D-18 20	Demolish and Backfill Unit 2 Full Flow Building Below -3 Feet	-	390	232	-	240	-	219	1,081
216	SR-5-D-18 21	Demolish and Backfill Unit 2 Containment Building Below -3 Feet	-	1,716	1,271	-	4,731	-	1,968	9,686
217	SR-5-D-18 22	Demolish and Backfill Intake Structure Below -3 Feet	-	10,013	7,373	-	23,749	-	10,483	51,618
218	SR-5-D-18 24	Remove Sheet Piling and Excavation Shoring	-	-	11,216	-	-	-	2,876	14,091
219	SR-5-D-18 25	Remove Dewatering System and Effluent Treatment	-	-	-	6,678	-	-	1,669	8,347
220	SR-6-D-19 06	Remove and Stockpile Existing Seawall Erosion Protection	-	10	5	-	-	-	4	20
221	SR-6-D-19 07	Remove Unit 2 and 3 Seawall and Pedestrian Walkway	-	2,914	2,826	(38)	4,606	-	2,618	12,927
222	SR-6-D-19 08	Remove Remaining Intake and Outfall Box Culvert	-	446	210	(18)	2,211	-	725	3,574
223	SR-6-D-19 10	Backfill and Compaction of Excavation	-	2,131	1,401	-	-	-	892	4,424
224	**Substructure Removal Subtotal**		**$ 3,147**	**$ 58,501**	**$ 49,416**	**$ 34,547**	**$ 71,258**	**$ 933**	**$ 55,239**	**$ 273,042**
225										
226	**Offshore Conduit Removal**									
227	SR-3-D-16 01	Hydrogeologic Investigation and Outfall Conduit Survey	-	125	283	100	-	-	129	637
228	SR-5-D-18 23	Remove Off Shore Intake and Outfall Conduits	-	42,198	10,838	(163)	19,788	-	18,334	90,995
229	**Offshore Conduit Removal Subtotal**		**$ -**	**$ 42,323**	**$ 11,121**	**$ (63)**	**$ 19,788**	**$ -**	**$ 18,463**	**$ 91,631**
230										
231	**ISFSI Demolition**									
232	SNF D&D-1-D-12 01	Preparation and NRC Review of License Termination Plan	-	-	111	155	-	-	67	333
233	SNF D&D-2-D-13 01	Install GARDIAN Bulk Assay System	-	-	-	525	-	-	131	656
234	SNF D&D-2-D-13 02	Decon Areva Modules [13]	-	45	104	-	136	-	72	357
235	SNF D&D-2-D-13 03	Final Status Survey of ISFSI	-	78	488	-	-	-	145	711
236	SNF D&D-2-D-13 04	Clean Demo of Areva ISFSI Pad and Modules [14]	-	1,009	1,802	-	1,190	-	1,019	5,020
237	SNF D&D-2-D-13 05	Demolish ISFSI Security Building [15]	-	255	186	-	495	-	238	1,174
238	SNF D&D-2-D-13 06	Restore ISFSI Site	-	492	325	-	-	-	206	1,023
239	SNF D&D-2-D-13 07	Preparation of Final Report on Decommissioning and NRC Review	-	-	52	-	-	-	13	65
240	SNF D&D-2-D-13 08 [2]	Clean Demo of Holtec ISFSI Pad and Modules	-	1,871	1,361	-	4,602	-	1,997	9,831
241	**ISFSI Demolition Subtotal**		**$ -**	**$ 3,750**	**$ 4,429**	**$ 680**	**$ 6,423**	**$ -**	**$ 3,889**	**$ 19,171**
242										

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
243	**Final Site Restoration**									
244	SR-6-D-19 01	Obtain Required Permits and Approvals	-	19	384	125	-	-	135	663
245	SR-6-D-19 03	Procure Site Restoration Equipment	-	385	-	-	-	-	96	481
246	SR-6-D-19 12	Install Shoreline Erosion Control and Restoration Features	-	137	9	-	-	-	37	182
247	SR-6-D-19 13	Remove Railroad Tracks, Rails and Ballast	-	33	60	-	-	-	24	116
248	SR-6-D-19 14	Remove Gunite Slope Protection	-	348	164	(14)	1,728	-	566	2,793
249	SR-6-D-19 15	Remove Access Roads and Parking Lots	-	173	229	-	-	-	102	503
250	SR-6-D-19 16	Finish Grading and Re-Vegetate Site	-	801	925	-	-	-	438	2,164
251	**Final Site Restoration Subtotal**		**$ -**	**$ 1,897**	**$ 1,772**	**$ 111**	**$ 1,728**	**$ -**	**$ 1,397**	**$ 6,905**
252										
253	**Distributed Subtotal**									
254										
255	**Labor-Staffing**									
256	LT-U-1 01	Utility Staff	147,700	538	95,923	1,316	-	57,551	15,777	318,805
257	SNF-U-2 01	Utility Staff	187,798	394	37,206	1,074	-	65,874	18,060	310,406
258	SR-U-3 01	Utility Staff	41,681	24	57,641	66	-	10,379	10,980	120,770
259	**Utility Staff Subtotal**		**$ 377,179**	**$ 956**	**$ 190,770**	**$ 2,457**	**$ -**	**$ 133,803**	**$ 44,817**	**$ 749,981**
260										
261	LT-U-1 03	Security Force	11,010	4	138	18	-	2,128	577	13,875
262	SNF-U-2 04	Security Force	155,557	58	2,344	45	-	52,636	11,677	222,317
263	**Security Force Subtotal**		**$ 166,567**	**$ 61**	**$ 2,482**	**$ 63**	**$ -**	**$ 54,764**	**$ 12,255**	**$ 236,192**
264										
265	**Labor-Staffing Subtotal**		**$ 543,746**	**$ 1,017**	**$ 193,252**	**$ 2,519**	**$ -**	**$ 188,567**	**$ 57,071**	**$ 986,172**
266										
267	**Non-Labor**									
268	SNF-U-AM Areva	[2] Areva ISFSI Aging Management	-	-	3,480	-	-	-	535	4,015
269	SNF-U-AM Holtec	[2] Holtec ISFSI Aging Management	-	-	9,747	-	-	-	1,499	11,247
270	**Aging Management Subtotal**		**$ -**	**$ -**	**$ 13,227**	**$ -**	**$ -**	**$ -**	**$ 2,035**	**$ 15,262**
271										
272	LT-U-1 17	Association Fees and Expenses	-	3	2,253	2,122	-	8	519	4,906
273	SNF-U-2 26	[2] Association Fees and Expenses	-	-	198	1,767	-	-	296	2,261
274	SR-U-3 17	[2] Association Fees and Expenses	-	-	451	762	-	-	184	1,397
275	**Association Fees and Expenses Subtotal**		**$ -**	**$ 3**	**$ 2,903**	**$ 4,651**	**$ -**	**$ 8**	**$ 999**	**$ 8,564**
276										
277	LT-U-1 15	Community Engagement Panel	382	63	2,234	4,128	-	156	653	7,615
278	SNF-U-2 25	[2] Community Engagement Panel	-	-	24	2,345	-	-	356	2,725
279	SR-U-3 21	[2] Community Engagement Panel	-	-	7	1,858	-	-	280	2,145
280	**Community Engagement Panel Subtotal**		**$ 382**	**$ 63**	**$ 2,265**	**$ 8,332**	**$ -**	**$ 156**	**$ 1,288**	**$ 12,486**
281										

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]		Description		Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
282	LT-U-1 08		Contracted Services	(16)	684	9,499	75,723	7,883	-	75	6,383	100,247
283	SNF-U-2 11		Contracted Services	(16)	340	11,309	59,271	17,865	-	155	10,120	99,060
284	SR-U-3 06		Contracted Services	(16)	18	732	19,705	2,361	-	17	3,300	26,134
285	SR-U-Bank	(2)	Bank Fees And Interest		-	-	-	(67)	-	-	-	(67)
286	SR-U-Inv Adj	(2)	Vendor Invoice Adjustment		-	-	-	(209)	-	(1)	-	(210)
287	**Contracted Services Subtotal**				**$ 1,042**	**$ 21,540**	**$ 154,700**	**$ 27,833**	**$ -**	**$ 247**	**$ 19,803**	**$ 225,164**
288												
289	LT-U-1 09		DAW Disposal		-	-	20	-	-	-	-	20
290	SNF-U-2 12		DAW Disposal		-	-	10	-	-	-	-	10
291	**DAW Disposal Subtotal**				**$ -**	**$ -**	**$ 30**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 30**
292												
293	LT-U-1 25		Decommissioning Advisor		-	730	6,487	16	-	25	671	7,930
294	SNF-U-2 28	(2)	Decommissioning Advisor		-	-	274	-	-	-	42	316
295	SR-U-3 22	(2)	Decommissioning Advisor		-	-	1,432	-	-	-	220	1,653
296	**Decommissioning Advisor Subtotal**				**$ -**	**$ 730**	**$ 8,193**	**$ 16**	**$ -**	**$ 25**	**$ 934**	**$ 9,899**
297												
298	LT-U-CO	(2)	DGC Executive Oversight Committee		-	-	2,527	-	-	-	389	2,915
299	SR-U-CO	(2)	DGC Executive Oversight Committee		-	-	699	-	-	-	107	806
300	**DGC Executive Oversight Committee Subtotal**				**$ -**	**$ -**	**$ 3,225**	**$ -**	**$ -**	**$ -**	**$ 496**	**$ 3,722**
301												
302	SNF-U-2 09		Emergency Preparedness Fees		-	22	144	43,181	-	89	4,905	48,341
303	**Emergency Preparedness Fees Subtotal**				**$ -**	**$ 22**	**$ 144**	**$ 43,181**	**$ -**	**$ 89**	**$ 4,905**	**$ 48,341**
304												
305	LT-U-1 10		Energy		-	-	-	45,237	-	134	4,577	49,948
306	SNF-U-2 13		Energy		-	-	-	16,421	-	30	1,957	18,409
307	SR-U-3 07		Energy		-	-	-	14,239	-	-	2,136	16,375
308	**Energy Subtotal**				**$ -**	**$ -**	**$ -**	**$ 75,897**	**$ -**	**$ 164**	**$ 8,670**	**$ 84,732**
309												
310	LT-U-1 24		Environmental Permits and Fees		2	-	334	3,317	-	26	79	3,758
311	SNF-U-2 27	(2)	Environmental Permits and Fees		-	-	633	333	-	-	147	1,114
312	SR-U-3 23	(2)	Environmental Permits and Fees		-	-	181	1,403	-	-	238	1,822
313	**Environmental Permits and Fees Subtotal**				**$ 2**	**$ -**	**$ 1,149**	**$ 5,053**	**$ -**	**$ 26**	**$ 465**	**$ 6,695**
314												
315	SNF-U-GW	(2)	Ground Water Monitoring		-	-	319	-	-	-	49	368
316	SR-U-GW	(2)	Ground Water Monitoring		-	-	112	-	-	-	17	130
317	**Ground Water Monitoring Subtotal**				**$ -**	**$ -**	**$ 431**	**$ -**	**$ -**	**$ -**	**$ 66**	**$ 497**
318												
319	LT-U-1 20		Information Technology	(17)	2,524	1,547	5,684	5,993	-	1,680	995	18,424
320	SNF-U-2 20		Information Technology	(17)	-	960	3,496	374	-	-	738	5,568
321	SR-U-3 15		Information Technology	(17)	-	1,605	2,574	624	-	-	730	5,533
322	LT-U-1 21		Telecommunications	(18)	1,275	35	137	88	-	815	-	2,350
323	LT-U-1 22		Personal Computers	(18)	-	9	9	-	-	-	-	18
324	SNF-U-2 22		Personal Computers	(18)	-	7	-	-	-	-	-	7
325	**Information Technology Subtotal**				**$ 3,799**	**$ 4,163**	**$ 11,900**	**$ 7,080**	**$ -**	**$ 2,496**	**$ 2,463**	**$ 31,900**
326												

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
327	LT-U-1 05	Insurance	1	-	-	18,675	-	-	1,048	19,723
328	LT-U-1 14	Workers Compensation Insurance [19]	-	-	-	381	-	-	-	381
329	SNF-U-2 06	Insurance	-	-	-	33,712	-	-	4,835	38,547
330	SR-U-3 04	Insurance	-	-	-	4,358	-	-	654	5,011
331	**Insurance Subtotal**		**$ 1**	**$ -**	**$ -**	**$ 57,126**	**$ -**	**$ -**	**$ 6,536**	**$ 63,663**
332										
333	LT-U-Legal	[2] Third-Party Legal	-	-	8,460	(122)	-	16	1,006	9,359
334	SNF-U-Legal	[2] Third-Party Legal	-	-	9,013	15	-	19	1,076	10,123
335	SR-U-Legal	[2] Third-Party Legal	(802)	-	5,013	7	-	(389)	486	4,315
336	**Third-Party Legal Subtotal**		**$ (802)**	**$ -**	**$ 22,486**	**$ (100)**	**$ -**	**$ (353)**	**$ 2,568**	**$ 23,799**
337										
338	LT-U-1 07	NRC Fees	-	-	4	10,480	-	42	927	11,452
339	SNF-U-2 08	NRC Fees	-	-	28	17,229	-	3	2,474	19,735
340	**NRC Fees Subtotal**		**$ -**	**$ -**	**$ 32**	**$ 27,709**	**$ -**	**$ 45**	**$ 3,401**	**$ 31,187**
341										
342	LT-U-Office	[2] Office Space	-	19	937	-	-	-	147	1,104
343	SNF-U-Office	[2] Office Space	-	343	3	-	-	-	52	397
344	SR-U-Office	[2] Office Space	-	100	35	-	-	-	20	154
345	**Office Space Lease Subtotal**		**$ -**	**$ 461**	**$ 975**	**$ -**	**$ -**	**$ -**	**$ 219**	**$ 1,655**
346										
347	LT-U-1 04	Security Related Expenses	-	160	205	245	-	2	54	667
348	SNF-U-2 05	Security Related Expenses	1	1,847	6,180	1,261	-	10	1,259	10,559
349	SR-U-3 03	Security Related Expenses	2	121	309	114	-	4	16	566
350	**Security Related Expenses Subtotal**		**$ 4**	**$ 2,129**	**$ 6,694**	**$ 1,620**	**$ -**	**$ 16**	**$ 1,329**	**$ 11,792**
351										
352	SR-U-3 11	Severance	102,979	-	1,796	4,018	-	8,329	3,925	121,047
353	**Severance Subtotal**		**$ 102,979**	**$ -**	**$ 1,796**	**$ 4,018**	**$ -**	**$ 8,329**	**$ 3,925**	**$ 121,047**
354										
355	LT-U-1 06	Site Lease and Easement Expenses	1	-	68	3,996	-	-	336	4,401
356	SNF-U-2 07	Site Lease and Easement Expenses	-	-	-	39,974	-	-	5,996	45,970
357	SR-U-3 05	Site Lease and Easement Expenses	2	-	218	41,749	-	-	5,141	47,110
358	**Site Lease and Easement Expenses Subtotal**		**$ 3**	**$ -**	**$ 286**	**$ 85,719**	**$ -**	**$ -**	**$ 11,473**	**$ 97,481**
359										
360	SNF-U-SFL	[2] Loading Spent Fuel & GTCC Waste To DOE	-	-	26,543	-	-	-	4,083	30,626
361	**Loading Spent Fuel & GTCC Waste To DOE Subtotal**		**$ -**	**$ -**	**$ 26,543**	**$ -**	**$ -**	**$ -**	**$ 4,083**	**$ 30,626**
362										
363	LT-U-1 19	Tools and Equipment	-	-	14	34	-	-	-	49
364	**Tools and Equipment Subtotal**		**$ -**	**$ -**	**$ 14**	**$ 34**	**$ -**	**$ -**	**$ -**	**$ 49**
365										
366	LT-U-1 18	Water [20]	-	-	-	3,773	-	9	419	4,201
367	SNF-U-2 18	Water [20]	-	-	-	7,975	-	6	1,076	9,056
368	SR-U-3 13	Water [20]	-	-	-	2,850	-	-	426	3,276
369	**Water Subtotal**		**$ -**	**$ -**	**$ -**	**$ 14,598**	**$ -**	**$ 15**	**$ 1,921**	**$ 16,534**
370										
371	LT-U-1 02	Utility Staff Health Physics Supplies	-	113	970	28	-	8	20	1,139
372	SNF-U-2 02	Utility Staff Health Physics Supplies	-	150	2,192	47	-	12	122	2,524
373	**Utility Staff Health Physics Supplies Subtotal**		**$ -**	**$ 263**	**$ 3,162**	**$ 75**	**$ -**	**$ 20**	**$ 142**	**$ 3,663**
374										
375	**Non-Labor Subtotal**		**$ 107,408**	**$ 29,374**	**$ 260,155**	**$ 362,842**	**$ -**	**$ 11,283**	**$ 77,722**	**$ 848,786**

Appendix C
Table 2
Detailed Cost Table By Cost Type
(2014 Dollars In Thousands, 100% Share)

	DCE No.[1]	Description	Total (2014$) Labor	Material	Contract	Other	Disposal	Overheads	Contingency	Total
376										
377	**Service Level Agreements**									
378	LT-U-SLA	[2] Service Level Agreements	30,319	(9)	2,204	28,976	-	8,542	6,034	76,066
379	SNF-U-SLA	[2] Service Level Agreements	7,435	(8)	1,993	8,847	-	24,284	3,385	45,935
380	SR-U-SLA	[2] Service Level Agreements	9,171	-	127	7,936	-	24,745	4,232	46,211
381	**Service Level Agreements Subtotal**		**$ 46,925**	**$ (17)**	**$ 4,324**	**$ 45,759**	**$ -**	**$ 57,571**	**$ 13,651**	**$ 168,212**
382										
383	**DGC Staffing**									
384	[redacted]		-	-	[redacted]	-	-	-	[redacted]	[redacted]
385	[redacted]		-	-	[redacted]	-	-	-	[redacted]	[redacted]
386	**Subtotal DGC Staffing**		**$ -**	**$ -**	**$** [redacted]	**$ -**	**$ -**	**$ -**	**$** [redacted]	**$** [redacted]
387										
388	**Undistributed Subtotal**		**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$ -**	**$** [redacted]	**$** [redacted]	**$** [redacted]
389										
390	**Total**		**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]	**$** [redacted]

Notes To Appendix C

Notes:

(1) The DCE line numbers align to the line numbers in Appendix D of the 2014 DCE. The DCE line numbers indicate the corresponding 2014 DCE (1) NRC cost account, (2) 2014 DCE period, (3) cost type (i.e., distributed or undistributed), and (4) line number. For example, "LT-2-D-2.17" in Appendix C of this DCE corresponds to License Termination Period 2 distributed cost line number 2.17 in Appendix D of the 2014 DCE.

(2) These line items were not included in the 2014 DCE, and therefore a new DCE No. has been created.

(3) The description for DCE line number SNF-1-D-7.02 in the 2014 DCE of "Design and Fabricate Spent Fuel Canisters" has been updated to "Holtec Long Lead Items and Areva Contract Closure" to better reflect the associated costs.

(4) The description for DCE line number SNF-2-D-8.08 in the 2014 DCE of "Design ISFSI Expansion" has been updated to "Design ISFSI Expansion, Fuel Inspection, and Oversight" to better reflect the associated costs.

(5) The description for DCE line numbers SNF-2-D-8.10 and SNF-2-D-8.11 in the 2014 DCE of "Purchase and Fabrication of Spent Fuel Canisters and AHSMs" for Units 2 & 3, respectively, have been updated to "Fabrication of Spent Fuel Canisters" to better reflect the associated costs.

(6) The description for DCE line numbers SNF-2-D-8.12 and SNF-2-D-8.13 in the 2014 DCE of "Deliver and Load Spent Fuel Canisters and Transfer to ISFSI" for Units 2 & 3, respectively, have been updated to "Load Fuel Canisters and Fuel Transfer Operations" to better reflect the associated costs.

(7) In Advice Letter 3589-E, Aging Management recorded costs were included in DCE No. SNF-2-D-AM. In the 2017 DCE, Areva and Holtec Aging Management costs are estimated separately, and therefore the Areva and Holtec recorded costs are also shown separately and are included in DCE Nos. SNF-2-D-AM Areva and SNF-2-D-AM Holtec 1.

(8) The description for DCE line number SR-1-D-14.01 in the 2014 DCE of "Mesa Site Phase I and II Site Assessment" has been updated to "Mesa Site Phase I and II Site Assessment and Lease Surrender" to better reflect the associated costs.

(9) The description for DCE line number SR-2-D-15.02 in the 2014 DCE of "Obtain Required Permits For Mesa, South Access and South Yard" has been updated to "Obtain Required Permits - Mesa" to better reflect the associated costs.

(10) The description for DCE line number SR-2-D-15.09 in the 2014 DCE of "Demolish Mesa Buildings" has been updated to "Mesa Buildings - Demo, Maintenance" to better reflect the associated costs.

(11) The description for DCE line number SR-3-D-16.05 in the 2014 DCE of "Obtain Required Permits and Approvals" has been updated to "Obtain CEQA Permit & Approvals" to better reflect the associated costs.

(12) The description for DCE line number SR-3-D-16.03 in the 2014 DCE of "Environmental Impacts Analyses for Lease Termination Activities" has been updated to "Initial Real Estate Authorization Renewal and Plant Easement" to better reflect the associated costs.

(13) The description for DCE line number SNF D&D-2-D-13.02 in the 2014 DCE of "Decon AHSMs" has been updated to "Decon Areva Modules" to better reflect the associated costs.

(14) The description for DCE line number SNF D&D-2-D-13.04 in the 2014 DCE of "Clean Demolition of ISFSI AHSMs and Pad" has been updated to "Clean Demo of Areva ISFSI Pad and Modules" to better reflect the associated costs.

(15) The description for DCE line number SNF D&D-2-D-13.05 in the 2014 DCE of "Clean Demolition of ISFSI Support Structures" has been updated to "Demolish ISFSI Security Building" to better reflect the associated costs.

Notes To Appendix C

(16) The description for DCE line numbers LT-U-1.08, SNF-U-2.11, and SR-U-3.06 in the 2014 DCE of "Materials and Services" has been updated to "Contracted Services" to better reflect the associated costs.

(17) The description for DCE line numbers LT-U-1.20, SNF-U-2.20, and SR-U-3.15 in the 2014 DCE of "Non-Process Computers" has been updated to "Information Technology" to better reflect the associated costs.

(18) All estimated (i.e., 2017-2051) undistributed Information Technology costs that are not covered by the IT Service Level Agreement are captured in DCE line items LT-U-1.20, SNF-U-2.20, and SR-U-3.15, "Information Technology," and therefore DCE line items LT-U-1.21, LT-U-1.22, and SNF-U-2.22 for Telecommunications and Personal Computers do not include any estimated costs.

(19) Estimated costs (i.e., 2017-2051) for workers compensation insurance are included in DCE line items LT-U-1.05, SNF-U-2.06, and SR-U-3.04, "Insurance."

(20) The description for DCE line numbers LT-U-1.18, SNF-U-2.18, and SR-U-3.13 in the 2014 DCE of "Utilities (Water, Gas, Phone)" has been updated to "Water" to better reflect the associated costs.

(21) The undistributed DGC staffing costs associated with the fixed price contract are included in the distributed project for Decontamination, Demolition, & Disposal.

Appendix D

Annual Cash Flow Tables By NRC Cost Category

Appendix D
Table 1-A
Annual Cash Flow Table By NRC Cost Category - Unit 2

Nominal / 2017 Dollars in Thousands

Period	Year	License Termination	Spent Fuel Management	Site Restoration	Total
Pd 1 - Initial Activities	2013	$ 40,388	$ 40,591	$ 40,988	$ 121,967
	2014	56,443	39,579	12,731	108,753
	2015	63,557	55,132	25,520	144,209
	2016	43,464	62,700	1,044	107,208
Pd 2 -Transition & Pool Storage	2017	104,155	67,490	4,667	176,313
	2018	61,943	68,965	3,710	134,618
Pd 3					
Pd 4 - D&D and Dry Storage	2019	49,280	27,254	9,911	86,445
	2020	58,306	15,799	1,847	75,951
	2021	141,012	8,718	2,240	151,971
	2022	153,239	8,077	22,202	183,517
	2023	65,533	5,536	52,406	123,475
	2024	40,938	5,423	32,450	78,811
	2025	31,276	5,344	24,942	61,562
	2026	60,901	5,747	15,901	82,548
	2027	17,045	5,536	41,145	63,726
	2028	19,853	5,678	1,871	27,402
Pd 5 - Dry Storage	2029	-	9,883	1,241	11,124
	2030	-	9,842	-	9,842
	2031	-	10,224	20	10,244
	2032	-	10,528	24	10,552
	2033	-	12,192	18	12,209
	2034	-	12,170	18	12,187
	2035	-	13,401	20	13,422
	2036	-	12,628	-	12,628
	2037	-	11,127	-	11,127
	2038	-	10,971	-	10,971
	2039	-	11,445	-	11,445
	2040	-	11,363	68	11,431
	2041	-	10,905	45	10,950
	2042	-	11,626	43	11,669
	2043	-	11,629	27	11,656
	2044	-	11,041	4,317	15,359
	2045	-	10,440	4,308	14,748
Pd 6 - Civil Works Project	2046	-	8,600	29,378	37,977
	2047	-	7,150	76,564	83,714
	2048	-	8,454	62,150	70,604
	2049	-	35,143	14,931	50,074
Pd 7 - ISFSI Demolition & Final Site Restoration	2050	-	12,763	12,744	25,507
	2051	-	6,125	23,682	29,807
	Total	**$ 1,007,333**	**$ 697,217**	**$ 523,173**	**$ 2,227,722**

Appendix D
Table 1-B
Annual Cash Flow Table By NRC Cost Category - Unit 3

Nominal / 2017 Dollars in Thousands

Period	Year	License Termination	Spent Fuel Management	Site Restoration	Total
Pd 1 - Initial Activities	2013	$ 40,388	$ 40,161	$ 40,988	$ 121,538
	2014	56,270	39,421	12,731	108,422
	2015	63,601	47,813	27,164	138,577
	2016	43,688	65,477	5,157	114,322
Pd 2 -Transition & Pool Storage	2017	99,851	69,885	15,574	185,310
	2018	62,289	70,530	11,543	144,362
Pd 3					
Pd 4 - D&D and Dry Storage	2019	52,448	28,927	16,145	97,520
	2020	76,967	17,443	5,994	100,404
	2021	122,673	10,562	8,131	141,366
	2022	118,848	9,931	27,672	156,451
	2023	65,340	7,406	55,726	128,472
	2024	46,564	7,293	39,281	93,137
	2025	53,899	7,214	37,747	98,860
	2026	51,797	6,684	23,721	82,202
	2027	23,351	6,473	40,386	70,210
	2028	19,859	6,615	1,895	28,369
Pd 5 - Dry Storage	2029	-	10,908	1,241	12,150
	2030	-	10,811	-	10,811
	2031	-	11,192	834	12,027
	2032	-	11,568	1,011	12,579
	2033	-	13,203	749	13,952
	2034	-	13,174	757	13,930
	2035	-	14,552	867	15,420
	2036	-	13,700	-	13,700
	2037	-	12,199	-	12,199
	2038	-	12,100	-	12,100
	2039	-	12,517	-	12,517
	2040	-	12,435	2,879	15,314
	2041	-	12,034	1,916	13,950
	2042	-	12,698	1,804	14,502
	2043	-	12,701	1,123	13,824
	2044	-	12,688	9,105	21,794
	2045	-	11,972	8,718	20,690
Pd 6 - Civil Works Project	2046	-	9,654	29,648	39,302
	2047	-	8,492	76,834	85,326
	2048	-	9,508	61,774	71,282
	2049	-	36,198	34,134	70,331
Pd 7 - ISFSI Demolition & Final Site Restoration	2050	-	12,763	66,431	79,194
	2051	-	6,125	72,005	78,130
	Total	**$ 997,833**	**$ 735,025**	**$ 741,683**	**$ 2,474,542**

Appendix D
Table 2-A
Annual Cash Flow Table By NRC Cost Category - Unit 2

2014 Dollars in Thousands

Period	Year	License Termination	Spent Fuel Management	Site Restoration	Total
Pd 1 - Initial Activities	2013	$ 40,388	$ 40,591	$ 40,988	$ 121,967
	2014	56,443	39,579	12,731	108,753
	2015	62,388	54,147	25,017	141,552
	2016	41,851	60,067	1,026	102,945
Pd 2 -Transition & Pool Storage	2017	97,798	63,427	4,397	165,622
	2018	58,415	64,919	3,512	126,845
Pd 3					
Pd 4 - D&D and Dry Storage	2019	46,449	25,691	9,376	81,515
	2020	54,947	14,904	1,767	71,617
	2021	132,808	8,224	2,138	143,170
	2022	144,304	7,618	20,915	172,837
	2023	61,728	5,225	49,370	116,323
	2024	38,580	5,120	30,609	74,309
	2025	29,487	5,044	23,539	58,070
	2026	57,385	5,423	15,014	77,822
	2027	16,089	5,226	38,808	60,123
	2028	18,764	5,358	1,787	25,909
Pd 5 - Dry Storage	2029	-	9,361	1,170	10,531
	2030	-	9,325	-	9,325
	2031	-	9,680	19	9,698
	2032	-	9,965	22	9,988
	2033	-	11,534	17	11,550
	2034	-	11,513	17	11,529
	2035	-	12,671	19	12,691
	2036	-	11,946	-	11,946
	2037	-	10,530	-	10,530
	2038	-	10,383	-	10,383
	2039	-	10,835	-	10,835
	2040	-	10,754	64	10,818
	2041	-	10,323	43	10,365
	2042	-	11,004	40	11,044
	2043	-	11,003	25	11,028
	2044	-	10,452	4,057	14,510
	2045	-	9,889	4,049	13,938
Pd 6 - Civil Works Project	2046	-	8,106	27,855	35,962
	2047	-	6,743	72,797	79,540
	2048	-	7,972	58,788	66,760
	2049	-	33,100	14,123	47,223
Pd 7 - ISFSI Demolition & Final Site Restoration	2050	-	12,071	12,050	24,121
	2051	-	5,804	22,433	28,238
	Total	**$ 957,823**	**$ 665,525**	**$ 498,584**	**$ 2,121,932**

Appendix D
Table 2-B
Annual Cash Flow Table By NRC Cost Category - Unit 3

2014 Dollars in Thousands

Period	Year	License Termination	Spent Fuel Management	Site Restoration	Total
Pd 1 - Initial Activities	2013	$ 40,388	$ 40,161	$ 40,988	$ 121,538
	2014	56,270	39,421	12,731	108,422
	2015	62,436	46,872	26,631	135,939
	2016	42,075	63,001	4,981	110,057
Pd 2 -Transition & Pool Storage	2017	93,754	65,719	14,650	174,122
	2018	58,747	66,431	10,886	136,065
Pd 3					
Pd 4 - D&D and Dry Storage	2019	49,431	27,304	15,243	91,978
	2020	72,511	16,489	5,671	94,671
	2021	115,546	9,997	7,703	133,246
	2022	111,934	9,400	26,065	147,399
	2023	61,546	7,022	52,495	121,063
	2024	43,875	6,917	37,039	87,831
	2025	50,781	6,841	35,592	93,213
	2026	48,817	6,323	22,375	77,514
	2027	22,025	6,126	38,094	66,245
	2028	18,770	6,258	1,810	26,839
Pd 5 - Dry Storage	2029	-	10,345	1,170	11,515
	2030	-	10,255	-	10,255
	2031	-	10,610	786	11,396
	2032	-	10,963	952	11,916
	2033	-	12,505	705	13,210
	2034	-	12,477	712	13,189
	2035	-	13,776	816	14,592
	2036	-	12,976	-	12,976
	2037	-	11,560	-	11,560
	2038	-	11,467	-	11,467
	2039	-	11,865	-	11,865
	2040	-	11,784	2,710	14,494
	2041	-	11,407	1,803	13,210
	2042	-	12,034	1,698	13,732
	2043	-	12,033	1,057	13,090
	2044	-	12,023	8,565	20,588
	2045	-	11,351	8,201	19,552
Pd 6 - Civil Works Project	2046	-	9,120	28,115	37,235
	2047	-	8,027	73,056	81,083
	2048	-	8,986	58,430	67,416
	2049	-	34,114	32,373	66,487
Pd 7 - ISFSI Demolition & Final Site Restoration	2050	-	12,071	63,258	75,328
	2051	-	5,804	68,532	74,336
	Total	**$ 948,906**	**$ 701,836**	**$ 705,892**	**$ 2,356,634**

Appendix E

Share Of Liability For SONGS Participants

Appendix E
Share Of Liability For SONGS Participants

Cost Categories	SDG&E	Riverside	Anaheim	SCE
SONGS 1	20%	0%	0%	80%
SONGS 2	20%	1.79%	2.4737%	75.7363%
SONGS 3	20%	1.79%	2.4625%	75.4775%
Common Facilities (Units 2 & 3)	20%	1.79%	2.4681%	75.7419%
SONGS 1 Fuel	20%	0%	0%	80%
SONGS 2/3 Fuel	20%	1.79%	2.3398%	75.8702%
ISFSI Maintenance and D&D	20%	1.6066%	2.2686%	76.1248%
San Diego Switchyard	100%	0%	0%	0%
Edison Switchyard	0%	0%	0%	100%
Interconnection Facilities	50%	0%	0%	50%
Nuclear Fuel Cancellation Charges	20%	1.79%	0%	78.21%

Note:
SDG&E, Riverside, and Anaheim incur additional costs related to oversight activities that are not included in the 2017 DCE.

Appendix C

Reconciliation - Confidential

Southern California Edison
SONGS 2&3 2017 Decommissioning Cost Estimate
Reconciliation Of Kenrich 2017 SONGS 2&3 DCE To SCE Testimony
(2014 Dollars In Millions, 100% Share)

	Description	2017 DCE Kenrich Report (2014 $)	Adjustments (2014 $) DGC Staffing Adjustment	Cold & Dark Adjustment	Non-Labor Adjustment	Other Projects Adjustment	2017 DCE SCE Testimony (2014 $)
1	**Distributed Projects**						
2	ISFSI & Fuel Transfer Operations	$ 270.2	$ -	$ -	$ -	$ -	$ 270.2
3	Final Site Restoration	6.9	-	-	-	-	6.9
4	ISFSI Aging Management	-	-	-	-	36.5	36.5
6	Substructure Removal	273.0	-	-	-	-	273.0
7	Other Projects	189.8	-	-	-	(90.2)	99.6
8	GTCC Waste Storage	-	-	-	-	26.6	26.6
9	Plant Easement/Lease Renewals	-	-	-	-	27.1	27.1
10	Offshore Conduit Removal	91.6	-	-	-	-	91.6
11	ISFSI Demolition	19.2	-	-	-	-	19.2
12	Completed Projects	214.0	-	(90.7)	-	-	123.3
14							
15	**Undistributed Activities**						
16	Contracted Services	$ -	$ -	$ -	$ 225.2	$ -	$ 225.2
17	Service Level Agreements	168.2	-	-	-	-	168.2
19	Labor-Staffing	986.2	-	-	-	-	986.2
20	All Other Non-Labor	848.8	-	-	(225.2)	-	623.6
22							
23	**Total**	**$ 4,478.6**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,478.6**

General Note:
Totals may not reconcile due to rounding.

Appendix D

Declaration of Todd R. Adler Regarding the Confidentiality of Certain Data

SCE's 2018 NUCLEAR DECOMMISSIONING COST TRIENNIAL PROCEEDING

DECLARATION OF TODD R. ADLER

REGARDING THE CONFIDENTIALITY OF CERTAIN DATA

I, Todd R. Adler, declare and state:

1. I am employed by Southern California Edison (SCE) as a Principal Manager for Nuclear Projects Management, San Onofre Nuclear Generating Station (SONGS). In my position as Principal Manager, I have responsibility regarding the Decommissioning General Contractor (DGC) Agreement between SCE, Energy*Solutions* Services, Inc. (Energy*Solutions*), and AECOM Energy & Construction, Inc. (AECOM), dated December 20, 2016 (DGC Agreement). EnergySolutions and AECOM formed a joint venture known as SONGS Decommissioning*Solutions* (SDS). I also am familiar with the Independent Spent Fuel Storage Installation (ISFSI) Agreement between SCE and Holtec International (ISFSI Agreement), dated December 5, 2015. I had responsibility for overseeing and reviewing Exhibits SCE-03 and SCE-05, which contain certain confidential information pertaining to the DGC Agreement and ISFSI Agreement. Thomas J. Palmisano, Vice President of SONGS Decommissioning and Chief Nuclear Officer, delegated authority to me to sign this declaration regarding the confidentiality of this information, as described below.

2. I am making this declaration in accordance with the instructions set forth in Decision 16-08-024 and Decision 17-09-023 of R. 14-11-001, which were issued August 25, 2016, and September 28, 2017, respectively, and govern the submission of confidential documents to the Commission.

3. I have personal knowledge of the facts and representations herein and, if called upon to testify, could and would do so, except for those facts expressly stated to be based upon information and belief, and as to those matters, I believe them to be true.

4. Listed below are the data for which SCE is seeking confidential protection and the basis for SCE's confidentiality request. Paragraphs 5-10 also provide additional reasons supporting SCE's confidentiality claim.

Location of Confidential Data	Pages (if available)	Description of Information that is Confidential	Basis for SCE's Confidentiality Claim
Exhibit SCE-03	8, 14, 20-21, 37-38 Appendix B, DCE, pp. B-9, 18-19, 21, 23, 34-35, 45-47, 49, 60-63, 65, 68-72, 74, 77. Appendix C, p. C-1.	1. DGC Agreement contract terms, including decommissioning plans and pricing terms contained therein. 2. Contingency and cost-estimating information pertaining to the DGC Agreement and ISFSI Agreement.	California Gov. Code § 6255 (the public interest served by not disclosing the information is clearly outweighed by the public interest served by disclosure of the record).
Exhibit SCE-05	34	1. DGC Agreement contract terms, including decommissioning plans and pricing terms contained therein.	California Gov. Code § 6255 (the public interest served by not disclosing the information is clearly outweighed by the public interest served by disclosure of the record).

5. Both the DGC Agreement and ISFSI Agreement require SCE to make reasonable efforts to protect the confidentiality of the terms and conditions in the agreements. The agreements require confidentiality because they contain commercially sensitive pricing terms and proprietary information, such as work sequencing and scope. If this information was publicly disclosed without protection, competitors, including potential vendors for decommissioning sub-contract work and other activities, could mis-use the information to the detriment of SCE's customers. For example, if a vendor seeking to bid on a subcontract or another activity knew the DGC Agreement or ISFSI Agreement pricing terms, the vendor would have an opportunity to adjust its bid prices (e.g., the vendor could bid higher than it otherwise may have bid).

6. Public release of this information could also hinder SCE's ability to obtain favorable contract terms for related decommissioning work not covered under the DGC Agreement and ISFSI Agreement. For example, if a vendor (who SCE has not yet contracted with for SONGS decommissioning) was aware of various terms in the DGC Agreement and ISFSI Agreement, the

vendor could mis-use this information during contract negotiations to extract terms favorable to the vendor that the vendor may not have otherwise sought.

7. Finally, it is also in the best interest of the long-term success of the SONGS decommissioning project that SDS and Holtec remain commercially competitive throughout the terms of the DGC Agreement and ISFSI Agreement, respectively. Both agreements are long-term agreements that will require SDS' and Holtec's continued performance for the next decade and beyond. If information regarding the agreements was disclosed without protection, their competitors could mis-use the information against them during the bidding process for other decommissioning projects across the world and potentially threaten the financial health of both companies. This in turn could threaten the companies' ability to complete contractually required services for SONGS in the future without interruption.

8. The other category of information that SCE seeks to maintain as confidential is contingency. SCE has applied various contingency amounts on the remaining decommissioning work identified in the 2017 SONGS 2&3 decommissioning cost estimate (DCE) submitted in this proceeding, including work to be completed under the DGC Agreement and ISFSI Agreement. The contingency reflects SCE's judgment of potential costs, based on the technical complexity, contracting status, estimating approach, and timing, of the remaining work scope. It is in SCE customers' interest for contingency included for the DGC Agreement and ISFSI Agreement to be protected as confidential, because the disclosure of the information without protection could allow vendors to mis-use the information to the detriment of SCE's customers. For example, if a vendor (including SDS, Holtec, or one of their competitors) knew the contingency SCE has applied in the 2017 DCE to work to be completed under the DGC Agreement and ISFSI Agreement, the vendor would have an opportunity to manipulate its negotiating strategy pertaining to new contracts and/or change orders regarding that work (e.g., the vendor could demand higher prices than it otherwise would have demanded).

9. The confidential information identified in Paragraph 4 cannot be provided in a form that can be further aggregated, redacted, summarized, masked, or otherwise protected in a manner that would allow partial disclosure of the data while protecting confidential information.

10. For the reasons described above, the confidential information should be protected from public disclosure. Information regarding the DGC Agreement and ISFSI Agreement, including the pricing terms of those agreements and contingency SCE applied in the 2017 DCE for work remaining under those agreements, is market sensitive information that should remain confidential under GO-66-C Section 2.2(b) ("unfair business advantage") and GO 66-C Section 2.8 ("Information obtained in confidence from other than a business regulated by this Commission where the disclosure would be against the public interest").

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on March 13, 2018 at San Onofre Nuclear Generating Station, near San Clemente, California.

/s/ Todd R. Adler
Todd R. Adler

Appendix E

SONGS Mesa Lease and Station Easement Boundaries

SONGS
Mesa Lease and Station Easement Boundaries
Parcel 5
Parcel 6
Parcel 7
Parcels 8 and 9
Plant Site
San Onofre State Beach
5
0 0.05 0.1 0.2 Miles
1 in = 0.1 miles
Date: 3/12/2018
File Name: SONGS_ParcelMap_bw.mxd
Version: 10.3
Created By: E. Garcia
Real Properties Geospatial Analysis
Features depicted herein are planning level accuracy, and intended for informational purposes only. Distances and locations may be distorted at this scale. Always consult with the proper legal authorities.
Disclaimer: Use at your own risk. Real Properties Department and Rand McNally & Company assumes no liability or responsibility.
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SOUTHERN CALIFORNIA EDISON
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EXHIBIT 20

SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

Al Bates
Manager, Regulatory Affairs &
Oversight

10 CFR 50.82
10 CFR 72.30

March 20, 2018

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

Subject: **Docket Nos. 50-206, 50-361, 50-362, and 72-41**
10 CFR 50.82(a)(8)(v-vii) and 10 CFR 72.30(c)
Decommissioning Funding Status Report
San Onofre Nuclear Generating Station Units 1, 2, and 3
and Independent Spent Fuel Storage Installation

Dear Sir or Madam:

As required by 10 CFR 50.82(a)(8)(v), 10 CFR 50.82(a)(8)(vii), and 10 CFR 72.30(c), this letter provides the status of the decommissioning funding for San Onofre Nuclear Generating Station (San Onofre) Units 1, 2, and 3 and the San Onofre Independent Spent Fuel Storage Installation (ISFSI) as of December 31, 2017

Based on the requirements in 10 CFR 50.82(a)(8)(v) and 10 CFR 50.82(a)(8)(vii), this information is reported on an annual basis for SONGS Units 1, 2, and 3 because the units were permanently shut down and site-specific decommissioning cost estimates (DCEs) have been submitted for each of these units. In addition, based on the requirements in 10 CFR 72.30(c), information demonstrating the adequacy of funding for the San Onofre ISFSI is reported at intervals not to exceed three years, and is included. The required information for Southern California Edison, San Diego Gas & Electric, the City of Anaheim, and the City of Riverside is provided in the Enclosure.

There are no commitments contained in this letter or its enclosure.

If you have any questions regarding this matter, please contact me at (949) 368-6945.

Sincerely,

A001
NMSS01
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NMSS

Enclosure: San Onofre Nuclear Generating Station Units 1, 2, and 3 and ISFSI Decommissioning Funding Status Report for Calendar Year 2017

cc: K. Kennedy, Regional Administrator, NRC Region IV
M. G. Vaaler, NRC Project Manager, San Onofre Units 1, 2, and 3
W. C. Allen, NRC Project Manager, San Onofre ISFSI

Enclosure

San Onofre Nuclear Generating Station Units 1, 2, and 3 and Independent Spent Fuel Storage Installation (ISFSI) Decommissioning Funding Status Report for Calendar Year 2017

San Onofre Nuclear Generating Station Units 1, 2, and 3 and Independent Spent Fuel Storage Installation (ISFSI) Decommissioning Funding Status Report For Calendar Year 2017

San Onofre Unit 1 was a pressurized water reactor (PWR) rated at 1347 MWt. San Onofre Units 2 and 3 were pressurized water reactors (PWR) rated at 3438 MWt. Provided below is the information required by 10 CFR 50.82(a)(8)(v) and (vii) for San Onofre Units 1, 2, and 3; and the information required by 10 CFR 72.30(b) for the San Onofre ISFSI. This information is reported every year for San Onofre Units 1, 2, and 3 because site-specific decommissioning cost estimates (DCEs) have been submitted for them and they are currently being decommissioned.

The San Onofre ISFSI is located on the partially decommissioned site of San Onofre Unit 1, and is operated under a 10 CFR 72 General License issued to the holders of a 10 CFR 50 license.

The SONGS Unit 1 co-owners are reported as follows:

Southern California Edison (SCE)	80.00 %
San Diego Gas & Electric (SDG&E)	20.00 %
	100.00 %

The San Onofre Units 2 and 3 co-owners are reported as follows:

Southern California Edison (SCE)	78.21 %
San Diego Gas & Electric (SDG&E)	20.00 %
City of Anaheim (Anaheim)	0.00 %
City of Riverside (Riverside)	1.79 %

The decommissioning liability is shared between the current owners and former owner, Anaheim, as set forth below for each unit:

Owner	Unit 1 Decommissioning Liability	Unit 2 Decommissioning Liability	Unit 3 Decommissioning Liability
SCE	80.00%	75.7363%	75.7475%
SDG&E	20.00%	20.0000%	20.0000%
Anaheim	0.00%	2.4737%	2.4625%
Riverside	0.00%	1.7900%	1.7900%

All dollar amounts are in 100% share, 2017 dollars.

1) The estimated costs to decommission San Onofre Units 1, 2, and 3, and the San Onofre ISFSI, including all decommissioning and spent fuel storage costs estimated to be required pursuant to 10 CFR 50.75(b) and (c); 10 CFR 50.54(bb); and 10 CFR 72.30(b) are shown below:

The site-specific estimates for decommissioning include the following radiological decommissioning costs associated with terminating the site license pursuant to 10 CFR 50.75(b); non-radiological site restoration costs; spent fuel storage costs pursuant to 10 CFR 50.54(bb); and ISFSI decommissioning costs pursuant to 10 CFR 72.30(b):

	San Onofre Unit 1[1]
Estimate of License Termination Costs	$ 76.8 million
Less: Lic. Term. Costs during 2017	$ 1.3 million
"To Go" License Termination Costs	$ 75.5 million
Estimate of Site Restoration Costs	$ 92.6 million
Less: Site Restor. Costs during 2017	$ 0.3 million
"To Go" Site Restoration Costs	$ 92.3 million
Estimate of Fuel Storage Costs	$ 46.0 million
Less: Fuel Storage Costs during 2017	$ 0.4 million
"To Go" Fuel Storage Costs	$ 45.6 million
Estimate of ISFSI Decommissioning Costs	$ 5.3 million
Total Unit 1 "To Go" Costs as of 1/1/2018	$ 218.7 million

	San Onofre Unit 2[2]
Estimate of License Termination Costs	$1,017.0 million
Less: Lic. Term. Costs through 12/31/2017	$ 305.2 million
"To Go" License Termination Costs	$ 711.8 million
Estimate of Site Restoration Costs	$ 527.8 million
Less: Site Restor. Costs through 12/31/2017	$ 90.5 million
"To Go" Site Restoration Costs	$ 437.3 million
Estimate of Fuel Storage Costs	$ 687.0 million
Less: Fuel Storage Costs through 12/31/2017	$ 259.0 million
"To Go" Fuel Storage Costs	$ 428.0 million
Estimate of ISFSI Decommissioning Costs	$ 18.9 million
Total Unit 2 "To Go" Costs as of 1/1/2018	$1,596.0 million

	San Onofre Unit 3[2]
Estimate of License Termination Costs	$1,007.5 million
Less: Lic. Term. Costs through 12/31/2017	$ 302.5 million
"To Go" License Termination Costs	$ 705.0 million
Estimate of Site Restoration Costs	$ 746.6 million
Less: Site Restor. Costs through 12/31/2017	$ 102.2 million
"To Go" Site Restoration Costs	$ 644.4 million
Estimate of Fuel Storage Costs	$ 724.6 million
Less: Fuel Storage Costs through 12/31/2017	$ 254.7 million
"To Go" Fuel Storage Costs	$ 469.9 million
Estimate of ISFSI Decommissioning Costs	$ 18.9 million
Total Unit 3 "To Go" Costs as of 1/1/2018	$1,838.2 million

The site-specific decommissioning cost estimates for San Onofre Units 1, 2, and 3 and the San Onofre ISFSI include: (1) the cost to perform all decommissioning activities; (2) the cost of meeting the 10 CFR 20.1402 radiological criteria for unrestricted site use; and (3) adequate contingency factors for all costs.

2) Each San Onofre co-owner has established one or more external sinking trust fund accounts as provided in 10 CFR 50.75(e)(1)(ii) for their respective shares of the San Onofre Units 1, 2, and 3 decommissioning obligation, which also includes the San Onofre ISFSI. The Decommissioning Trust Fund amounts remaining at the end of calendar year 2017 (net of pending Trust Fund withdrawals and estimated capital gains taxes) are:[3][4][5]

Co-Owner	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
SCE	$ 303.5 million	$ 1,180.4 million	$ 1,370.9 million
SDG&E [5]	$ 150.5 million	$ 357.5 million	$ 412.5 million
Anaheim [5]	N/A	$ 52.2 million	$ 52.2 million
Riverside [5]	N/A	$ 27.9 million	$ 30.8 million
TOTAL	$ 454.0 million	$ 1,618.0 million	$ 1,866.4 million

3) Each San Onofre co-owner deposits its decommissioning fund contributions into their respective external sinking fund accounts as provided in 10 CFR 50.75(e)(1)(ii). The annual amounts projected to be collected in 2018 are:

Co-Owner	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
SCE	$ 0.0 million	$ 0.0 million	$ 0.0 million
SDG&E [5]	$ 0.0 million	$ 0.0 million	$ 0.0 million
Anaheim [5]	N/A	$ 0.0 million	$ 0.0 million
Riverside [5]	N/A	$ 0.0 million	$ 0.0 million
TOTAL	$ 0.0 million	$ 0.0 million	$ 0.0 million

4) The amounts spent on San Onofre Units 1, 2, and 3 decommissioning work performed during 2017 are summarized below:

Cost Category	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
License Term.	$ 1.5 million	$ 91.7 million	$ 88.9 million
Site Restoration	$ 0.9 million	$ 5.5 million	$ 11.3 million
Spent Fuel Storage	$ 0.6 million	$ 52.3 million	$ 53.3 million
ISFSI Decom.	$ 0.0 million	$ 0.0 million	$ 0.0 million
TOTAL	$ 3.0 million	$ 149.5 million	$ 153.5 million

5) The composite escalation rate and after tax investment rates of return for San Onofre Units 1, 2, and 3 Decommissioning are summarized below:

Composite Rate	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
Rate of Return	3.17%	3.32%	3.32%
Escalation	2.69%	2.91%	2.91%
Real Earnings Rate	0.48%	0.41%	0.41%

The composite investment rates of return less the composite escalation rates yield composite real earnings rates less than the 2% real rate of return allowed under 10 CFR 50.75(e)(1)(ii).

6) None of the co-owners of San Onofre Units 1, 2, and 3 or the San Onofre ISFSI is relying on any contracts for the purposes of providing decommissioning funding pursuant to 10 CFR 50.75(e)(1)(v). There have been no modifications to the method of providing financial assurance.

7) The amounts of decommissioning funds available as of December 31, 2017 for San Onofre Units 1, 2, and 3 License Termination, Site Restoration, Spent (Irradiated) Fuel Management, and ISFSI Decommissioning costs are shown in the tables below:[4]

San Onofre Unit 1	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2017 Net Trust Balance
License Termination Costs	$ 75.5 million	34.5%	$ 156.7 million
Site Restoration Costs	$ 92.3 million	42.2%	$ 191.7 million
Spent Fuel Management Costs	$ 45.6 million	20.8%	$ 94.6 million
ISFSI Decommissioning Costs	$ 5.3 million	2.4%	$ 11.0 million
TOTAL	$ 218.7 million	100.0%	$ 454.0 million

San Onofre Unit 2	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2017 Net Trust Balance
License Termination Costs	$ 711.8 million	44.6%	$ 721.6 million
Site Restoration Costs	$ 437.4 million	27.4%	$ 443.4 million
Spent Fuel Management Costs	$ 428.0 million	26.8%	$ 433.9 million
ISFSI Decommissioning Costs	$ 18.8 million	1.2%	$ 19.1 million
TOTAL	$ 1,596.0 million	100.0%	$ 1,618.0 million

San Onofre Unit 3	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2017 Net Trust Balance
License Termination Costs	$ 705.0 million	38.4%	$ 715.8 million
Site Restoration Costs	$ 644.4 million	35.0%	$ 654.2 million
Spent Fuel Management Costs	$ 469.9 million	25.6%	$ 477.2 million
ISFSI Decommissioning Costs	$ 18.9 million	1.0%	$ 19.2 million
TOTAL	$ 1,838.2 million	100.0%	$ 1,866.4 million

8) Key assumptions pertaining to spent fuel storage and ISFSI decommissioning:

San Onofre Unit 1:

- Permanently retired on November 30, 1992
- 395 fuel assemblies in 17 canisters are located in the SONGS ISFSI
- 1 canister of Greater Than Class C (GTCC) waste is located in the SONGS ISFSI
- The U.S. Department of Energy (DOE) will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Unit 1 fuel from the ISFSI by 2034

San Onofre Unit 2:

- Permanently ceased operations on June 7, 2013
- 408 fuel assemblies in 17 canisters are currently located in the SONGS ISFSI
- Transfer of the remaining 1,318 fuel assemblies from the spent fuel pool to the SONGS ISFSI commenced in January 2018 and is scheduled to be completed by mid-2019
- Greater Than Class C (GTCC) waste will be placed in the SONGS ISFSI per schedule to be developed by Decommissioning General Contractor
- DOE will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Units 2 & 3 fuel from the ISFSI by 2049

San Onofre Unit 3:

- Permanently ceased operations on June 7, 2013
- 384 fuel assemblies in 16 canisters are currently located in the SONGS ISFSI
- Transfer of the remaining 1,350 fuel assemblies from the spent fuel pool to the SONGS ISFSI commenced in January 2018 and is scheduled to be completed by mid-2019
- Greater Than Class C (GTCC) waste will be placed in the SONGS ISFSI per schedule to be developed by Decommissioning General Contractor
- DOE will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Units 2 & 3 fuel from the ISFSI by 2049

San Onofre ISFSI:

- The San Onofre ISFSI will be decommissioned and the remaining plant and ISFSI site will be decontaminated to meet 10 CFR 20.1402 site release criteria for unrestricted use as required to terminate the Part 50 General License by 2051.

Notes:

(1) The new site-specific decommissioning cost estimate for San Onofre Unit 1 that was submitted to the California Public Utilities Commission (CPUC) on March 15, 2018, includes the radiological costs associated with terminating the site license, non-radiological costs, and fuel storage costs.

(2) The new site-specific decommissioning cost estimate for San Onofre Units 2 and 3 that was submitted to the CPUC on March 15, 2018 includes the radiological costs associated with terminating the site license, non-radiological costs, and fuel storage costs.

(3) During the period between June 7, 2013 and December 31, 2017, SCE incurred costs of $654.8 million for San Onofre Unit 2 and $659.4 million for San Onofre Unit 3 (100% share, 2017$). Some of the San Onofre decommissioning co-owners have not yet withdrawn funds for all or part of these costs from their Decommissioning Trusts. Therefore, the Net Balances are the differences between the December 31, 2017 Decommissioning Trust Balances and the 2013-2017 incurred or accrued costs.

(4) Pursuant to 10 CFR 72.30(e)(5), power reactor licensees are authorized to use the financial assurance methods provided for in 10 CFR 50.75(e). All four San Onofre co-owners recover the cost of decommissioning pursuant to cost-of-service rate regulation and, therefore, are eligible to provide assurance using the external sinking fund method provided for in 10 CFR 50.75(e)(1)(ii). To the extent the decommissioning costs are fully funded and annual deposits are no longer required, the Co-Participants provide assurance using the prepayment method provided for in 10 CFR 50.75(e)(1)(i).

SCE and SDG&E are also required to accumulate sufficient funds to decommission the SONGS facility under the California Nuclear Facilities Decommissioning Act, CA Public Utilities Code Section 8321, et seq. The CPUC has construed the SONGS decommissioning obligation to include: (1) radiological decommissioning as required to terminate the NRC licenses, (2) spent fuel storage (including ISFSI decommissioning), and (3) site restoration as required to terminate the SONGS site lease contracts granted by the U.S. Department of the Navy and the California State Lands Commission.

Under CA Public Utilities Code Section 8326(a)(2), SCE and SDG&E are required to update their site-specific nuclear facility decommissioning cost estimates periodically to reflect changes in decommissioning regulation, technology, and economics, for the purpose of adjusting contribution levels to their decommissioning trust.

Under CA Public Utilities Code Sections 8326(b), 8327, 8328, and 8329, the CPUC periodically reviews SCE and SDG&E's site-specific decommissioning cost estimates for the purpose of considering changes in electrical rates to ensure that sufficient funds will be available for payment of all decommissioning costs. The Cities of Anaheim and Riverside are not under the jurisdiction of the CPUC.

(5) SCE is submitting information with respect to the San Onofre co-owners, SDG&E, Anaheim, and Riverside, on their behalf, and they are responsible for the completeness and accuracy of their respective information.

(6) The current site-specific decommissioning cost estimates for San Onofre Unit 1 and for San Onofre Units 2 and 3 assume that the DOE will commence transporting spent fuel assemblies in 2028. This assumption may be updated periodically due to the ongoing uncertainties regarding the availability of a permanent repository for spent fuel.

EXHIBIT 21

SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

Al Bates
Manager, Regulatory Affairs &
Oversight

10 CFR 50.82
10 CFR 72.30

March 14, 2019

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

Subject: **Docket Nos. 50-206, 50-361, 50-362, and 72-41**
10 CFR 50.82(a)(8)(v-vii) and 10 CFR 72.30(c)
Decommissioning Funding Status Report 2018
San Onofre Nuclear Generating Station Units 1, 2, and 3
and Independent Spent Fuel Storage Installation

Dear Sir or Madam:

As required by 10 CFR 50.82(a)(8)(v), 10 CFR 50.82(a)(8)(vii), and 10 CFR 72.30(c), this letter provides the status of the decommissioning funding for San Onofre Nuclear Generating Station (San Onofre) Units 1, 2, and 3 and the San Onofre Independent Spent Fuel Storage Installation (ISFSI) as of December 31, 2018.

Based on the requirements in 10 CFR 50.82(a)(8)(v) and 10 CFR 50.82(a)(8)(vii), this information is reported on an annual basis for SONGS Units 1, 2, and 3 because the units were permanently shut down and site-specific decommissioning cost estimates (DCEs) have been submitted for each of these units. In addition, based on the requirements in 10 CFR 72.30(c), information demonstrating the adequacy of funding for the San Onofre ISFSI is reported at intervals not to exceed three years, and is included. The required information for Southern California Edison, San Diego Gas & Electric, the City of Anaheim, and the City of Riverside is provided in the Enclosure.

There are no commitments contained in this letter or its enclosure.

If you have any questions regarding this matter, please contact me at (949) 368-6945.

Sincerely,

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NMSS

Enclosure: San Onofre Nuclear Generating Station Units 1, 2, and 3 and ISFSI Decommissioning Funding Status Report for Calendar Year 2018

cc: S. Morris, Regional Administrator, NRC Region IV
M. G. Vaaler, NRC Project Manager, San Onofre Units 1, 2, and 3

Enclosure

San Onofre Nuclear Generating Station Units 1, 2, and 3 and Independent Spent Fuel Storage Installation (ISFSI) Decommissioning Funding Status Report for Calendar Year 2018

San Onofre Nuclear Generating Station Units 1, 2, and 3 and Independent Spent Fuel Storage Installation (ISFSI) Decommissioning Funding Status Report For Calendar Year 2018

San Onofre Unit 1 was a pressurized water reactor (PWR) rated at 1347 MWt. San Onofre Units 2 and 3 were pressurized water reactors (PWR) rated at 3438 MWt. Provided below is the information required by 10 CFR 50.82(a)(8)(v) and (vii) for San Onofre Units 1, 2, and 3; and the information required by 10 CFR 72.30(b) for the San Onofre ISFSI. This information is reported every year for San Onofre Units 1, 2, and 3 because they are permanently shut down and site-specific decommissioning cost estimates (DCEs) have been submitted for them.

The San Onofre ISFSI is located on the partially decommissioned site of San Onofre Unit 1, and is operated under a 10 CFR 72 General License issued to the holders of a 10 CFR 50 license.

The SONGS Unit 1 co-owners are reported as follows:

Southern California Edison (SCE)	80.00 %
San Diego Gas & Electric (SDG&E)	20.00 %
	100.00 %

The San Onofre Units 2 and 3 co-owners are reported as follows:

Southern California Edison (SCE)	78.21 %
San Diego Gas & Electric (SDG&E)	20.00 %
City of Anaheim (Anaheim)	0.00 %
City of Riverside (Riverside)	1.79 %

The decommissioning liability is shared between the current owners and former owner, Anaheim, as set forth below for each unit:

Owner	Unit 1 Decommissioning Liability	Unit 2 Decommissioning Liability	Unit 3 Decommissioning Liability
SCE	80.00%	75.7363%	75.7475%
SDG&E	20.00%	20.0000%	20.0000%
Anaheim	0.00%	2.4737%	2.4625%
Riverside	0.00%	1.7900%	1.7900%

All dollar amounts are in 100% share, 2018 dollars.

1) The estimated costs to decommission San Onofre Units 1, 2, and 3, and the San Onofre ISFSI, including all decommissioning and spent fuel storage costs estimated to be required pursuant to 10 CFR 50.75(b) and (c); 10 CFR 50.54(bb); and 10 CFR 72.30(b) are shown below:

The site-specific estimates for decommissioning include the following radiological decommissioning costs associated with terminating the site license pursuant to 10 CFR 50.75(b); non-radiological site restoration costs; spent fuel storage costs pursuant to 10 CFR 50.54(bb); and ISFSI decommissioning costs pursuant to 10 CFR 72.30(b):

	San Onofre Unit 1[1]
Estimate of License Termination Costs	$ 78.8 million
Less: Lic. Term. Costs during 2018	$ 1.5 million
"To Go" License Termination Costs	$ 77.3 million
Estimate of Fuel Storage Costs	$ 47.2 million
Less: Fuel Storage Costs during 2018	$ 2.3 million
"To Go" Fuel Storage Costs	$ 44.9 million
Estimate of ISFSI Decommissioning Costs	$ 5.4 million
Estimate of Site Restoration Costs	$ 94.7 million
Less: Site Restor. Costs during 2018	$ 0.4 million
"To Go" Site Restoration Costs	$ 94.3 million
Total Unit 1 "To Go" Costs as of 1/1/2019	$ 221.9 million

	San Onofre Unit 2[2]
Estimate of License Termination Costs	$1,045.0 million
Less: Lic. Term. Costs through 12/31/2018	$ 345.7 million
"To Go" License Termination Costs	$ 699.3 million
Estimate of Fuel Storage Costs	$ 705.7 million
Less: Fuel Storage Costs through 12/31/2018	$ 314.8 million
"To Go" Fuel Storage Costs	$ 390.9 million
Estimate of ISFSI Decommissioning Costs	$ 19.4 million
Estimate of Site Restoration Costs	$ 541.7 million
Less: Site Restor. Costs through 12/31/2018	$ 99.9 million
"To Go" Site Restoration Costs	$ 441.8 million
Total Unit 2 "To Go" Costs as of 1/1/2019	$1,551.4 million

	San Onofre Unit 3[2]
Estimate of License Termination Costs	$1,035.2 million
Less: Lic. Term. Costs through 12/31/2018	$ 346.4 million
"To Go" License Termination Costs	$ 688.8 million
Estimate of Fuel Storage Costs	$ 743.8 million
Less: Fuel Storage Costs through 12/31/2018	$ 312.0 million
"To Go" Fuel Storage Costs	$ 431.8 million
Estimate of ISFSI Decommissioning Costs	$ 19.4 million
Estimate of Site Restoration Costs	$ 765.7 million
Less: Site Restor. Costs through 12/31/2018	$ 114.7 million
"To Go" Site Restoration Costs	$ 651.0 million
Total Unit 3 "To Go" Costs as of 1/1/2019	$1,791.0 million

The site-specific decommissioning cost estimates for San Onofre Units 1, 2, and 3 and the San Onofre ISFSI include: (1) the cost to perform all decommissioning activities; (2) the cost of meeting the 10 CFR 20.1402 radiological criteria for unrestricted site use; and (3) adequate contingency factors for all costs.

2) Each San Onofre co-owner has established one or more external sinking trust fund accounts as provided in 10 CFR 50.75(e)(1)(ii) for their respective shares of the San Onofre Units 1, 2, and 3 decommissioning obligation, which also includes the San Onofre ISFSI. The Decommissioning Trust Fund amounts remaining at the end of calendar year 2018 (net of pending Trust Fund withdrawals and estimated capital gains taxes) are:[3][4][5]

Co-Owner	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
SCE	$ 289.4 million	$ 1,085.6 million	$ 1,267.5 million
SDG&E [5]	$ 149.3 million	$ 333.9 million	$ 387.5 million
Anaheim [5]	N/A	$ 51.4 million	$ 51.4 million
Riverside [5]	N/A	$ 26.9 million	$ 29.8 million
TOTAL	$ 438.7 million	$ 1,497.8 million	$ 1,736.2 million

3) Each San Onofre co-owner deposits its decommissioning fund contributions into their respective external sinking fund accounts as provided in 10 CFR 50.75(e)(1)(ii). The annual amounts projected to be collected in 2018 are:

Co-Owner	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
SCE	$ 0.0 million	$ 0.0 million	$ 0.0 million
SDG&E [5]	$ 0.0 million	$ 0.0 million	$ 0.0 million
Anaheim [5]	N/A	$ 0.0 million	$ 0.0 million
Riverside [5]	N/A	$ 0.0 million	$ 0.0 million
TOTAL	$ 0.0 million	$ 0.0 million	$ 0.0 million

4) The amounts spent on San Onofre Units 1, 2, and 3 decommissioning work performed during 2018 are summarized below:

Cost Category	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
License Term.	$ 0.1 million	$ 32.0 million	$ 35.4 million
Spent Fuel Storage	$ 1.8 million	$ 48.4 million	$ 50.2 million
ISFSI Decom.	$ 0.0 million	$ 0.0 million	$ 0.0 million
Site Restoration	$ 0.2 million	$ 6.7 million	$ 9.6 million
TOTAL	$ 2.1 million	$ 87.1 million	$ 95.2 million

5) The composite escalation rate and after tax investment rates of return for San Onofre Units 1, 2, and 3 Decommissioning are summarized below:

Composite Rate	San Onofre Unit 1	San Onofre Unit 2	San Onofre Unit 3
Rate of Return	2.95%	3.04%	3.04%
Escalation	2.69%	2.92%	2.92%
Real Earnings Rate	0.26%	0.12%	0.12%

The composite investment rates of return less the composite escalation rates yield composite real earnings rates less than the 2% real rate of return allowed under 10 CFR 50.75(e)(1)(ii).

6) None of the co-owners of San Onofre Units 1, 2, and 3 or the San Onofre ISFSI is relying on any contracts for the purposes of providing decommissioning funding pursuant to 10 CFR 50.75(e)(1)(v). There have been no modifications to the method of providing financial assurance.

7) The amounts of decommissioning funds available as of December 31, 2018 for San Onofre Units 1, 2, and 3 License Termination, Site Restoration, Spent Fuel Management, and ISFSI Decommissioning costs are shown in the tables below:[4]

San Onofre Unit 1	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2018 Net Trust Balance
License Termination Costs	$ 77.3 million	34.8%	$ 152.8 million
Spent Fuel Management Costs	$ 44.9 million	20.2%	$ 88.8 million
ISFSI Decommissioning Costs	$ 5.4 million	2.4%	$ 10.7 million
Site Restoration Costs	$ 94.3 million	42.5%	$ 186.4 million
TOTAL	$ 221.9 million	100.0%[7]	$ 438.7 million

San Onofre Unit 2	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2018 Net Trust Balance
License Termination Costs	$ 699.3 million	45.1%	$ 675.5 million
Spent Fuel Management Costs	$ 390.9 million	25.2%	$ 377.4 million
ISFSI Decommissioning Costs	$ 19.4 million	1.2%	$ 18.0 million
Site Restoration Costs	$ 441.8 million	28.5%	$ 426.9 million
TOTAL	$ 1,551.4 million	100.0%	$ 1,497.8 million

San Onofre Unit 3	Estimated "To Go" Decommissioning Cost	Cost Ratios	12/31/2018 Net Trust Balance
License Termination Costs	$ 688.8 million	38.5%	$ 668.4 million
Spent Fuel Management Costs	$ 431.8 million	24.1%	$ 418.4 million
ISFSI Decommissioning Costs	$ 19.4 million	1.1%	$ 19.1 million
Site Restoration Costs	$ 651.0 million	36.3%	$ 630.3 million
TOTAL	$ 1,791.0 million	100.0%	$ 1,736.2 million

8) Key assumptions pertaining to spent fuel storage and ISFSI decommissioning:

San Onofre Unit 1:

- Permanently retired on November 30, 1992
- 395 fuel assemblies in 17 canisters are located in the ISFSI
- 1 canister of Greater Than Class C (GTCC) waste is located in the ISFSI
- The U.S. Department of Energy (DOE) will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Unit 1 fuel from the ISFSI by 2034

San Onofre Unit 2:

- Permanently ceased operations on June 7, 2013
- 1,000 fuel assemblies in 33 canisters are currently located in the ISFSI
- Transfer of the remaining 726 fuel assemblies from the spent fuel pool to the SONGS ISFSI is scheduled to be completed during 2019
- Greater Than Class C (GTCC) waste will be placed in the SONGS ISFSI per schedule to be developed by Decommissioning General Contractor
- DOE will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Units 2 & 3 fuel from the ISFSI by 2049

San Onofre Unit 3:

- Permanently ceased operations on June 7, 2013
- 865 fuel assemblies in 29 canisters are currently located in the SONGS ISFSI
- Transfer of the remaining 869 fuel assemblies from the spent fuel pool to the SONGS ISFSI is scheduled to be completed during 2019
- Greater Than Class C (GTCC) waste will be placed in the SONGS ISFSI per schedule to be developed by Decommissioning General Contractor
- DOE will commence transporting spent fuel assemblies in 2028[6]
- DOE will remove last SONGS Units 2 & 3 fuel from the ISFSI by 2049

San Onofre ISFSI:

- The San Onofre ISFSI will be decommissioned and the remaining plant and ISFSI site will be decontaminated to meet 10 CFR 20.1402 site release criteria for unrestricted use as required to terminate the Part 50 General License by 2051.

Notes:

(1) The new site-specific decommissioning cost estimate for San Onofre Unit 1 that was submitted to the California Public Utilities Commission (CPUC) on March 15, 2018, includes the radiological costs associated with terminating the site license, site restoration costs, and fuel storage costs.

(2) The new site-specific decommissioning cost estimate for San Onofre Units 2 and 3 that was submitted to the CPUC on March 15, 2018 includes the radiological costs associated with terminating the site license, site restoration costs, and fuel storage costs.

(3) During the period between June 7, 2013 and December 31, 2018, SCE incurred costs of $760.4 million for San Onofre Unit 2 and $773.1 million for San Onofre Unit 3 (100% share, 2018$). In 2018, SDG&E and the City of Riverside did not withdraw funds for all or part of these costs from their Decommissioning Trusts. Therefore, their Net Balances are the differences between the December 31, 2018 Decommissioning Trust Balances and the 2013-2018 incurred or accrued costs.

(4) Pursuant to 10 CFR 72.30(e)(5), power reactor licensees are authorized to use the financial assurance methods provided for in 10 CFR 50.75(e). All four San Onofre co-owners recover the cost of decommissioning pursuant to cost-of-service rate regulation and, therefore, are eligible to provide assurance using the external sinking fund method provided for in 10 CFR 50.75(e)(1)(ii). To the extent the decommissioning costs are fully funded and annual deposits are no longer required, the Co-Participants provide assurance using the prepayment method provided for in 10 CFR 50.75(e)(1)(i).

SCE and SDG&E are also required to accumulate sufficient funds to decommission the SONGS facility under the California Nuclear Facilities Decommissioning Act, CA Public Utilities Code Section 8321, et seq. The CPUC has construed the SONGS decommissioning obligation to include: (1) radiological decommissioning as required to terminate the NRC licenses, (2) spent fuel storage (including ISFSI decommissioning), and (3) site restoration as required to terminate the SONGS site lease contracts granted by the U.S. Department of the Navy and the California State Lands Commission.

Under CA Public Utilities Code Section 8326(a)(2), SCE and SDG&E are required to update their site-specific nuclear facility decommissioning cost estimates periodically to reflect changes in decommissioning regulation, technology, and economics, for the purpose of adjusting contribution levels to their decommissioning trust.

Under CA Public Utilities Code Sections 8326(b), 8327, 8328, and 8329, the CPUC periodically reviews SCE and SDG&E's site-specific decommissioning cost estimates for the purpose of considering changes in electrical rates to ensure that sufficient funds will be available for payment of all decommissioning costs. The Cities of Anaheim and Riverside are not under the jurisdiction of the CPUC.

(5) SCE is submitting information with respect to the San Onofre co-owners, SDG&E, Anaheim, and Riverside, on their behalf, and they are responsible for the completeness and accuracy of their respective information.

(6) The current site-specific decommissioning cost estimates for San Onofre Unit 1 and for San Onofre Units 2 and 3 assume that the DOE will commence transporting spent fuel assemblies in 2028. This assumption may be updated periodically due to the ongoing uncertainties regarding the availability of a permanent repository for spent fuel.

(7) Some numbers may not add precisely due to rounding. Any such errors are immaterial to the substantive information presented in this report.

EXHIBIT 22

NRC NEWS
Office of Public Affairs, Region IV
Arlington, TX. 76011-4511
www.nrc.gov

No: IV-19-012 May 21, 2019
Contact: Victor Dricks, 817-200-1128

NRC Has Determined Fuel Loading Can Be Safely Resumed at San Onofre Nuclear Generating Station

The Nuclear Regulatory Commission has determined that fuel loading can be safely resumed at the San Onofre Nuclear Generating Station. The San Clemente, Calif., plant is owned by Southern California Edison and permanently shut down in 2013.

Fuel loading operations were suspended following an Aug. 3, 2018, incident involving a loaded spent fuel storage canister that was misaligned and became stuck on a flange while being lowered into a storage vault. Information about the incident and the NRC's response is available on the NRC website.

The NRC made its determination following extensive review of technical data submitted by Edison regarding the possible effects of scratching on spent fuel canisters during fuel loading operations.

The NRC will hold a virtual public meeting/webinar from 2-3 p.m. Central Time (12-1 p.m. Pacific Time) on June 3. Members of the public will have an opportunity to submit written comments and questions via the webinar user interface following a presentation by NRC officials. NRC staff will provide participation guidance during the webinar.

Interested members of the public should register for the webinar on the NRC website, at which time a confirmation e-mail will be sent with details for joining the webinar via computer or mobile device. There is an option to listen via a phone bridge; however participants must first register for the webinar to obtain the phone bridge number.

EXHIBIT 23

BARNES & THORNBURG LLP

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Eric J. Beste
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September 6, 2019

Via Email

Edward J. Casey
James R. Evans, Jr.
Alston & Bird, LLP
333 South Hope Street, 16th floor
Los Angeles, CA 90071

Michael Zweiback
Zweiback Fiset & Coleman LLP
523 W. 6th Street, Suite 450
Los Angeles, CA 90014

Re: ***Public Watchdogs v. Southern California Edison Co., et al.,***
Case No. 19CV1635-JLS (MSB) (S.D. Cal.)

Dear Counsel:

As outlined in Judge Sammartino's Order from today, you have until September 20, 2019, to brief the legal objections you raised to our Amended Motion for Preliminary Injunction and Temporary Restraining Order. But based upon your client's public statements, it appears that additional canisters will be interred between now and the time Judge Sammartino has an opportunity to adjudicate this dispute. Further complicating the matter is the fact that the technology does not presently exist to remove canisters that have already been buried.

Previously, your clients voluntarily agreed to suspend the removal, transport, and burial of spent nuclear fuel for almost a year. Given that you share our concern for the health and safety of the public and environment, we are asking your clients to again suspend that process for the very brief time it will take Judge Sammartino to resolve the pending Motion. If your legal arguments are correct, and our client cannot bring this case in federal district court at this time, the matter will be decided in your favor in short order. If, however, Judge Sammartino grants some or all of our requested relief—even temporarily—we will have been prejudiced by the current briefing schedule, and your clients will have the challenge of complying with a court order that requires them to undo something that can't be undone.

We recognize that this request is unusual. But we trust you appreciate the gravity of the situation, and the need to preserve Judge Sammartino's ability to adjudicate this dispute on the merits while the possibility of relief still exists. Please let us know by Monday, September 9, if you will agree to this modest proposal.

Very truly yours,

Eric J. Beste

cc (via email): Valerie Torres
Assistant U.S. Attorney
United States Attorney's Office
for the Southern District of California
880 Front Street, Room 6293
San Diego, CA 92101

EXHIBIT 24

ALSTON & BIRD

333 South Hope Street, 16th Floor
Los Angeles, CA 90071-1410
213-576-1000 | Fax: 213-576-1100

Edward J. Casey | Direct Dial: 213-576-1005 | Email: ed.casey@alston.com

September 9, 2019

VIA EMAIL AND U.S. MAIL

Eric J. Beste, Esq.
Barnes & Thornburg LLP
655 West Broadway
Suite 900
San Diego, CA 92101-8484

Re: *Public Watchdogs v. Southern California Edison Company, et al.*
USDC Case No. 3:19-cv-01635-JM (MSB)

Dear Mr. Beste:

On behalf of Southern California Edison, San Diego Gas & Electric, and Sempra Energy (collectively the "SONGS Parties"), I am sending this letter to respond to your letter sent at 6 p.m. on Friday, September 6, 2019. In that letter you, as counsel for plaintiff Public Watchdogs ("Plaintiff"), requested that the SONGS Parties suspend the transfer of the spent nuclear fuel ("SNF") to the Independent Spent Fuel Storage Installation ("ISFSI") at the SONGS facility. However, Plaintiff's request is premised on a mischaracterization of key facts concerning the Nuclear Regulatory Commission's ("NRC") licensing process, and the SONGS Parties' spent fuel transfer and storage operations. The NRC completed a detailed review and analysis confirming the safety of the Holtec canister system and spent fuel transfer procedures, and has determined that the SONGS Parties may safely resume spent fuel transfer operations at SONGS.

Having received all necessary regulatory approvals from the NRC (the agency with exclusive jurisdiction over radiological matters) for the transfer of the SNF to Holtec canisters and storage of those canisters in the ISFSI, the SONGS Parties plan to safely continue the transfer operations so that they can timely move forward with decommissioning on behalf of their customers, and ultimately finding a permanent off-site location for SNF. Therefore, the SONGS Parties respectfully decline Plaintiff's request for a suspension of those operations. Further, having been provided with relevant information

in this letter, we expect that Plaintiff will satisfy its legal obligation to inform the District Court of these facts if it seeks to file any additional pleading with the Court prior to its reply brief on September 27, 2019.

Very truly yours,

Edward J. Casey

EJC/ysr

cc: Michael Zweiback, Esq.
(Via Email)
Valerie Torres, Asst. U.S. Attorney
(Via Email)

EXHIBIT 25

Office of the Inspector General
Report of Administrative Inquiry

March 23, 2010

William R. McCollum, Jr., LP 6A-C
Ralph E. Rodgers, WT 6A-K

(b) (7)(C)
(b) (7)(C)
HOLTEC INTERNATIONAL
555 LINCOLN DRIVE WEST
MARLTON, NEW JERSEY 08053
OIG FILE NO. 12E-102

This report was prepared at the request of Ralph E. Rodgers, Deputy General Counsel, Office of the General Counsel, Tennessee Valley Authority (TVA), to summarize investigative and audit efforts concerning the actions of (b) (7)(C) . These efforts were initiated following the receipt of a complaint that (b) (7)(C) had engaged in funneling money to a TVA employee, John L. (Jack) Symonds, to secure TVA nuclear contracts for HI. This report provides information related to how those payments were made to the TVA employee, (b) (7)(C) involvement with those payments and the pattern of behavior exhibited by (b) (7)(C) when attempting to acquire nuclear contracts. The report also reflects audit findings of overbilling by HI for equipment costs and the rationale provided by HI and TVA for the price difference at two of TVA's nuclear plants. The findings in this report were based on the statements of (b)(7)(D) , several witnesses, the statements of Mr. Symonds, former Brown Ferry Nuclear Plant (BFN) Technical Contract Manager, and documents included as attachments.

On August 3, 2007, Mr. Symonds pled guilty in U.S. federal court to making false financial statements to TVA by not disclosing receiving more than $54,000 from Krohn Enterprises LLC, a company he co-owned with his spouse. Mr. Symonds was paid by HI through another company called U. S. Tool & Die (UST&D). Mr. Symonds knew HI had contracted with TVA in November 2001 to design and construct a dry cask storage system for spent nuclear fuel rods at BFN, and had contracted with UST&D to fabricate some of the construction materials for the TVA BFN dry cask storage system. The money received by Mr. Symonds was used to pay personal expenses of Mr. Symonds and his spouse.

William R. McCollum, Jr.
Ralph E. Rodgers
Page 2
March 23, 2010

OVERVIEW

During June 2000, TVA needed above-ground storage containers to store spent nuclear fuel at Sequoyah Nuclear Plant (SQN). TVA entered into a contract with HI, for design and construction services, storage systems, and the necessary ancillary equipment for the storage containers. During November 2001, the contract was supplemented to authorize HI to perform the same services at BFN. TVA employee Mr. Symonds was involved in the negotiations for the BFN contract as the BFN Technical Contract Manager, while being courted by HI with promises of money and employment. Mr. Symonds was later paid over $50,000 for his assistance in obtaining the TVA contract for HI.

FINDINGS

While TVA was assessing re-racking spent nuclear fuel storage at BFN, the plant initiated a study to determine if BFN should convert to a dry cask storage system instead of re-racking its spent nuclear fuel. Mr. Symonds began advocating strongly for HI to perform the work at BFN that HI had performed at SQN. During this time, (b) (7)(C) agreed to pay Mr. Symonds $50,000. (b) (7)(C) suggested that Mr. Symonds create a company and took Mr. Symonds to HI's (b) (7)(C) [redacted], who provided Mr. Symonds with a contact which would help Mr. Symonds establish an Limited Liability Company (LLC) in Delaware.

From July 29 to August 2, 2001, Mr. Symonds and his wife went to Philadelphia, Pennsylvania, on a birthday trip. The itinerary for the trip was arranged by HI and the round-trip airline reservation for Mr. Symonds and his wife was made and paid for by HI. From Philadelphia, Mr. Symonds and his wife traveled to Atlantic City, New Jersey, and stayed at the Taj Mahal, the Trump-owned hotel, paid for by HI. Mr. Symonds and his wife had dinner with (b) (7)(C) [redacted] that night. On July 31, 2001, they returned to Philadelphia where HI had made reservations for the Symonds at the Rittenhouse Hotel. (b) (7)(C) arranged for a dinner party for the Symonds at a fine French restaurant, Le Bec-Fin, and HI paid $2,137.20 for the meal. Attending were Mr. Symonds and his wife, (b) (7)(C) and his wife, and three HI executives and their escorts. (b) (7)(C) placed Mr. Symonds at the head of the table.

Later in August, 2001, (b) (7)(C) and Mr. Symonds attended a meeting at Fitzpatrick Power Plant, Oswego, New York, consisting of about 30 people representing various utilities to discuss lessons learned. Mr. Symonds was reimbursed a portion of the cost for this trip by TVA, and travel expenses were also charged to UST&D of which (b) (7)(C) was the majority owner. A Confidential Source recalled that (b) (7)(C) and (b) (7)(C) created a company, FABSCO Inc., and that company controlled UST&D (see Attachment 1). While Mr. Symonds was at the meeting, a TVA employee telephoned Mr. Symonds to tell him the TVA Board decided to proceed with the dry

cask storage project for BFN. During a dinner that night, (b) (7)(C) announced with fanfare to everyone present the decision to award the BFN work to HI, to the celebratory sound of clinking glasses. During the dinner, Mr. Symonds' wife told (b) (7)(C) her vocation was credentialing doctors, which included conducting physicians' background checks.

On September 13, 2001, Mr. Symonds had a breakfast meeting with (b) (7)(C) at the Marriott Hotel, Huntsville, Alabama. Previously, (b) (7)(C) had discussed employment for Mr. Symonds with HI. During this meeting, (b) (7)(C) expressed concern, to avoid appearance problems, that Mr. Symonds not come to work at HI directly from TVA. Mr. Symonds would manage a construction company that appeared to be a separate entity from HI. (b) (7)(C) offered Mr. Symonds a vice-president position at HI with a salary of $175,000 per year plus one percent of the business. (b) (7)(C) suggested January 1, 2002, as the target date for Mr. Symonds to report to work at HI. Mr. Symonds considered himself a part of HI from that point on, even though he continued to work for TVA. (b) (7)(C) told Mr. Symonds they could set up a way to pay Mr. Symonds $50,000 by setting up a business through Mr. Symonds' wife for background investigation services.

During November 2001, the HI dry cask contract for SQN was supplemented to authorize HI to perform the same services at BFN. Mr. Symonds had been involved in the negotiations for the BFN contract as the BFN Technical Contract Manager.

Also in November 2001, Mr. Symonds established Krohn Enterprises, an LLC in Delaware. On December 13, 2001, a post office box was created for Krohn Enterprises, in Huntsville, Alabama, and the name "Jack Symonds" was included as a person with access to the box. A bank account was also created in the name of Krohn Enterprises. Mr. Symonds came up with the name Krohn by using the first two letters of (b) (7)(C) first name, (b) (7) and the last three letters of his own name, (b) (7)(C)

Further, in November 2001, Mr. Symonds and his wife made a house-hunting trip to Philadelphia, Pennsylvania. The trip was later reimbursed by (b) (7)(C) through UST&D. During this trip, (b) (7)(C) moved Mr. Symonds' employment date from January to April 2002.

Shortly after the meeting in November, Mr. Symonds and (b) (7)(C) met at a restaurant in Cherry Hill, New Jersey. (b) (7)(C) said he did not know if they were going to bring Mr. Symonds in to HI as a vice president, and said Mr. Symonds might be worth more to (b) (7)(C) by remaining at BFN during the Unit 1 restart. (b) (7)(C) then said he would pay Mr. Symonds an additional $100,000.

Subsequently, (b) (7)(C) instructed UST&D to make a payment of $50,000 to an agency that would be billing UST&D for background checks. No investigative services were rendered to UST&D, and none were provided by Krohn Enterprises. Krohn Enterprises submitted two invoices to UST&D (Attachment 2). The first invoice, dated January 15, 2002, totaled $29,212.77 and included the first "retainer" payment of $25,000 and $4,212.77 in travel expenses. The travel expenses invoiced to UST&D were for the travel expenses of Mr. Symonds' meetings with (b) (7)(C) and HI officials. The second invoice, dated February 5, 2002, was for a "retainer fee," payment of $25,000. UST&D paid Krohn Enterprises a total of $54,212.77. A review was conducted of documents obtained by the Office of the Inspector General (OIG) regarding travel by Mr. Symonds and a copy of the review is attached (Attachment 3).

In approximately January 2002, Mr. Symonds learned from TVA employee (b) (7)(C) , who replaced Mr. Symonds as the Technical Contract Manager for the HI contract, that (b) (7)(C) had been offered a job by (b) (7)(C) Mr. Symonds did not miss the fact that he was now being ignored by (b) (7)(C) while (b) (7)(C) was pitching (b) (7)(C) to work for him. Mr. Symonds prepared a letter (Attachment 4) and sent it to (b) (7)(C) as a last chance for a position with HI, although it was clear to Mr. Symonds that his job with HI was dead.

STATEMENTS BY KRISHNA SINGH

On October 12, 2006, Mr. Symonds consented to telephoning (b) (7)(C) for the purpose of recording the conversation. Mr. Symonds told (b) (7)(C) the OIG was aware of the money paid to Mr. Symonds by UST&D and was coming to interview Mr. Symonds. Mr. Symonds requested advice from (b) (7)(C) on how to handle the situation. (b) (7)(C) response was as follows:

> *Well, you know UST&D had hired your wife to do security checks. She got paid for that, right? That was the retainer paid to do the work. She did do retainer work. Why are they auditing your account? There's no, there's nothing that uh, I mean it was a clean transaction, she was in the business of checking out, you know we had some, to my knowledge, UST&D had some problems with thefts and stuff, otherwise it was checks. She paid for, you know they paid for it. But you didn't do any direct business with UST&D, did you? They won't call me because I have nothing to do with it, you know. But to the extent that I pointed to a potential source for UST&D to get the help, they ask me I'll tell them. You know, I'll tell them the straight scoop. Jack you ought to make sure that you tell them that you really have no, the funds you don't know anything about the fact, other than the fact that your wife was in the business of doing consulting services and it was payment retainer for that work, and it's a company that you don't do any business with, and you have not.*

A copy of the entire transcription is attached (Attachment 5).

A few minutes after the recording above was made, (b) (7)(C) was interviewed in his office by OIG Special Agents. During that interview (b) (7)(C) stated essentially the following.

- Sometime between 1999 and 2001, UST&D was having problems with employee thefts. He wasn't sure if it was parts being stolen or other materials, but there was a problem. (b) (7)(C) advised that he mentioned to someone that Mr. Symonds did security checks. He wasn't sure if it was Mr. Symonds, his partner or someone associated with Mr. Symonds that helped companies catch employees stealing. (b) (7)(C) may have mentioned the theft problems to Mr. Symonds and suggested Mr. Symonds call the plant manager or he may have mentioned it to plant personnel to contact Mr. Symonds, he just couldn't remember. (b) (7)(C) thought he may have put Mr. Symonds in touch with several other people. (b) (7)(C) said he could not give the specifics about how he knew Mr. Symonds was involved with catching employees stealing at factories. (b) (7)(C) did not know if UST&D used Mr. Symonds or not.

- (b) (7)(C) recalled Mr. Symonds visited HI on a couple of occasions when Mr. Symonds was on a project they were doing at BFN. If Mr. Symonds came to HI, he (b) (7)(C) would have seen him. He never requested that HI employees entertain Mr. Symonds. However, he did know that Mr. Symonds was friendly with one of HI's engineers who no longer worked for HI. (b) (7)(C) was asked if he provided any entertainment to Mr. Symonds and (b) (7)(C) said he remembered having dinner with Mr. Symonds on one occasion. He does not remember who paid for the meal but he normally offered to pay for any meal he had with someone and they normally obliged. Sometimes clients would send checks back to him for the cost of their meals. He did not recall the specifics about the meal with Mr. Symonds.

- (b) (7)(C) stated that he would not have offered any money to Mr. Symonds or Krohn Enterprises for any reason. He did not direct anyone to pay any money to Mr. Symonds or Krohn Enterprises for any reason. He did not think that Mr. Symonds would solicit money from him. He said he has a particular air about him, and no one would ask a cent from him. (b) (7)(C) said that he was a very ethical person in business dealings. (b) (7)(C) stated he could not say if someone at HI or UST&D paid Mr. Symonds, but he has never been told anything or that anyone paid Krohn Enterprises anything. (b) (7)(C) opined that Mr. Symonds was not in a position to award contracts for TVA.

OTHER BAD ACTS BY (b) (7)(C)

(b) (7)(D), Exelon Corporation provided documentation relating to an internal investigation concerning an engineer in a position to potentially influence a contract award to HI and whose wife had a business with which HI began doing business under (b) (7)(C) direction. That investigation was instituted upon the receipt of information that HI, a contractor involved in a $20,000,000 project with ComEd, an Exelon company, for dry cask storage products, had switched travel agencies and began using an agency in Northbrook, Illinois, called Cove Travel. That travel agency was allegedly owned by (b) (7)(C), a Senior Engineer at ComEd Corporate Services, who was involved in administering the project with HI. According to a ComEd Supervising Engineer, in mid-July 1997, while on an audit trip to Japan, a HI Quality Assurance Manager, stated (b) (7)(C) had sent a letter to all HI employees instructing all travel arrangements be made through a travel agency in Northbrook. This letter was followed up six months later by (b) (7)(C) diverting all travel arrangements to (b) (7)(C)). During the internal investigation (b) (7)(C) was interviewed concerning the matter and stated he had known (b) (7)(C) since late 1989 or early 1990. (b) (7)(C) was sure that (b) (7)(C) made the initial contact with him relative to Cove Travel. She then submitted a proposal which he turned over to one of the two HI personnel who handled travel arrangements for the firm. He advised that (b) (7)(C) had never put pressure on him to use Cove Travel and had never told him he would increase/decrease ComEds business with HI dependent upon the use of Cove Travel. Were this to happen, (b) (7)(C) would "kick him out," stating in his mind, for one thing, (b) (7)(C) had "zero" authority to place business and had no "clout."

(b) (7)(C) WRITES TO INSPECTOR GENERAL AND CHIEF NUCLEAR OFFICER

(b) (7)(C) sent a letter addressed to the TVA Inspector General, Richard W. Moore, dated November 17, 2006 (Attachment 6), during the timeframe the criminal investigations were ongoing concerning HI, (b) (7)(C) and Mr. Symonds. In that letter (b) (7)(C) stated, "Holtec International categorically asserts that the company has not provided any funds to Mr. Saimonds [sic] in any shape or form, indirectly or directly."

(b) (7)(C) also e-mailed a letter to Karl Singer, then Chief Nuclear Officer and Executive Vice President, dated November 9, 2006 (Attachment 7). In that letter, (b) (7)(C) stated, in part, "… we do not know anything about the gentleman's (Symonds') interactions with UST&D."

CONTRACT REVIEW

The OIG conducted a review of the TVA contract with HI for the purchase of dry cask storage systems for spent nuclear fuel at SQN and BFN. The purpose of the review was to assess the reasonableness of the prices TVA paid HI for certain high-dollar equipment items at BFN in comparison with the prices paid for the equipment at SQN. Specifically, the OIG reviewed the prices TVA paid HI for the four largest dollar-value cask system components: the MPC (multipurpose canister for spent fuel), HI-STORM 100 (long-term storage overpack for the MPC), HI-TRAC 125D (in-plant transfer overpack for the MPC), and the vertical crawler. TVA had paid $7,198,763 for the equipment at SQN, versus $9,186,120 at BFN, a difference of $1,987,357.

Information obtained in the review (Attachment 8) found HI may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, the review found that HI had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. The price HI quoted for the BFN crawler misrepresented its compliance with the contract.

It appeared TVA relied on the information provided by HI to justify paying the higher BFN prices rather than attempting to negotiate lower pricing for BFN. Although it is unknown if TVA could have successfully negotiated lower prices for BFN, key economic indicators and reduction in material prices between the time period when HI proposed the SQN and BFN prices indicate TVA had an opportunity to negotiate better prices. For example, the price of steel had fallen about seven percent during the period between the SQN proposal and the BFN proposal.

In summary, the OIG review found evidence that the higher prices TVA agreed to pay for the BFN MPC, the HI-STORM 100 and the HI-TRAC 125D were unreasonable. It appears HI may have misled TVA regarding its pricing and TVA did not attempt to negotiate better prices at BFN.

RECOMMENDATIONS

We recommend TVA place HI on the Supply Chain Clearance List based on the actions of (b) (7)(C) [redacted]. In addition, if you decide to take other documented action on the basis of this report, we would appreciate your sending a copy of the relevant information to this office for our file.

We would appreciate being informed within 15 days of your determination of what action is appropriate on the basis of our report. Our investigative files will be made available for review upon request.

William R. McCollum, Jr.
Ralph E. Rodgers
Page 8
March 23, 2010

This report has been designated "TVA Restricted" in accordance with TVA Business Practice 29, Information Security. Accordingly, it should not be disclosed further without the prior approval of the Inspector General or his designee. In addition, no redacted version of this report should be distributed without notification to the Inspector General of the redactions that have been made.

Our investigation of this matter is closed.

John E. Brennan
Assistant Inspector General
(Investigations)
ET 4C-K

(b) (6) [redacted]
cc: Terrell M. Burkhart, WT 3A-K
Maureen H. Dunn, WT 6A-K
Peyton T. Hairston, Jr., WT 7B-K
Tom D. Kilgore, WT 7B-K
Kenneth E. Tilley, WT 3A-K
OIG File No. 12E-102

Attachment 1
Page 1 of 11

PENNSYLVANIA DEPARTMENT OF STATE
CORPORATION BUREAU

Articles of Incorporation-For Profit
(15 Pa.C.S.)

Entity Number

- [X] Business-stock (§ 1306)
- [ ] Business-nonstock (§ 2102)
- [ ] Business-statutory close (§ 2303)
- [ ] Cooperative (§ 7102)
- [ ] Management (§ 2703)
- [ ] Professional (§ 2903)
- [ ] Insurance (§ 3101)

Name: M. BURR KEIM COMPANY
Address: 2021 Arch Street
City / State / Zip Code: Philadelphia, PA 19103

Document will be returned to the name and address you enter to the left.

Fee: $100

Filed in the Department of State on JUL 25 2002

Secretary of the Commonwealth

In compliance with the requirements of the applicable provisions (relating to corporations and unincorporated associations), the undersigned, desiring to incorporate a corporation for profit, hereby states that:

1. The name of the corporation *(corporate designator required, i.e., "corporation", "incorporated", "limited" "company" or any abbreviation. "Professional corporation" or "P.C")*:

FABSCO, Inc.

2. The (a) address of this corporation's current registered office in this Commonwealth *(post office box, alone, is not acceptable)* or (b) name of its commercial registered office provider and the county of venue is:

(a) Number and Street	City	State	Zip	County
1800 One Liberty Place c/o White and Williams LLP	Philadelphia	PA	19103	Philadelphia

Attention: G. P. Biehn, Esq.
(b) Name of Commercial Registered Office Provider — County

c/o

3. The corporation is incorporated under the provisions of the Business Corporation Law of 1988.

4. The aggregate number of shares authorized: 10,000 shares common

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Page 2 of 11

2002066 890

DSCB:15-1306,2102/2303/2702/2903/3101/7102A-2

5. The name and address, including number and street, if any, of each incorporator *(all incorporators must sign below)*:

Name	Address
Susan J. Kadin	White and Williams LLP
	1800 One Liberty Place
	Philadelphia, PA 19103

6. The specified effective date, if any: Upon filing
month/day/year hour, if any

7. Additional provisions of the articles, if any, attach an 8½ by 11 sheet.

8. ~~*Statutory close corporation only.* Neither the corporation nor any shareholder shall authorize offering of any of its shares of any class that would constitute a public offering within the meaning of the Securities Act of 1933 (15 U.S.C. 77a et seq.)~~

9. ~~*Cooperative corporations only. Complete and strike out inapplicable term:*~~

~~The common bond of membership among its members/shareholders is:~~

IN TESTIMONY WHEREOF, the incorporator(s) has/have signed these Articles of Incorporation to be signed by a duly authorized officer thereof this

25th day of July 2002

Signature
Susan J. Kadin, Incorporator

Signature

2002066- 801

ARTICLES OF INCORPORATION

FABSCO, INC.

Additional Provisions

7(a). Shareholders shall not have cumulative voting rights in the election of directors.

7(b). The term of the corporation is perpetual.

Doc#: 105395 v5

Attachment 1
Page 4 of 11

FROM WHITE & WILLIAMS 200207 1- 971

PENNSYLVANIA DEPARTMENT OF STATE
CORPORATION BUREAU

Articles/Certificate of Merger
(15 Pa.C.S.)

Entry Number
811235

[X] Domestic Business Corporation (§ 1926)
[ ] Domestic Nonprofit Corporation (§ 5926)
[ ] Limited Partnership (§ 8547)

Name
Address CT CORP-COUNTER
City State Zip Code

Document will be returned to the name and address you enter to the left.

Fee: $108 plus $28 additional for each Party in additional to two

Filed in the Department of State on AUG 16 2002

C. Michael Pressler
Secretary of the Commonwealth

In compliance with the requirements of the applicable provisions (relating to articles of merger or consolidation), the undersigned, desiring to effect a merger, hereby state that:

1. The name of the corporation/limited partnership surviving the merger is
L. S. Tool & Die, Inc.

2. Check and complete one of the following

[X] The surviving corporation/limited partnership is a domestic business/nonprofit corporation/limited partnership and the (a) address of its current registered office in this Commonwealth or (b) name of its commercial registered office provider and the county of venue is (the Department is hereby authorized to correct the following information to conform to the records of the Department):

(a) Number and Street	City	State	Zip	County
Keystone Commons, 200 Braddock Ave	Turtle Creek	PA	15145	Allegheny

(b) Name of Commercial Registered Office Provider | County

[ ] The surviving corporation/limited partnership is a qualified foreign business/nonprofit corporation/limited partnership incorporated/formed under the laws of ____ and the (a) address of its current registered office in this Commonwealth or (b) name of its commercial registered office provider and the county of venue is (the Department is hereby authorized to correct the following information to conform to the records of the Department):

(a) Number and Street | City | State | Zip | County

(b) Name of Commercial Registered Office Provider | County

[ ] The surviving corporation/limited partnership is a qualified foreign business/nonprofit corporation/limited partnership incorporated/formed under the laws of ____ and the address of its principal office under the laws of such domiciliary jurisdiction is:

Number and Street | City | State | Zip

DCB 15-1926 5926/8547-2

Attachment 1
Page 5 of 11

FROM WHITE & WILLIAMS LLP

200207 1- 972

3 The name and the address of the registered office in this Commonwealth or name of its commercial registered office provider and the county of venue of each other domestic business/nonprofit corporation/limited partnership and qualified foreign business/nonprofit corporation/limited partnership which is a party to the plan of merger are as follows

Name	Registered Office Address	Commercial Registered Office Provider	County
FABSCO, INC	1500 ONE LIBERTY PLACE, PHILADELPHIA, PA 19103		PHILADELPHIA

4 *Check and if appropriate complete one of the following*

[X] The plan of merger shall be effective upon filing these Articles/Certificate of Merger in the Department of State

[ ] The plan of merger shall be effective on _____ at _____
Date Hour

5 The manner in which the plan of merger was adopted by each domestic corporation/limited partnership is as follows

Name	Manner of Adoption
FABSCO, Inc	Board of Directors pursuant to PA BCL1924(b)(1)(ii) & 1924 (b)(3)

6 ~~*Strike out this paragraph if no foreign corporation/limited partnership is a party to the merger*~~
~~The plan was authorized, adopted or approved, as the case may be, by the foreign business/nonprofit corporation/limited partnership (for each of the foreign business/nonprofit corporations/limited partnerships) party to the plan in accordance with the laws of the jurisdiction in which it is incorporated/organized~~

7 *Check and if appropriate complete one of the following*

[X] The plan of merger is set forth in full in Exhibit A attached hereto and made a part hereof

[ ] Pursuant to 15 Pa C.S. § 1907 (§ 5947(a) relating to omission of certain provisions from filed plans) the provisions if any, of the plan of merger that amend or constitute the operative provisions of the Articles of Incorporation/Certificate of Limited Partnership of the surviving corporation/limited partnership as in effect subsequent to the effective date of the plan are set forth in full in Exhibit A attached hereto and made a party hereof. The full text of the plan of merger is on file at the principal place of business of the surviving corporation/limited partnership, the address of which is

Number and street	City	State	Zip	County

Atachment 1
Page 6 of 11

FROM WHITE & WILLIAMS LLP

2002071-973

IN TESTIMONY WHEREOF, the undersigned corporation/limited partnership has caused these Articles/Certificate of Merger to be signed by a duly authorized officer thereof this

14th day of August,

2002.

FABSCO, Inc

Name of Corporation/Limited Partnership

David S. Ferman

Signature

David S. Ferman, President

Title

Name of Corporation/Limited Partnership

Signature

Title

FROM WHITE & WILLIAMS LLP
2002071- 974

Exhibit A

Plan of Merger

This Plan of Merger ("Plan") between FABSCO, Inc., a Pennsylvania corporation ("Parent"), and U S Tool & Die, Inc., a Pennsylvania corporation ("Subsidiary") shall be adopted by Parent in the manner and become effective as of the time provided below.

1. Background. Parent is record and beneficial owner of 82.47% of the issued and outstanding capital stock of Subsidiary ("Subsidiary Common Stock"). The remaining shares of the Subsidiary Common Stock are owned and held of record by those shareholders listed in the Subsidiary's corporate records as of the Plan Adoption Date (as such term is defined in Section 2 of this Plan). The Board of Directors of Parent has determined that is desirable and in the best interests of Parent and Subsidiary that Parent be merged with and into the Subsidiary on the terms and conditions set forth in this Plan and in accordance with the applicable provisions of the Pennsylvania Business Corporation Law of 1988, as amended (the "PA BCL").

2. Approval. This Plan shall become adopted ("Plan Adoption Date") upon its approval by the Board of Directors of the Parent in accordance with Sections 1922(c), 1924(b)(1)(ii), and 1924(b)(3) of the PA BCL.

3. Time and Effect of Merger.

(a) *Effective Time*. The Merger shall become effective at the close of business on the date upon which appropriate Articles of Merger (to which this Plan will be attached and incorporated therein) are filed with the Department of State of the Commonwealth of Pennsylvania ("Merger Effective Time").

(b) *Effects of Merger*. At the Merger Effective Time, Parent shall merge with and into Subsidiary, the separate existence of Parent shall cease, and Subsidiary shall be the surviving corporation (the "Surviving Corporation"), all in accordance with this Plan and the applicable provisions of the PA BCL (the "Merger"). At the Merger Effective Time and as a result of the Merger, the Surviving Corporation shall continue to exist as a domestic business corporation under the laws of the Commonwealth of Pennsylvania with all of the rights and obligations of such surviving domestic business corporation as are provided by Section 1929 and the other applicable provisions of the PA BCL. Without limiting the generality of the foregoing, as of the Merger Effective Time, all of the property (real, personal and mixed), rights, powers, privileges, immunities, licenses, permits and franchises (both of a

Attachment 1
Page 8 of 11

private and public nature), and restrictions, duties, and obligations of the Parent and Subsidiary shall be taken and be deemed to be transferred to and vested or continued to be vested, as the case may be, in the Surviving Corporation, without further act, agreement, approval or deed.

4. Articles of Incorporation; Bylaws. The Articles of Incorporation and Bylaws of the Subsidiary as in effect prior to the Merger Effective Time shall remain the same and continue unchanged as, respectively, the Articles of Incorporation and Bylaws of the Surviving Corporation on and after the Merger Effective Time until changed in accordance with their respective terms and the applicable provisions of the PA BCL.

5. Directors and Officers. The Officers of Subsidiary prior to the Merger Effective Time shall, as of the Merger Effective Time, be and remain, respectively, the Officers of the Surviving Corporation until their respective successors are duly elected and qualified under the Bylaws of the Surviving Corporation then in effect, or until their earlier death or until their resignation or removal in accordance with such Bylaws. As of the Effective Time, the Directors of the Surviving Corporation shall be David S. Forman, Robert L. Moscardini and Christopher P. Strock who will serve as Directors of the Surviving Corporation until their respective successors are duly elected and qualified under the Bylaws of the Surviving Corporation then in effect, or until their earlier death or resignation or removal in accordance with such Bylaws.

6. Conversion of Shares.

(a) *Conversion of Shares of Subsidiary*. Subject to the provisions of Sections 7 and 8 of this Plan, except for Dissenting Shares (as such term is defined in Section 10 of this Plan), which at the Merger Effective Time shall be converted into the right to receive the consideration determined in accordance with Section 10 of this Plan and the applicable provisions of the PA BCL, each share of Subsidiary Common Stock shall, at the Merger Effective Time, without further action and by virtue of the Merger, be converted into the right to receive cash consideration in the amount of $ .75 for each share of Subsidiary Common Stock, payable in accordance with Sections 7 and 8 of this Plan, and shall no longer be outstanding and shall be deemed to be automatically canceled and cease to exist.

(b) *Conversion of Shares of Parent*. Subject to the provisions of Section 8 of this Plan, each share of capital stock of Parent ("Parent Shares") shall, at the Merger Effective Time, without further action and by virtue of the Merger, be converted into one (1) share of capital stock of the Surviving Corporation, and shall no longer be outstanding and shall be deemed to be automatically canceled and cease to exist.

7. Withholding Rights. The Surviving Corporation shall be entitled to deduct and withhold from the consideration otherwise payable under Section 6 or 10 of this Plan, as the case may be, such amounts, if any, as it is required to deduct, withhold, and remit with

200207 1- 976

respect to the making of such payment under any provision of federal, state or local tax law (a "Withholding"). Any such Withholding shall be treated for all purposes (including without limitation this Plan and the Merger) as having been paid to the Record Shareholder (as such term is defined in Section 8) in respect of which the Surviving Corporation made such Withholding and, notwithstanding anything contained to the contrary in this Plan, such Record Shareholder shall only be entitled to receive from the Surviving Corporation the consideration payable pursuant to this Plan and/or the Dissenters' Rights Provisions (as such term is defined in Section 10 of this Plan), less any Withholding, which shall be payable on such Record Shareholder's account to the applicable federal, state or local taxing authority in accordance with applicable federal, state or local tax law ("Net Merger Consideration").

8 Notice; Surrender and Payment; Rights in Subsidiary Common Stock; Etc.

(a) *Merger Notice*. As soon as practicable following the Merger Effective Time, the Surviving Corporation shall mail or cause to be mailed to each record holder or record owner, as the case may be (individually, a "Record Shareholder" and collectively the "Record Shareholders") of the shares of Subsidiary Common Stock on the Plan Adoption Date notices ("Merger Notice") advising them of and enclosing, as applicable: (i) the effectiveness of the Merger, (ii) a copy of this Plan; (iii) a form letter of transmittal and instructions regarding the surrender of their certificates formerly representing shares of Subsidiary Common Stock ("Subsidiary Certificates"), or in lieu thereof, such evidence of lost, stolen or destroyed certificate(s) and such surety bonds or other security as the Surviving Corporation may, in its discretion, require ("Required Documentation"), in exchange for the applicable Net Merger Consideration, and (iv) the notices, information and other materials required to be provided to the Record Shareholders under Section 1575 of the PA BCL.

(b) *Surrender of Subsidiary Certificates; Payment of Consideration*. After the Merger Effective Time, upon surrender of their Subsidiary Certificates, or in lieu thereof, the Required Documentation, to the Surviving Corporation with a properly completed and executed letter of transmittal (substantially in the form included in the Merger Notice) with respect to such certificates, a Record Shareholder will be entitled to receive the applicable Net Merger Consideration. Such consideration shall be delivered by the Surviving Corporation as promptly as practicable after such surrender. Except as otherwise expressly provided in Section 10 of this Plan, without the written consent of a Record Shareholder and such other documentation and other items as the Surviving Corporation in its discretion may require (a "Permitted Substitution"), no person other than a Record Shareholder shall be entitled to receive any consideration whatsoever from the Surviving Corporation as a result of the Merger. In the event of a Permitted Substitution, except in respect of the availability of Dissenters' Rights (as such term is defined in Section 10)), which shall be determined in accordance with Section 10 of this Plan, such person shall be considered a Record Shareholder for purposes of this Plan and the Record Shareholder for which a Permitted Substitution was

made shall thereafter have no right to receive any consideration from the Surviving Corporation as a result of the Merger.

(c) *Rights in Subsidiary Common Stock Following Merger*. As of the Merger Effective Time, (i) the Record Shareholders, all other holders of Subsidiary Certificates, and all beneficial but not record owners of Subsidiary Common Stock prior to the Merger Effective Time, if any, shall cease to have rights with respect to such previously outstanding stock, provided, however that the Record Shareholders only shall have the right to either exchange his, her or its Subsidiary Certificates or Required Documentation, as the case may be, for the Net Merger Consideration to which such Record Shareholder may be entitled pursuant to Sections 6 and 7 of this Plan or elect their Dissenters' Rights in accordance with the Dissenters' Rights Provisions (as such terms are defined in Section 10 of this Plan), and (ii) the Subsidiary Certificates held by Record Shareholders shall be deemed to evidence only ownership of either such Net Merger Consideration or Dissenters' Rights in respect of such Subsidiary Common Stock, if so elected in accordance with the Dissenters' Rights Provisions. In no event shall the Surviving Corporation be obligated to deliver Net Merger Consideration set forth in Sections 6 and 7 or determined pursuant to Section 7 and the Dissenters' Rights Provisions to a Record Shareholder unless and until such Record Shareholder surrenders his, her or its Subsidiary Certificates or furnishes the Required Documentation, as the case may be.

(d) *Surrender of Parent Shares Certificates; Issuance of Surviving Corporation Stock*. Upon receipt by the Surviving Corporation of the certificates representing the Parent Shares or in lieu thereof Required Documentation, as the case may be, together with a properly completed and executed letter of transmittal (in the form acceptable to the Surviving Corporation) with respect to such certificates, the Surviving Corporation will issue to the Parent's shareholders certificates representing the same number of shares of capital stock of the Surviving Corporation as had been held by them in the Parent immediately prior to the Merger Effective Time.

9. Termination of Plan. This Plan may be terminated and the Merger abandoned by action of the Board of Directors of Parent at any time before the Merger Effective Time.

10. Dissenters' Rights. Each (i) Record Shareholder or (ii) subject to compliance with the provisions of Section 1573 of the PA BCL, beneficial owner of Subsidiary Common Stock that is not a Record Shareholder (either, a "Dissenter"), as the case may be, shall be entitled to exercise dissenters' rights ("Dissenters' Rights") with respect to his, her or its shares of Subsidiary Common Stock ("Dissenting Shares") as a result of the Merger, as provided in Sections 1930(a), and 1571 and the other applicable sections of the PA BCL ("Dissenters' Rights Provisions"). Notwithstanding the foregoing, a Dissenter shall forfeit his, her or its Dissenters' Rights, unless such Dissenter makes a demand pursuant to the provisions of Section 1575 of the PA BCL at the time and place specified in the Merger Notice with respect to such shares (a "Perfected Dissenter"). A Perfected Dissenter will be entitled,

subject to compliance with Section 8 of this Plan, to the fair value (less any Withholdings) for his, her or its Dissenting Shares, which fair value will be determined in accordance with Sections 1578 and/or 1579 of the PA BCL, as applicable, and will have such other rights and be subject to such obligations as are accorded to or imposed upon him, her or it pursuant to the Dissenters' Rights Provisions; provided, however, that if a Perfected Dissenter shall subsequently deliver a written withdrawal of his, her or its demand for appraisal of such shares (with the written approval of the Surviving Corporation), then such person shall also forfeit his, her or its Dissenters' Rights. In the event that a Dissenter forfeits his, her or its Dissenters' Rights, then such shares shall thereupon be deemed to have been converted into and to have become exchangeable for, as of the Merger Effective Time, subject to the provisions of Section 8 of this Plan, the right to receive his, her or its Net Merger Consideration provided in Sections 6(a) and 7 of this Plan without any interest or other additional sums payable thereon.

11. Amendment. This Plan may be amended in any manner at any time before the Merger Effective Time by action of the Board of Directors of Parent, subject to compliance with Section 1922(b) of the PA BCL.

The Parent has adopted this Plan as of August 17, 2002.

Attachment 2
Page 1 of 2

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5399

INVOICE

DATE: January 15, 2002
INVOICE # 0001
RE: P.O. 01-12145

Bill To:
US Tool & Die
200 Braddock Avenue
Turtle Creek, PA 15145

For:
Retainer (1/2)
Expenses to Date

DESCRIPTION			AMOUNT
Retainer (½ 1st payment)			25,000.00
Airline Tickets			2,473.50
Hotel			1113.83
Car Rental			413.28
Fuel			39.00
Meals			104.16
Tolls			21.00
Parking			48.00
		TOTAL	$29,212.77

Make all checks payable to **Krohn Enterprises**
Payable upon receipt.

Attachment 2
Page 2 of 2

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5399/5400

INVOIC

DATE: February 15, 2002
INVOICE # 0002
RE: P.O. 01-12145

Bill To:
US Tool & Die
200 Braddock Avenue
Turtle Creek, PA 15145

For:
Retainer (1/2)

DESCRIPTION			AMOUNT
Retainer (½ 2nd payment)			25,000.00
		TOTAL	$25,000.00

Make all checks payable to **Krohn Enterprises**
Payable upon receipt.

Jack Symonds Travel Analysis
Case 12E-100

The following investigation was conducted by Intelligence Analyst [redacted] (b) (7)(C) on August 10, 2006, in Knoxville, TN.

Jul 29-Aug 2, 2001
During the period of 7/29/01 – 8/2/01, Symonds and [redacted] (b) (7)(C) flew to Philadelphia, PA not on duty status. The hotel is suspected to have been paid for by Holtec. TVA was direct-billed for the rental car because Symonds used his government travel card for the rental. TVA was not reimbursed by Symonds. (Title 18, Sec 287).

July 29 – August 2, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Locations: Atlantic City, NY Philadelphia, PA	Flight	-	-	Unknown
	Hotel	-	-	$1,176.70
	Rental Car	$244.75	-	Unknown
	Meals	-	-	Unknown
	Gas	-	-	Unknown
On Leave from TVA	Miscellaneous	-	-	Unknown
	Total	$244.75	$0	$1,176.70

Aug 20 - 26, 2001
During the period of 8/20/01 – 8/26/01, Symonds and [redacted] (b) (7)(C) flew to Syracuse, NY. Symonds' status was on-duty and TVA paid his travel expenses. Subsequently, US Tool & Die also paid for some of his travel expenses through Krohn (Title 18, Sec 209 and 1001).

August 20 – 26, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Syracuse, NY	Expense Category	TVA	US Tool & Die	Holtec
Hotel Locations: Syracuse, NY New York, NY	Flight	$349.00	$349.00	-
	Hotel	$374.64	$374.64	-
	Rental Car	-	-	-
	Meals	$34.32	-	-
Not On Leave from TVA	Gas	-	-	-
	Miscellaneous	$186.20	-	-
	Total	$944.16	$723.64	$0

Jack Symonds Travel Analysis
Case 12E-100

Sep 6 - 7, 2001
During the period of 9/6/01 – 9/7/01, Symonds flew to Philadelphia, PA on duty status and TVA paid his travel expenses. Subsequently, US Tool & Die also paid for some of his travel expenses through Krohn Enterprises (Title 18, Sec 209).

September 6 – 7, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ	Flight	$232.50	-	-
	Hotel	$138.71	$138.85	-
	Rental Car	$84.55	$84.55	-
	Meals	$37.48	-	-
Not On Leave from TVA	Gas	-	-	-
	Miscellaneous	$74.58	-	-
	Total	$567.82	$223.40	$0

Sep 23 - 30, 2001
During the period of 9/23/01 – 9/30/01, Symonds and [redacted] flew to Allentown, PA, on leave status. TVA was direct-billed for Symonds' rental car because Symonds used his government travel card for the rental (Title 18, Sec 287).

September 23 – 30, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Allentown, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Unknown	Flight	-	$266.00	-
	Hotel	-	-	-
	Rental Car	$484.44	-	-
	Meals	-	-	-
On Leave from TVA	Gas	-	$21.80	-
	Miscellaneous	-	-	-
	Total	$484.44	$287.80	$0

Jack Symonds Travel Analysis
Case 12E-100

Oct 7 - 8, 2001
During the period of 10/7/01 – 10/8/01, Symonds flew to Philadelphia, PA during a holiday period. The cost of the flight was direct billed to TVA because Symonds used his government travel card to purchase the ticket, and US Tool & Die, through Krohn, also paid the cost (Title 18, Sec 287 and 1001).

October 7 – 8, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Philadelphia, PA	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ Federal Holiday	Flight	$264.50	$264.50	-
	Hotel	-	$144.56	-
	Rental Car	-	$50.09	-
	Meals	-	-	-
	Gas	-	-	-
	Miscellaneous	-	-	-
	Total	**$264.50**	**$459.15**	**$0**

Nov 9-12, 2001
During the period of 11/9/01 – 11/12/01, Symonds and two friends flew to Baltimore, MD. Symonds rented a car and drove to NJ over a weekend/holiday. Symonds submitted a travel voucher to TVA for reimbursement of expenses, and he also was reimbursed for his airline ticket, hotel, and the rental car by US Tool & Die through Krohn (Title 18, Sec 209 and/or 287).

November 9 – 12, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Baltimore, MD	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ Weekend/Federal Holiday	Flight	$177.50	$177.50	-
	Hotel	$314.82	$314.82	-
	Rental Car	$136.91	$136.91	-
	Meals	$62.04	$14.78	-
	Gas	-	$17.20	-
	Miscellaneous	$43.52	$27.00	-
	Total	**$734.79**	**$688.21**	**$0**

Attachment 3
Page 4 of 4

Jack Symonds Travel Analysis
Case 12E-100

Dec 6-7, 2001
During the period of 12/6/01 – 12/7/01, Symonds flew to Philadelphia, PA on duty status, rented a car and traveled to NJ. Symonds submitted a voucher to TVA for reimbursement of expenses and also was reimbursed by US Tool & Die through Krohn (Title 18, Sec 209 and 1001).

December 6 – 7, 2001		Company Paying Symonds' Travel Expenses		
Flight Location: Cherry Hill, NJ	Expense Category	TVA	US Tool & Die	Holtec
Hotel Location: Mount Laurel, NJ	Flight	$546.50	$546.50	-
	Hotel	$140.96	$140.96	-
	Rental Car	$102.13	$102.13	-
	Meals	$21.80	$21.74	-
Not On Leave from TVA	Gas	-	-	-
	Miscellaneous	$26.52	-	-
	Total	**$837.91**	**$811.33**	**$0**

Attachment 4
Page 1 of 2

KROHN ENTERPRISES
PO BOX 5324
HUNTSVILLE, AL
35814-5324
(256) 655-5400

[redacted]
Holtec International
Holtec Center
555 Lincoln Drive West
Marlton, NJ 08053

April 1, 2002

Dear [redacted]

It is becoming more and more difficult for you and I to engage in business conversations, although, through no fault of our own. I am also finding that I too am experiencing some of the paranoid feelings that you have previously expressed concern about. I have determined that the only way to truly communicate with you without fear of some kind of electronic eavesdropping or wiretapping or some other kind of industrial spying technique is to simply revert to a simpler time when writing a letter was the most effective way of communicating. I think that by exercising this medium we can eliminate the anxiety of worrying about what some other people might say or do about the perceptions.

Anyway, I wanted to let you know that the $50K we discussed back in September that was to be paid for activities through the end of the year 2001 has been satisfied. Now let's talk about the $100K that you said that you would pay me in 2002 to stay with TVA. I had originally sent you a proposal that we break that up into quarters which would be $25K in April, $25K in August, $25K in October and $25K in December. You did not respond to that proposal except to say that you wanted me to perform the original deal with Bob. Now that the original deal is satisfied and we are ¼ of the way through 2002, I think we should address how we are going to bill for the remaining $100K.

Krohn Inc. is alive and well and could very well prove to be the proper conduit for this transaction. [redacted] is still the CEO and all business transactions are done through her. If you want, she can send you an RFQ on Krohn Inc. letterhead explaining the billing for services rendered. You think about it and let me know how you want to handle the evolution.

I think that now that the ice has been broken with TVA on a couple of subjects, i.e., Engineering analysis activities with [redacted] and Feedwater Heater issues with [redacted] you should probably offer an unsolicited proposal to perform these kinds of activities. You should address the correspondence to [redacted] and copy [redacted]

(b) (6) [redacted] The only thing is, they might say "come on down and give us a presentation of what you think you can offer". We should be out of the outage by the 10th of April. The bad thing is we are going to do a mid-cycle outage on U2 for 2 identified fuel leakers the last week in April. It will only last a week (we hope). Then the board meets on May 16th to determine the fate of U1. So, if you lay this all out, it looks to me like your best chance at an audience with the decision makers between now and then would be the week of April 15th or the week of May 6th. Plan accordingly.

How is the construction company business search going? Have you told (b) (6) [redacted] (b) (6) [redacted] not to talk to me? (I thought you may have told them to pretend I didn't exist for a while until some time had passed). I keep trying to get a hold of them and I am not getting any response.

Let's stay in touch, so that we can eliminate any misunderstandings or any miscommunications that we promised each other we would avoid at all cost.

Talk to you later my friend,

Attachment 5
Page 1 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

Attachment 5
Page 2 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

Atachment 5
Page 3 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

Attachment 5
Page 4 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

Attachment 5
Page 5 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

(b) (7)(D)

[redacted]

(b) (7)(D)

[redacted]

(b) (7)(D)

[redacted]

Attachment 5
Page 9 of 12

(b) (7)(D)

[redacted]

TVA RESTRICTED INFORMATION

(b) (7)(D)

[redacted]

(b) (7)(D)

[redacted]

(b) (7)(D)

[redacted]

Attachment 6
Page 1 of 2

(b) (4)

TVA RESTRICTED INFORMATION

Attachment 6
Pag 2 of 2

(b) (4)

Attachment 7
Page 1 of 3

(b) (4), (b) (7)(C)

[redacted]

Atttachment 7
Page 2 of 3

(b) (4)

Atttachment 7
Page 3 of 3

(b) (4)

July 30, 2007

Charles A. Kandt, ET 4C-K

SPECIAL PROJECT 2007-11160 – HOLTEC INTERNATIONAL CONTRACT NO. 99999906 – REASONABLENESS OF PRICES TVA PAID FOR CERTAIN DRY CASK STORAGE SYSTEMS COMPONENTS AT BROWNS FERRY NUCLEAR PLANT

As requested by OIG Investigative Operations, we initiated an audit of Contract No. 99999906 that TVA has with Holtec International (Holtec) for the purchase of dry cask storage systems for spent nuclear fuel at Sequoyah Nuclear Plant (SQN) and Browns Ferry Nuclear Plant (BFN). The purpose of our review was to assess the reasonableness of the prices TVA paid Holtec for certain high dollar equipment items at BFN in comparison with the prices paid for the equipment at SQN. Specifically, as summarized in the following table, we reviewed the prices TVA paid Holtec for the four largest dollar-value cask system components: (1) the MPC (multipurpose canister for spent fuel); (2) HI-STORM 100 (long-term storage overpack for the MPC); (3) HI-TRAC 125D (in-plant transfer overpack for the MPC); and (4) the vertical crawler.

Summary of Price Differences for Major Components of Dry Cask Storage Systems

Description	SQN Price	BFN Price	Difference
MPC	(b) (4)		
HI-STORM 100			
HI-TRAC 125D			
Vertical Crawler			
Total			

Table 1

As discussed in detail below, information obtained in our audit found Holtec may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, we found that Holtec had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. In our opinion, the price Holtec quoted for the BFN crawler misrepresented its compliance with the contract.

CONTRACT BACKGROUND

On June 30, 2000, TVA entered into Contract No. 99999906 with Holtec to provide equipment and engineering services for a dry cask system to store SQN spent nuclear fuel.[1] On November 8, 2001, the contract was supplemented to include a similar dry cask system for BFN. As of June 20, 2007, the contract had been supplemented 37 times, and TVA had paid Holtec $31.2 million against the contract payment ceiling of $54 million. The contract term is currently set to expire on June 30, 2008.

[1] The original Contract No. P00NNQ-258310 was changed to No. 99999906 in July 2001 for conversion to the PassPort supply chain software.

The contract included fixed prices for most of the components of the cask system and for defined scopes of engineering tasks to address safety aspects of the cask system unique to the two plant sites. The contract also included cost-plus pricing for optional items including (1) construction of a storage pad for the casks at the plant site and (2) a vertical crawler heavy lifting device to move the casks from the plant to the on-site storage pad.

The OIG is investigating certain issues regarding the pricing TVA agreed to under the contract with Holtec. To support the investigation, an audit (Audit 2007-028C) of the contract was initiated to assess the reasonableness of the prices TVA paid Holtec for the four highest dollar cask system components as summarized in Table 1. To perform our review, we:

- Reviewed the contract and related supplements, correspondence, e-mails, and payment records obtained from TVA's files.
- Visited the SQN and BFN sites and interviewed the dry cask spent nuclear fuel project managers and other key personnel to obtain an understanding about the products purchased.
- Obtained copies of TVA's documentation of products received; Holtec's documentation packages for the MPC, HI-STORM 100, and HI-TRAC 125D units as required by the Nuclear Regulatory Commission for these safety-related items; and Holtec's specification document for each crawler, to more clearly define the products purchased.
- Visited Holtec's offices and reviewed cost information to obtain an understanding about Holtec's costs for the products delivered.
- Visited Lift System's (manufacturer of the vertical crawlers) offices and reviewed documentation of sales and related cost data for vertical crawlers sold to Holtec.

AUDIT FINDINGS AND CONCLUSIONS

Information obtained in our audit found Holtec may have made false statements regarding the equipment prices proposed to TVA, and it appeared TVA relied on that information to approve prices quoted for the BFN equipment. Additionally, we found that Holtec had overbilled TVA at least $276,000 for the BFN vertical crawler because it did not comply with the contract's cost-plus pricing provision. In our opinion, the price Holtec quoted for the BFN crawler misrepresented its compliance with the contract.

MPC, HI-STORM 100, and HI-TRAC 125D

Holtec's proposal (dated September 12, 2001) to add the BFN scope of work included significant price increases for the MPC, HI-STORM 100, and HI-TRAC 125D components in comparison to the prices TVA had agreed to pay for similar equipment at SQN. Our review of TVA and Holtec files found Holtec may have made false statements to TVA when it explained why the prices it had quoted for certain BFN components were higher than the SQN prices. Specifically, in a draft letter submitted to TVA, Holtec informed that:

- The HI-STORM 100 for BFN was a significantly improved model in comparison to the model proposed for use at SQN in that (1) it had a reduced height for transport through

the plant's external door, and (2) it reduced radiation exposure by about one rem per cask.

- The (lower) SQN price for the HI-TRAC 125D was the result of an arithmetic error during quoting.

Each of these statements appears to be false or at least misleading because:

(1) BFN's external door has an additional 4 feet of vertical clearance in comparison to SQN's, thus negating the need for a reduction in height for the BFN HI-STORM 100,

(2) We found no evidence that the proposed BFN HI-STORM 100 model would have had a significant reduction in radiation dose, and

(3) Holtec initially proposed a price for the SQN HI-TRAC 125D that was the same price subsequently proposed for BFN. The final SQN price resulted from a discount offered by Holtec late in the bidding process. Holtec's claim that the lower SQN price was the result of an arithmetic error rather than a discount may have created the illusion that its prices were not negotiable. (Note – Holtec's final letter transmitting a comparison of the prices did not include the statements from the draft about the HI-STORM 100. However, the letter continued to mislead the TVA negotiation team regarding SQN's low price for the HI-TRAC 125D, referring to it as "an estimating department error.")

It appeared TVA relied on the information provided by Holtec to justify paying the higher BFN prices rather than attempting to negotiate lower pricing for BFN. Although it is unknown if TVA could have successfully negotiated lower prices for BFN, key economic indicators and reductions in material prices between the time period when Holtec proposed the SQN and BFN prices indicate TVA had an opportunity to negotiate better prices. For example, the price of steel had fallen about 7 percent during the period between the SQN proposal and the BFN proposal.

In summary, we found no evidence that the higher prices TVA agreed to pay for the BFN MPC, HI-STORM 100, and HI-TRAC 125D were reasonable. Instead, it appeared (1) Holtec may have misled TVA regarding its pricing, and/or (2) TVA did not attempt to negotiate better prices at BFN.

Vertical Crawler

Contract No. 99999906 provided that the pricing for (b) (4) [redacted] (b) (4) [redacted] Although the price TVA paid for the SQN crawler was in accordance with the cost-plus provision, the price for the BFN crawler was not. As discussed below, TVA's price for the BFN vertical crawler should have been at (b) (4) [redacted] ess than the amount quoted by Holtec. Additionally, since Holtec's price quote for BFN was (b) (4) [redacted] in our opinion the quoted price was a misrepresentation by Holtec that it was complying with the contract's pricing provision.

Holtec's Cost for Vertical Crawler Supplied to BFN – The vertical crawlers provided for SQN and BFN were manufactured and sold to Holtec by Lift Systems. Although the SQN crawler

Charles A. Kandt
Page 4
July 30, 2007

had been ordered by Holtec specifically for the SQN project, the crawler that was sent to BFN had originally been ordered by Holtec for a project it had with Hope Creek Nuclear Plant (Hope Creek). When TVA requested Holtec to provide a crawler for BFN, to meet TVA's time requirements Holtec apparently requested Lift Systems to (1) send the crawler that had been manufactured for Hope Creek to BFN and (2) manufacture another crawler for Hope Creek.

We reviewed documentation of the prices Holtec paid Lift Systems for each of the crawlers and found Holtec had paid Lift Systems [redacted] (b) (4) [redacted] (b) (4) Based on the prices Holtec paid for the two vertical crawlers, the most that should have been billable to TVA would have been [redacted] (b) (4) [redacted][2]

Potential Misrepresentation by Holtec – [redacted] (b) (4) [redacted] (b) (4) [redacted] the quoted price misrepresented Holtec's compliance with the contract's cost-plus provision. Additionally, Holtec may have made false statements by informing TVA the price for the BFN crawler was higher than the price of the SQN crawler because the BFN crawler (1) had enhancements that the SQN crawler did not have and (2) included expediting fees. We found the enhancements on the BFN crawler were minor and would not have materially affected Holtec's cost. Additionally, we found no evidence that Holtec incurred any expediting fees other than the higher price it paid Lift Systems for the replacement crawler for Hope Creek.

- - - - - -

Based on discussions we have had with [redacted] (b) (7)(C) [redacted] we understand OIG Investigations does not want Audit Operations to issue an audit report to TVA or Holtec at this time since the investigation is ongoing. Accordingly, we are providing the information in this memorandum for use in your ongoing investigation. If you need additional information, please contact [redacted] (b) (7)(C) [redacted] (b) (7)(C) [redacted]

Ben R. Wagner
Deputy Inspector General
ET 3C-K

JHB:JP
cc: Jack E. Brennan, ET 4C-K
[redacted] (b) (7)(C) [redacted]
Richard W. Moore, ET 4C-K
OIG File No. 2007-11160

[2] TVA could make an argument [redacted] (b) (4) [redacted] However, a legal opinion would be needed as to whether TVA could prevail at paying this lower cost since Holtec apparently had to pay a higher cost to replace the Hope Creek crawler.

EXHIBIT 26

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PHILIP D. MURPHY
Governor

Governor's Task Force on EDA Tax Incentives

Established Pursuant to Executive Order No. 52 (Murphy)

First Published Report

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Chairman

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Special Counsel

June 17, 2019

State of New Jersey

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I. EXECUTIVE SUMMARY

The Task Force on the Economic Development Authority's Tax Incentives (the "Task Force") is an advisory body and, pursuant to its mandate, submits this first report (the "First Report") to advise the Governor of its initial findings and recommendations.

In January 2018, Governor Philip D. Murphy directed the Office of the State Comptroller to conduct a comprehensive performance audit of the Grow New Jersey Assistance Act ("Grow NJ") and Economic Redevelopment and Growth ("ERG") tax-incentive programs (each a "Program" and together, the "Programs"), and predecessor programs, from 2010 forward, to "inform the public about the EDA's operations" and "assist lawmakers in their deliberations as to whether these programs should be reauthorized when they expire on July 1, 2019." On January 9, 2019, New Jersey State Comptroller Philip J. Degnan (the "Comptroller") issued his audit report[1] of the State's tax-incentive programs. The Comptroller's audit report revealed, among other things, that the New Jersey Economic Development Authority (the "EDA") had failed to comply with the applicable statutes and regulations and to implement key internal controls for monitoring the performance of tax-incentive beneficiaries.

In response to the Comptroller's audit report, Governor Murphy issued Executive Order No. 52, which established this Task Force with the following objectives:

1. Conduct an in-depth examination of the deficiencies in the design, implementation, and oversight of Grow NJ and the ERG tax-incentive programs, including those identified in the Comptroller's audit report, to inform consideration regarding the planning, development and execution of any future structure of these or similar tax-incentive programs; and

2. Hold public hearings and request testimony from individuals who can provide insight into the design, implementation, and oversight of these programs.

The Task Force has been authorized to call upon any department, office, division or agency of the State to supply it with data and any other information or assistance available to such agency as the Task Force deems necessary to execute its duties. Each State agency also has been required to timely cooperate with the Task Force. In addition, Governor Murphy appointed Professor Ronald Chen, as the Chairman of the Task Force, to "perform all of the functions of a duly authorized representative of the Governor" pursuant to N.J. Stat. § 52:15-7, including the ability to "subpoena

[1] A Performance Audit of Selected State Tax Incentive Programs, Jan. 9, 2019.

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and enforce the attendance of witnesses."[2] The Task Force has generally sought, in the first instance, to obtain information through witnesses' voluntary cooperation, but has also relied upon Professor Chen's subpoena power where necessary.

As described in more detail below, to fulfill its mandate, the Task Force has collected and reviewed thousands of documents—obtained from the EDA and other agencies, from companies awarded benefits under the Programs, and from other parties—and conducted 28 interviews to date. These interviews have included former and current EDA personnel and other government employees, as well as other parties with knowledge of or information about the design and administration of the Programs.[3] The Task Force has also interviewed several policy experts to provide insight on the structure and features of New Jersey's tax-incentive programs.

Although the Task Force's mandate encompasses both the Grow NJ and ERG programs, its investigation to date has focused primarily on Grow NJ. The Task Force's investigation is ongoing, and it intends to address ERG, as well as other aspects of Grow NJ, in later reports.

Given its mandate of examining the "design, implementation, and oversight" of the tax incentive programs, the Task Force began its analysis by dividing its efforts into two separate but related areas. In the first, it focused on the Programs' legislative underpinnings, examining factors relating to the design of the Programs, including whether special interests played a role in the statutory provisions. In the second, the Task Force focused on the EDA's implementation of the statutes and on its administration of the Programs. This included focus on examining the EDA's review and diligence over program applications to determine whether the EDA was employing meaningful scrutiny of those applications.

Although there is necessarily crossover among the issues encountered in these separate investigative areas, this investigative structure has enabled the Task Force to most efficiently and comprehensively examine the Programs. The description of our findings below follows this general investigative structure. The Task Force's findings are based upon the information available to the Task Force as of this date and are subject to further revision as the Task Force's investigation proceeds and additional information becomes available. In sum, the Task Force has found as follows:

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[2] *See* March 22, 2019 Letter from Governor Murphy to Professor Chen.
[3] We do not name EDA staff referenced herein, but we do name certain EDA senior managers.

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A. Special Interests, Which Prioritized Benefits to Private Parties Rather than the State, Had a Significant Impact on the Design of the Grow NJ Statutes and Regulations

With respect to the design of the statute, special interests—in the form of a law and lobbying firm and the clients on whose behalf it apparently operated—appear to have had a significant impact on the design of the Grow NJ statute as amended by the Economic Opportunity Act of 2013 (or "EOA 2013") and its implementing regulations. As a result of those special interests, EOA 2013 was—in several ways—structured to favor certain parties while disfavoring others in certain respects. For example, a statutory provision related to grocery stores in Camden appears to have been drafted to permit a particular grocery store to obtain tax incentives, while prohibiting a competitor grocery store from obtaining such benefits. Although neither grocery store ultimately opened in Camden, the drafts of this provision highlight the significant and, in the Task Force's view, inappropriate role special interests played in crafting the statute.

In addition, the Grow NJ program was dramatically expanded by EOA 2013 in numerous respects. Principal among these amendments were provisions that allowed projects in Camden—where many of the law firm's clients had business interests—to receive awards far in excess of what would have been possible in other parts of the State. Unlike the requirements applicable in other parts of the State that Grow NJ awards be anticipated to result in a net positive benefit to the State in terms of new tax revenue, these large awards for projects in Camden could be based on "phantom" taxes that would never actually accrue and thus might not result in a gain to the public fisc.

B. The EDA Did Not Have Adequate Procedures in Place to Ensure That It Discovered Relevant Information, Including Applicant Misstatements, That Would Have Led to Rejection of Some Applications or a Significant Reduction in the Amount of Certain Awards

With respect to the administration of the Programs, the EDA had only a few formal written policies and procedures to provide guidance to the EDA employees tasked with reviewing companies' applications for tax incentives. Even more troubling, the EDA lacked any formal training to ensure those same employees had a common understanding of Program requirements or clear rules for conducting due diligence on tax-incentive applications, which often involved awards of millions of dollars. This fundamental lack of controls led to important misunderstandings over threshold requirements for applications and inconsistency within the EDA in its evaluation and application of Program requirements—including confusion over even the basic level of scrutiny to be applied to applications, with some EDA employees viewing the vetting process as a "box

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checking" exercise, during which a company's factual assertions deserved deference, and other employees applying meaningful scrutiny.

Relatedly, the EDA did not have any protocol or written standards for conducting research in connection with companies' applications for Program benefits. As a result, at least with respect to the applications the Task Force has investigated in detail thus far, some EDA employees conducted independent research to verify aspects of applicants' factual assertions and others failed to do so, even when relevant information was readily available. For example:

- A simple internet search revealed that one company, Holtec International, had been debarred by the Tennessee Valley Authority, even though Holtec said it had never been debarred in its Grow NJ application. Although such a debarment would have been grounds for the EDA to deny Holtec's application for tax incentives, the Task Force found no evidence that the EDA discovered Holtec's debarment. Apparently unaware of the debarment, the EDA ultimately approved Holtec for a $260 million Grow NJ award.

- Another simple internet search revealed that three companies—Conner Strong & Buckelew Companies, LLC, The Michaels Organization, LLC, and NFI, L.P.—committed to move to Camden more than a year before submitting their applications for tax incentives, in which they claimed they were considering relocating to Pennsylvania as a potential alternative. Had the EDA's employees found this information,[4] the EDA may have found these applications materially misleading, and denied an award on that basis. At a minimum, armed with this information, the EDA should have calculated these awards based only on new jobs moving to Camden from outside the State, and the awards to these three entities combined would have been reduced by over $70 million.

[4] As we discuss below in Section V(C)(4)(b)(i) of this First Report, we found evidence that the then-President and Chief Operating Officer of the EDA, Tim Lizura, should have reasonably known by September 24, 2015—thirteen months before these three companies applied for tax incentives under the Grow NJ program—that these applicants had committed to the Camden project. This meant that their certifications in their applications that jobs were "at risk" of leaving New Jersey were, at best, dubious. We found no evidence that Mr. Lizura shared this information with either the Business Development Officer or Underwriter responsible for these applications. We continue to investigate this issue.

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To date, our investigation has uncovered no evidence that the EDA intentionally ignored this information, but the failure to have strict guidelines for such research made these lapses possible. Indeed, in another instance, the EDA failed to follow up on red flags (that is, concerns or cause to follow-up) in the actual application materials submitted by the applicant itself. The Cooper Health System acknowledged in its initial application materials that no jobs were at risk of leaving New Jersey and it was not considering any out-of-state locations. The EDA subsequently accepted, without any skepticism or further diligence, Cooper Health's later claim that it was considering an out-of-state relocation, and approved Cooper Health for nearly $40 million in tax incentives. The evidence shows otherwise. Had the EDA calculated Cooper Health's award based on its initial representation that no jobs were at risk of leaving the State, Cooper Health's award would have been approximately $7 million—more than $32 million lower than what it was awarded.

Although the Task Force's investigation is ongoing, below we make a number of recommendations for future legislation, as well as for the EDA's procedures in administering the Programs, based on its findings to date. By way of summary, those include:

- Designing any future legislation to ensure as much as possible that the public policy goals are applied neutrally, without favoring specific business interests;
- Assuring that persons or firms who represent tax-incentive applicants are properly registered as lobbyists under the New Jersey Legislative and Governmental Process Activities Disclosure Act;[5]
- Refraining from providing draft EDA regulations to people or firms that represent tax-incentive applicants outside the public notice-and-comment procedure under the New Jersey Administrative Procedure Act;[6]
- Taking steps to ensure that tax incentives are structured so that they result in a net gain to the State, or, if they do not, that fact is transparent;
- Ensuring that the language of any new legislation and implementing regulations more clearly sets forth the standards to be applied in determining eligibility for tax incentives;
- Strengthening the EDA's ability to withhold all or part of an award where a company has failed to meet its commitments, and ensuring that the EDA has sufficient data to fully evaluate a company's compliance with its incentive agreement;

[5] N.J. Stat. § 52:13C-18 et seq.
[6] N.J. Stat. § 52:14B-1 et seq.

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- Requiring the EDA to implement formal written policies and procedures governing all aspects of the Programs and their administration and to undertake to formally train its staff in how to review Program applications and monitor compliance;
- Requiring the EDA to use an experienced professional services firm to conduct a background check on each applicant and its affiliates and senior executives; and
- Strengthening the EDA's process for conducting diligence into an applicant's claim that it intends to locate out of state absent the award of tax incentives from New Jersey.

In addition to examining the design and administration of the Programs, the Task Force has established an accelerated recertification program, or "ARP," pursuant to which companies can voluntarily submit information to establish that they have been and remain in compliance with all Program requirements. We did this for two reasons: (1) we desired to streamline our work to focus on the most serious issues; and (2) if the EDA did an inadequate job vetting applications, but the applicant had business records to demonstrate its compliance with Program requirements, the EDA's oversight lapses for these applications would not have had a negative impact on the public fisc. Currently, 53 companies have pursued participation in the ARP.[7]

Finally, although our focus has been and shall remain on the EDA, our investigation necessarily involves a review of companies' tax-incentive applications to determine how the EDA administered the Grow NJ and ERG programs. As a corollary to our work, the Task Force has uncovered several instances where Program beneficiaries have—whether intentionally or not—failed to comply with Program requirements, either by submitting inaccurate information in their applications or by subsequently falling out of compliance. The Task Force has obtained some voluntary terminations of awards, and has referred others to the State Treasury or either law enforcement agencies, the EDA, or both, which may result in, among other things, steps to suspend or terminate these awards. The aggregate value of the awards that were either voluntarily terminated or may be subject to such suspension/termination actions exceeds $500 million.

II. INTRODUCTION TO THE PROGRAMS

New Jersey currently has two principal tax-incentive programs: Grow NJ and ERG. A brief summary of both programs follows.

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[7] Of these companies, the Task Force has identified several companies that present threshold issues, which must be resolved before the company can proceed with the ARP. The Task Force is working with these companies to obtain additional information before it makes a final decision regarding their participation in the ARP.

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Grow NJ is generally intended to incentivize the creation of new jobs in the State or the retention of existing jobs that, absent the provision of tax incentives, would be eliminated or relocated outside New Jersey. To qualify for tax incentives under Grow NJ, a company must agree to make a minimum capital investment in a business facility—for example, the company may construct a new office building or rent new office space—at which the company agrees to create a minimum number of new jobs or retain a minimum number of existing jobs that, absent the tax incentives, would be eliminated or relocated out of state.[8] The Grow NJ program is intended to incentivize a company's capital investment and job creation or retention, together often referred to as a "project" by the company To qualify for the tax incentives, the company is usually required to demonstrate that, unless the incentives are provided (in the language of the statute, "but for" the incentives), the company's jobs would be eliminated or located outside New Jersey.[9]

ERG is generally intended to incentivize commercial and residential real estate development in qualifying locations in the State. To qualify for tax incentives under ERG, applicants are required to demonstrate a project financing gap—the costs that remain to be financed after accounting for all other sources of capital. [10]

The Task Force's investigation to date has focused on the Grow NJ program.

III. INVESTIGATIVE PROCESS

In this initial phase of its investigation, the Task Force sought to go beyond the scope of the Comptroller's audit as required by Executive Order No. 52. To that end, the Task Force sought to examine the design of the Programs and, further, to identify and investigate internal-control deficiencies in the EDA's administration and implementation of the Programs. To accomplish these aims, the Task Force established an investigative process for two separate, but related, work streams:

A. First Work Stream: The Design of the Tax-Incentive Programs

To carry out its examination of the design of the Programs, the Task Force needed to examine the history of the statutes relevant to the Programs. These statutes included:

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[8] *See* N.J. Stat. § 34:1B-244(a).
[9] *See* N.J. Stat. § 34:1B-244(d). The statute has different provisions that apply to projects in Camden and Atlantic City, which replace the "but for" test that is applicable in other parts of the State with an alternative "material factor" test. These provisions are discussed below.
[10] *See* N.J. Stat. §§ 52:27D-489e, 52:27D-489c ("project financing gap" definition).

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- The New Jersey Economic Development Authority Act, which in 1974 created the EDA as a state governmental agency and defined its authority.[11]
- The New Jersey Economic Stimulus Act of 2009 (the "ERG Act"), which created the ERG program in 2009, to be administered by the EDA.[12]
- The Grow New Jersey Assistance Act (the "Grow NJ Act"), which created the Grow NJ program in 2012, also to be administered by the EDA.[13]
- The New Jersey Economic Opportunity Act of 2013 ("EOA 2013"), which significantly revamped and expanded both the Grow NJ and ERG programs in 2013.[14]
- Multiple subsequent statutory amendments that revised the Grow NJ and ERG programs in relatively more minor ways between 2013 and the present.

Since the Governor's investigatory power is limited to the Executive Branch,[15] the Task Force did not affirmatively investigate the Legislature itself or its passage of these statutes, beyond what is available in the public domain. However, the statutes collectively create and define the Programs and, in addition, set out the parameters of the EDA's lawful discretion in its administration of them. As such, it is both within the Task Force's mandate—and necessary to the Task Force's mission—to analyze all pertinent aspects of the controlling statutory design, as embodied in the relevant statutes.

The Task Force began its analysis of the statutory design and history with publicly available documents, including the current versions of the statutes themselves and proposed and enacted bills and legislative statements.[16] The Task Force also reviewed and analyzed certain non-public evidence bearing upon the statutory design. During the investigation, the Task Force obtained draft

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[11] P.L. 1974, c. 80 (current version codified at N.J. Stat. § 34:1B-1 et seq.).
[12] P.L. 2009, c. 90 (current version codified at N.J. Stat. § 52:27D-489e et seq.).
[13] P.L. 2011, c. 149 (current version codified at N.J. Stat. § 34:1B-242 et seq.).
[14] P.L. 2013, c. 161.
[15] N.J. Const., art. V, § 4, ¶ 5 ("The Governor may cause an investigation to be made of the conduct in office of any officer or employee who receives his compensation from the State of New Jersey, except a member, officer or employee of the Legislature or an officer elected by the Senate and General Assembly in joint meeting, or a judicial officer.").
[16] These draft versions of the bill are attached as Exhibits 1 and 2. The current statutes, as well as proposed and enacted bills legislative statements, are available on the Legislature's website. *See* N.J. Legislature, https://www.njleg.state.nj.us.

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versions of the EOA 2013 bill dated June 21, 2013.[17] The draft reflected revisions made in "track changes" mode and included metadata showing the author of each respective revision. The Task Force also acquired and analyzed a substantial number of documents from governmental sources, including the EDA. In many cases, these documents provided further evidence concerning relevant context surrounding the statutory design and the parties who impacted it.[18] The Task Force also spoke to witnesses who provided context concerning the special interests that affected the statutory design in various respects.

Through review and analysis of these public and non-public materials, the Task Force acquired significant information concerning the design of the Programs and the limitations on the EDA's discretion in its administration of them. The Task Force received evidence demonstrating that the EDA opposed some of these statutory provisions and in certain instances advocated for alternative provisions. However, because they were enacted into law, the EDA was required to faithfully administer them, irrespective of whether they were justifiable as sound policy.

The Task Force also analyzed the design and history of the EDA's implementing regulations for the Programs. Like other governmental agencies tasked with the administration of government programs, the EDA is authorized by New Jersey law to promulgate regulations that interpret the statutes implemented by the agency, including the Grow NJ and ERG Acts. While agency regulations must be faithful to the laws they implement, they may provide additional rules beyond those expressly set out by the statutes—in this way, agency regulations serve to effectively "fill in the gaps" in the statutes. The New Jersey Administrative Procedure Act (the "APA") sets out certain procedures that New Jersey agencies, including the EDA, must follow when promulgating regulations.[19] The APA requires a so-called "notice-and-comment" process in which agencies, before issuing final regulations with the force of law, must first provide the public with notice of the regulations they are considering and receive and consider comments from interested members

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[17] One of these draft versions was in the EDA's files. In addition, the Task Force learned that a law firm likely had additional versions of the draft legislation. Although this firm initially promised full cooperation with the Task Force, it subsequently declined to produce these versions without a subpoena.

[18] This investigation revealed that certain persons appeared to have engaged in unregistered lobbying in New Jersey, in apparent violation of the New Jersey Legislative and Governmental Process Activities Disclosure Act, N.J. Stat. § 52:13C-18 et seq. The Task Force referred this matter to appropriate law enforcement authorities, as previously disclosed.

[19] *See* N.J. Stat. § 52:14B-1 et seq.

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of the public. The Task Force has investigated the EDA's processes in this respect, primarily through analysis of documents and information provided by the EDA.

B. Second Work Stream: EDA's Administration of the Tax-Incentive Programs

To carry out its examination of the EDA's administration and implementation of the Programs, the Task Force established an Investigative Process to methodically identify, collect, review, and analyze pertinent information and data. The Task Force began by conducting a linear investigation of the Grow NJ and ERG application processes, from pre-application discussions through approval to annual certification and credit of the tax incentive awards. We examined these processes both by looking at the EDA's internal processes and files and by gathering information about, and from, the companies that were awarded incentives under the Programs.[20] At the onset of our investigation, we met with Friedman Kaplan Seiler and Adelman LLP ("Friedman Kaplan"), counsel for the EDA to get an overview of the EDA's processes and procedures. We then deepened our understanding of the processes and applicants—and various issues with them—through interviews of relevant personnel (both from within the EDA and outside the EDA) and review of relevant documents. As discussed below, the initial scope naturally expanded as the Task Force acquired, reviewed, and analyzed relevant evidence bearing on the EDA's processes and individual companies.

1. Background Meetings

The Task Force requested to meet with the EDA, State Treasury, and the State Comptroller's Office immediately after its inception to better understand the interplay of various State agencies involved in the process. At the initial meeting referenced above, Friedman Kaplan provided a high-level overview of the application process from pre-application through certification of a tax-incentive grant. Friedman Kaplan has continued to work cooperatively with the Task Force to produce documents and information and to review and assess the internal processes and controls within the EDA as they relate to the tax-incentive programs.

The Task Force also met with members of the Treasury Department's Division of Taxation (the "Treasury"). The Treasury provided an overview of its role in the administration and implementation of the Programs. Beyond a general overview, Treasury explained the

[20] Although we have begun our investigation of the certification and credit-award processes, our investigation thus far has largely been focused on the earlier stages of the approval process.

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documentation, memoranda, and certifications it reviews and approves before awarding a tax credit to a Program applicant.

The Task Force interviewed State Comptroller Philip Degnan and members of his audit team with the goal of obtaining a better understanding of the Comptroller's findings regarding the EDA's processes and procedures. Comptroller Degnan and his team provided an overview of their audit and findings and have continued to work collaboratively with the Task Force to provide information and offer consultation with respect to the Comptroller's audit.

The Task Force requested ongoing cooperation with the EDA and the State Comptroller's Office and for both entities to ensure that they were preserving relevant documents. The EDA, Treasury, and Comptroller's office have provided the Task Force with numerous documents in response to our requests. The bulk of the documents the Task Force has obtained have come from the EDA. Thus far, the Task Force has obtained over 1,069,789 pages of materials from the EDA and is continuing to conduct a strategic review of these materials.

2. Definition of Scope and Document Preservation and Collection

The Task Force worked collaboratively with the EDA to compile a list of all companies that have been certified to receive a Program award and did in fact receive a tax credit. Based on these parameters, there were 106 projects in the Task Force's initial scope. The Task Force subsequently expanded the scope of its investigation to include certain additional companies that had been approved for a tax-incentive award but that had not yet received tax credits. Those companies are discussed in more detail below.

a) Document Preservation and Company Outreach

The Task Force sent document preservation directive letters to companies that were identified as within its initial scope. The preservation notice informed the companies that the Task Force may seek information and documents relevant to the Programs and that the companies should take affirmative steps to ensure that all relevant documents would be preserved. To date, the Task Force has sent preservation letters to 116 companies.[21] In addition, the Task Force sent preservation notices to additional entities identified as related to Program applications and legislative design. In order to understand the EDA's review process for Program applications, the Task Force sought to identify what business records and documents existed, which would bear on company applications and certifications, even if the EDA chose not to request such documentation. The EDA has broad

[21] This includes companies that did not fall within the Task Force's initial scope but were later added to the investigative work stream based on leads obtained during the investigation.

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authority to request additional information from applicants,[22] but did not use this express authority in every case.

The Task Force reached out to each company to confirm (a) that the company had received the preservation directive; and (b) that the company was taking requisite steps to comply with the directive. The Task Force made contact with a majority of the companies. However, there is still a small number of companies that have not been reached due to inaccurate contact information, dissolution of the company, or failure of the company to respond.

b) Refinement of Scope

In order to methodically review the EDA's oversight of Program applications, as discussed below in detail, the Task Force created an "accelerated recertification program" ("ARP"). In the ARP, the Task Force is providing companies an opportunity to demonstrate that they (a) are in compliance with the Programs and (b) applied for tax incentives in good faith. For companies that successfully recertify through the ARP, the Task Force has agreed not to request further documents or information.

The Task Force segregated processes for companies enrolled in the ARP from the remaining companies (the "Non-ARP Group"). As of the date of this report, there are 63 companies in the Non-ARP Group. For these companies, the Task Force is conducting a thorough investigation of the EDA's oversight of these applicants. We also interviewed a number of witnesses, who provided information concerning relevant misconduct by individuals associated with Program applicants.

The Task Force initially focused on Program applications where a "red flag" had been raised through our initial document review and interviews. In this regard, a draft of EOA 2013 edited by Parker McCay, a law and lobbying firm that represented several clients whose interests, as discussed below, were impacted by EOA 2013 played an important role in our focus. Because those drafts were edited by a private law and lobbying firm, which seemed to be adding special provisions to the bill to benefit particular clients, the Task Force viewed this as a serious "red flag" for those clients who certified that their jobs were "at risk" of leaving the State. The Task Force was skeptical that a client, on the one hand, would consult with their lawyer about—what amounted to—special legislation for their benefit but, on the other hand, was seriously considering a move

[22] *See* N.J. Admin. Code §§ 19:31-18:5 (Grow NJ) and 19:31-4.4 (ERG) (setting forth application submission requirements and providing that the EDA may request "any other necessary and relevant information as determined by the [EDA] for a specific application").

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out of the State knowing it could receive very significant awards through the inclusion of those provisions.

c) Company and Third-Party Production of Documents

The Task Force has also obtained relevant documents from companies in the Non-ARP Group, from consultants and lawyers retained by companies in connection with their Program applications, and from additional parties with relevant information. The Task Force sought voluntary cooperation from all companies, individuals, and related entities, but when necessary, the Task Force recommended that Professor Chen issue subpoenas to obtain relevant documents.

3. Witness Interviews

In addition to the initial interviews described above, the Task Force has conducted numerous interviews of individuals relevant to is mandate. The Task Force has interviewed 12 current EDA employees. The employees interested were involved in the application pre-approval process at the officer, manager, and director levels as well as individuals in Human Resources, Operations and tax credit transfer positions. The Task Force has interviewed 2 former EDA employees who held senior leadership positions, Tim Lizura, the former President and Chief Operating Officer, and Maureen Hassett,[23] a former Senior Vice President of Finance and Development.

The Task Force also reached out to non-EDA individuals and potential witnesses identified as having information relevant to the Programs or to award recipients. Thus far, the Task Force has interviewed 14 non-EDA witnesses.

IV. LEGISLATIVE FOCUS: THE DESIGN AND IMPLEMENTATION OF THE TAX-INCENTIVE PROGRAMS

A. Initial Findings

As further discussed below, the draft versions of the EOA 2013 bill dated June 21, 2013, reviewed in conjunction with publicly available versions of the bill and other documents and information in the Task Force's possession, indicated that certain special interests played a key role in numerous provisions that were ultimately enacted into New Jersey law, and which, when administered by the EDA, would provide significant benefits to those special interests. Certain aspects of the Grow NJ program's design are difficult to justify from a rational policy perspective and can be understood only as the result of a process in which certain favored private parties were

[23] Ms. Hassett is currently working with the Treasury Department, but is still employed by the EDA.

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permitted to shape the legislation to their benefit—and further, in some cases, to disfavor potential competitors.

The Task Force has found that the same special interests who successfully impacted the legislative design of the Programs were also afforded privileged status with respect to the Programs' implementing regulations. The EDA provided these special interests with early information about the regulations the agency was considering, prior to the notice provided to other members of the public, and permitted them to provide private feedback—which, in some instances, the EDA accepted and incorporated into the regulations. Moreover, the influence exerted by these special interests over this process was not disclosed to the public.

Thus, the Task Force's investigation to date has found that special interests succeeded in molding both the Programs' legislation and implementing regulations in their favor. The result is that New Jersey's tax-incentive programs have not been "neutral" in their design but have rather been structured in respects both large and small to favor the business interests of favored parties, sometimes in ways of debatable merit from a public policy standpoint. This is troubling for many reasons, including that the New Jersey Constitution contains certain prohibitions on "special legislation."[24] These constitutional prohibitions, the New Jersey Supreme Court has explained, were intended to combat "the propensities of legislatures to indulge in favoritism."[25] Given the findings discussed below, there may be reasonable questions as to whether New Jersey's current tax-incentive laws are compatible with constitutional requirements.

Some will certainly note that the problematic examples described below center on projects located in the City of Camden. The Task Force should not be misunderstood as disagreeing in any way about the desirability—indeed the necessity—of the State finding ways to encourage substantial reinvestment and growth in Camden, and in helping it meet the substantial challenges that it faces. Reinvestment in Camden has rightly been a priority for governors from both major political parties for decades. But as laudable as that *end* is, it does not necessarily justify, without any question or limitation, every conceivable *means* to accomplish it. "Shoehorning" the priority of *capital investment* in Camden in the Grow NJ program, the priority of which is the equally desirable but very different goal of *job growth*, has led to confusion in eligibility criteria, mismatched metrics of accountability, and lack of enforcement of the program requirements by the very agency that is responsible for monitoring it. Allocation of scarce public resources must inevitably involve some inquiry into the relationship, and resulting efficiency, between ends and

[24] N.J. Const., art. IV, § VII, ¶¶ 7-9.
[25] *Vreeland v. Byrne*, 72 N.J. 292, 298 (1977).

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means, and the absence of that logical nexus has been painfully evident in the course of the Task Force's work.

1. Influence by Special Interests in Grow NJ's Legislative Design

The Grow NJ program was created in 2012 by the Grow NJ Act.[26] Compared to the version of Grow NJ that exists today, the original iteration of the program was relatively modest. Individually, the maximum awards available to program beneficiaries were far smaller than the maximum awards now possible under the current version of Grow NJ. Collectively, the original Grow NJ program provided a programmatic cap of up to $200 million in tax credits that the EDA could approve.[27] The current version of Grow NJ, by contrast, has no such programmatic cap, which has allowed tax incentive approvals to balloon to the point that billions are now outstanding. Indeed, under the current version of Grow NJ, multiple companies have been individually approved for awards in excess of $200 million in tax incentives, meaning that each of these companies by itself exceeded the maximum programmatic cap under the original iteration of the Grow NJ program.

The original version of Grow NJ existed for less than two years before it was significantly revamped and expanded by EOA 2013. The initial EOA 2013 bill was introduced in the New Jersey General Assembly on January 14, 2013 as Assembly Bill Number 3680. The Assembly passed the bill on May 20, 2013, and sent it to the Senate.

The Task Force has received evidence and information demonstrating that, during this period when EOA 2013 was before the Senate, certain special interests became involved in the drafting process—namely, the Parker McCay P.A. law and lobbying firm based in Mount Laurel, Hamilton, and Atlantic City, which drafted large swaths of the bill in various respects that appear to have been intended to benefit the firm's clients. Based on evidence and information in possession of the Task Force, Philip A. Norcross, Parker McCay's Managing Shareholder and Chief Executive Officer, and Kevin D. Sheehan, another partner of the firm, both worked on the drafting of the bill. Among other apparent intended beneficiaries of Parker McCay's drafting work was the Conner Strong & Buckelew insurance brokerage firm, headed by its Executive Chairman, George E. Norcross, III—the brother of Philip A. Norcross. Several years after EOA 2013 was enacted, on March 24, 2017, Conner Strong & Buckelew was approved for an $86 million award to relocate its

[26] P.L. 2011, c. 149.
[27] The EDA was also statutorily permitted to raise the programmatic cap if it would determine that doing so was "reasonable, justifiable, and appropriate."

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offices to Camden. An award of that size would have likely been impossible if not for statutory amendments that Parker McCay played a pivotal role in incorporating into the legislative design.

The Task Force has received two Microsoft Word draft versions of the bill, both dated June 21, 2013—one draft dated several hours earlier than the other one—with revisions in "track changes" mode. The metadata in these documents appear to attribute many, but not all, of the revisions in the bill to Mr. Sheehan of Parker McCay.[28] In addition to this metadata, other documents and information in the Task Force's possession further corroborate that Mr. Sheehan, with the potential influence of Mr. Norcross, drafted these changes to the bill.

On June 24, 2013, the Senate Budget and Appropriations Committee favorably reported its amended version of the bill, which incorporated many of the bill revisions that were drafted in whole or in part by Parker McCay and reflected in the June 21, 2013 working drafts. As a result of these changes, the bill dramatically expanded in both length—the version of the bill favorably reported by the Senate committee was double the length of the bill that had been passed by the Assembly—and substantive scope. Numerous provisions were added to the bill expanding the availability of tax incentives under the Grow NJ program.

On June 27, 2013, the Senate passed its version of the EOA 2013 bill, incorporating many of Mr. Sheehan's revisions, and returned the bill to the Assembly. That same day, the Assembly concurred in the amended bill, with additional amendments, and returned it to the Senate. The Senate passed the amended bill on August 19, 2013, sending it to the Governor. Governor Chris Christie conditionally vetoed the bill on September 9, 2013, recommending limited revisions. The Assembly and the Senate both concurred in Governor Christie's recommended revisions and returned the bill to him. The EOA 2013 was finally enacted into law on September 18, 2013. The provisions of the bill drafted in whole or in part by Parker McCay largely survived this iterative process and were included in the final bill enacted into law.

Several of the most important or otherwise notable aspects of Grow NJ's amendments under the EOA 2013 are discussed below. These amendments, each of which Parker McCay appears to have had some role in drafting, are illustrative of some of the ways Grow NJ's statutory design following the enactment of the EOA 2013 was structured to favor chosen special interests in ways both large and small, sometimes arguably to the detriment of the public interest. It is important to

[28] These draft versions of the bill are attached as Exhibits 1 and 2. The authorship information in the metadata is not visible in these exhibits.

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note that the EOA 2013's changes to the Grow NJ program were innumerable and complex, and most will not be discussed in this First Report.

a) Tax Incentives for Grocery Stores in Camden

Grow NJ, both in its original and current iterations, has generally precluded tax incentives for retail businesses.[29] The EOA 2013 included several provisions, however, drafted in part by Parker McCay, which expressly authorized the EDA, as an exception from the otherwise applicable exclusion for retail projects, to award tax incentives to companies that would build grocery stores in Camden. The policy basis to incentivize development of grocery stores in Camden is readily apparent, because Camden has for decades been described as a "food desert" in which there are insufficient grocery stores to serve the city's residents.[30]

However, notwithstanding the indisputable need to increase food access in Camden, the EOA 2013 did not allow tax incentives for all or even most potential grocery stores that could be built in the city. Instead, the EOA 2013 amended the Grow NJ statute to allow tax incentives for a "full-service supermarket or grocery store" *only* if it would be "at least 50 percent" of a larger retail development "of at least 150,000 square feet."[31] Therefore, the grocery store itself must be at least 75,000 square feet at a minimum to qualify for tax incentives. For reference, the average American grocery store size around this time was reported to be approximately 46,000 square feet—far below the minimum threshold size required to qualify for tax incentives under Grow NJ as amended by the EOA 2013.[32] If the goal was to alleviate the lack of local food access for Camden residents, an ostensible policy justification for limiting the incentives to supersized grocery stores, while

[29] *See* N.J. Stat. § 34:1B-243 (generally excluding "business[es] that [are] . . . engaged in final point of sale retail" from the definition of the "qualified business facilit[ies]" that are eligible for tax incentives).
[30] *See* Hr'g Tr. (May 2, 2019) at 202:24-203:6 (testimony that Camden was considered a food desert in which the city's residents lacked convenient access to a grocery store).
[31] *See* N.J. Stat. § 34:1B-243 ("qualified business facility" definition).
[32] *See* Brad Tuttle, *Your Grocery Store May Soon Be Cut in Half*, MONEY, June 2, 2014, http://money.com/money/136330/why-your-grocery-store-may-soon-be-cut-in-half; Brad Tuttle, *Fewer Choices, More Savings: The New Way to Buy Groceries*, TIME, Jan. 25, 2011, http://business.time.com/2011/01/25/fewer-choices-more-savings-the-new-way-to-buy-groceries.

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excluding such incentives for grocery stores of average or even large sizes that would also provide Camden residents with increased food access, is not obvious.[33]

The Task Force's investigation to date has found that the cause of this statutory limitation appears to have not likely been considerations of the public interest, but rather the private business interests of one of Parker McCay's clients. In March of 2013, before the EOA 2013 was enacted, the owners of several grocery stores in New Jersey and a development firm announced that they had partnered in a joint venture to open a ShopRite grocery store in Camden, which would anchor a larger retail shopping center.[34] Mr. Sheehan and Mr. Norcross of Parker McCay represented the retail project, which, when completed, was planned to be over 150,000 square feet, with at least 50 percent occupied by the grocery store. Meanwhile, around this same time, another developer had separate plans to build a different retail development in Camden that would also be anchored by a grocery store. This competitor retail development was planned to be smaller, such that it would not qualify for tax-incentive subsidies under the EOA 2013 amendment, while the retail development that Parker McCay represented would.

It should be noted that both projects ultimately failed, and neither grocery store was built. The Task Force has received evidence demonstrating that the project Parker McCay represented initiated efforts to receive tax incentives from the EDA, but the project collapsed before any award was approved.[35] The competitor project, which was necessarily disqualified for tax incentives as a result of this EOA 2013 amendment, also failed.

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[33] EDA's former President and Chief Operating Officer Tim Lizura testified at the Task Force's May 2, 2019 public hearing that "[y]ou can make an argument" for tax incentives for grocery stores of any size in Camden, but with respect to this limitation, "it didn't offend us that that was the provision that was there." Hr'g Tr. (May 2, 2019) at 236:16-238:9.

[34] *See Mayor Redd, The Goldenberg Group, and Ravitz Family ShopRites Announce Major Retail Project in Camden*, CITY OF CAMDEN, March 19, 2013, https://www.ci.camden.nj.us/releases/mayor-redd-the-goldenberg-group-and-ravitz-family-shoprites-announce-major-retail-project-in-camden.

[35] *See* Allison Steele, *Long-promised Camden supermarket isn't coming*, PHILA. INQUIRER, Aug. 9, 2016, https://www.inquirer.com/philly/news/new_jersey/20160810_Long-promised_Camden_supermarket_isn_ t_coming.html ("Plans to build a ShopRite supermarket on the Admiral Wilson Boulevard in Camden, a project that officials had said would create permanent jobs and provide improved access to fresh, affordable food, have fallen apart, according to sources with knowledge of the situation. Instead, Actega North America Inc., a Delran-based company that makes coatings and sealants, on Tuesday was approved to receive $40 million in state tax incentives if it decides to

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b) The Alternative Approach to Award Calculation for Incentivized Camden Projects

As a general rule, the Grow NJ Act provides that the size of a tax incentive award is determined by a relatively straightforward formula that is tied to the number of new jobs created by the company in New Jersey and/or the number of existing jobs retained by the company in New Jersey that, absent the tax incentive award, would be relocated out of state or eliminated.[36] First, a "base" amount per job—ranging from between $500 to $5,000 annually—is determined based on certain statutorily defined factors (primarily the location of the project).[37] Second, any applicable statutorily defined "bonus" amounts are applied to increase the total award per job.[38] For example, jobs in a "targeted industry" (the EDA is statutorily authorized to determine which industries are "targeted") are eligible to receive an increase of $500 annually per job.[39] Under this statutory formula, the maximum possible award per job is $15,000 annually.[40]

However, provisions of the EOA 2013, drafted in part by Parker McCay, amended the Grow NJ statute to set out an additional, alternative approach to award calculation exclusively for incentivized projects located in Camden. Under these provisions, the award calculation for Camden projects is effectively decoupled from the number of jobs created or retained by the company, and is instead tied to—and, unless capped by an applicable statutory limitation, equal to—the size of the company's capital investment in the project.[41] These provisions have allowed companies that agreed to make large capital investments in projects located in Camden to qualify for awards far exceeding the amounts that would have otherwise been permitted.

For an illustration of the difference between the statutory formula approach under Grow NJ for award calculation and what is often referred to as the "Camden alternative" approach, consider a hypothetical project in which a company will invest $100 million to build a new office building in New Jersey at which the company plans to hire 250 new employees. Under the formula approach applicable to projects in most of the State, with a maximum annual per-job award of $15,000, as

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build a 130,000-square foot headquarters on the site. . . . No explanation has been provided for why the ShopRite project collapsed.").

[36] *See* N.J. Stat. § 34:1B-246(a)–(d).

[37] *See* N.J. Stat. § 34:1B-246(b).

[38] *See* N.J. Stat. § 34:1B-246(c).

[39] *See* N.J. Stat. §§ 34:1B-246(c), 34:1B-243 ("targeted industry" definition).

[40] *See* N.J. Stat. § 34:1B-246(d).

[41] *See* N.J. Stat. § 34:1B-246(d) (subsection beginning, "Notwithstanding anything to the contrary set forth herein and in the provisions of subsections a. through f. of this section . . .").

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discussed above, the largest possible award for the company would be $3.75 million each year ($15,000 x 250 jobs). Over the ten-year term for awards under Grow NJ, the maximum award would be $37.5 million ($3.75 million x 10 years). If the project were in Camden, however, and subject to the Camden alternative approach to award calculation, the company could receive an award of $100 million, equal to the size of the anticipated costs to build the new office building—over twice the size of the maximum award available in other parts of the State.

Numerous Parker McCay clients have benefited from the Camden alternative approach to award calculation. As noted previously, Parker McCay client, the Conner Strong & Buckelew insurance brokerage firm, was approved by the EDA on March 24, 2017 for an $86 million award to relocate 268 jobs from the company's existing offices to a new office tower to be built on the Camden waterfront. Pursuant to the Camden alternative provisions of EOA 2013, this award was based on the claimed anticipated costs of the office tower's construction. Under the formula approach to award calculation, the company could have potentially, in the best possible circumstances for it, qualified for a maximum award of $40.2 million ($15,000 x 268 jobs x 10 years).

The Task Force has not conducted an economic analysis of the approaches to award calculations under Grow NJ and therefore has made no finding concerning whether the increased size of Camden alternative awards is sensible as a matter of public policy. Indeed, given the enormous challenges facing Camden, one of New Jersey's poorest cities, an up-front decision by the State to appropriate substantial resources—through the normal procedures for allocating State resources—to invest in the capital infrastructure would have been completely understandable.

However, while there are certainly rational policy justifications for providing incentives for capital projects located in Camden, the Camden alternative approach in the EOA 2013, which do so in the context of an enhanced tax-incentive program ostensibly dedicated to job growth, has been criticized as excessive by a number of parties given the potentially large cost to the State, and even many of its defenders have said that it may need to be appropriately reconsidered in future legislation. For example, a July 2018 report (the "Rutgers Report") by Will Irving, Michael L. Lahr, and Ray Caprio of the Edward J. Bloustein School of Planning and Public Policy at Rutgers, the State University of New Jersey, which analyzed data concerning Grow NJ awards approved by the EDA to date, found that the average cost in tax incentives per job incentivized by the formula approach was $55,888, while the average cost per job under the Camden alternative approach was

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$340,000—over six times more.[42] The Rutgers Report recommended that the Camden alternative approach "be revised to tie awards more closely to the employment created by these firms."[43]

Additionally, it should be noted that the "capital investment" definition in the statute, which, as described above, effectively operates to define the expenditures for which companies are eligible to receive recompense via tax credits, is extremely broad. The statute defines "capital investment" with respect to projects in Camden to include, among other things, any and all "development, redevelopment, and relocation costs."[44] The result is that a broad range of expenditures in Camden by Grow NJ beneficiary companies may be effectively reimbursed via tax credits—notably, including expenditures for which the public interest in state subsidization is debatable. For example, the new office tower on the Camden waterfront for which Conner Strong & Buckelew was approved for an $86 million award included a rooftop helipad, the construction of which is within the scope of the statutory "capital investment" definition. Whether Grow NJ was intended to enable the State to subsidize helipads for corporate executives can reasonably be questioned.

c) Expansion of Capital Expenditures Eligible for Tax Credits

As discussed above, the "capital investment" definition in the Grow NJ statute effectively operates to define the expenditures for which companies with projects in Camden are eligible to receive recompense via tax credits. It appears that Kevin Sheehan of Parker McCay had a role in amending the statute's "capital investment" definition in two ways apparently intended to benefit the firm's clients.[45]

First, Mr. Sheehan appears to have amended the definition to include, as an eligible expenditure, "pier, wharf, [or] bulkhead . . . construction or repair."[46] This amendment was likely intended to benefit several Parker McCay clients, including Conner Strong & Buckelew, that, as discussed in Section V(C)(4)(b) of this First Report, had plans to construct a new office tower on a pier on the Delaware River waterfront of Camden. As a result of this amendment, these clients would be allowed to receive tax credits for any such construction or repairs on the pier.

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[42] Rutgers Report at i–ii. The Rutgers Report is available on the EDA's website, at https://www.njeda.com/pdfs/NJEDA-Final-Incentives-Report_Governor.aspx.
[43] Rutgers Report at iii.
[44] *See* N.J. Stat. § 34:1B-243 ("capital investment" definition).
[45] In addition, it is notable that the "capital investment" definition was expanded to include expenditures on "professional services." However, the metadata does not reflect that Kevin Sheehan made that amendment.
[46] *See* N.J. Stat. § 34:1B-243 ("capital investment" definition).

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Second, Mr. Sheehan appears to have also amended the "capital investment" definition to include "site acquisition" as an eligible expenditure if purchased within 24 months prior to the Grow NJ application, thereby allowing the firm's clients with planned projects in Camden to potentially receive tax credits for real estate that the company purchased before even applying to the EDA for the tax incentives.[47] This amendment has a clear tension with the overarching purpose of tax-incentive programs, which are intended to incentivize companies to make decisions that they have not already made and would not make absent the incentive. This provision, by contrast, affords tax credits for company decisions already made—that is, real estate already purchased. Precisely because of this tension, the EDA's former President and Chief Operating Officer Tim Lizura testified at the Task Force's May 2, 2019 public hearing that this provision "was always a challenge to administer" and he "never really understood the policy behind it."[48]

d) Phantom Taxes in the Net Benefit Test

Under the Grow NJ Act, every tax-incentive award must be anticipated to "yield a net positive benefit to the State."[49] In this context, the "benefit to the State" means tax revenues collectible by the State as a result of the fruition of the project for which the tax incentives were awarded—that is, tax revenue that the State would not collect in the absence of the tax incentives. For example, consider construction work in New Jersey that would not occur unless tax incentives are provided. If the incentives are awarded and the construction is commenced, any taxes collected by the State as a result of such incentivized construction, such as property taxes on the developed property and sales taxes on the building materials used in the construction, are "benefits to the State." Because of this so-called "net benefit" requirement under the Grow NJ Act, tax incentives under the Program are sometimes said to effectively "pay for themselves." That is, if the statute operates as intended, the State will collect tax revenue at least in the amount that the State "spends" on tax incentives, meaning that there is no loss to the public fisc.

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[47] Although the text of this provision has been revised by subsequent statutory amendments, Mr. Sheehan's amendment remains in substance in the current law. *See* N.J. Stat. § 34:1B-243 (defining "capital investment" in pertinent part: "In addition to the foregoing, in a Garden State Growth Zone [including Camden], the following qualify as capital investment: . . . site acquisition if made within 24 months of application to the [EDA]").

[48] Hr'g Tr. (May 2, 2019) at 228:11-230:19. As for why the provision would allow tax credits for site acquisition up to two years prior to the Grow NJ application but not earlier periods, Mr. Lizura said that he did not know of a policy reason for the distinction. *Id*. at 233:6-14.

[49] N.J. Stat. § 34:1B-244(a)(3).

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However, the EOA 2013's amendments to the Grow NJ program included certain provisions that significantly undermined the net benefit requirement for projects in Camden. Pursuant to these provisions, the net benefit calculation "may utilize" the value of certain taxes that would otherwise accrue but were exempted from payment by operation of other provisions of law.[50] In other words, the Grow NJ Act was amended to provide that the net benefit calculation for projects in Camden may include "phantom taxes" as ostensible "benefits to the State" even if the State will never collect those taxes. As a result of these provisions, the "net positive benefit to the State" that is purportedly required by the law may be rendered illusory.[51]

The bill drafts in Microsoft Word format in the Task Force's possession, both dated June 21, 2013, do not contain these provisions, which were apparently not yet incorporated into the bill as of this date.[52] Therefore, the Task Force does not have a document with metadata that indicates the author of these provisions. However, the Task Force is in possession of email correspondence between government officials who were involved in the EOA 2013's drafting that refers to "the 'phantom tax' notion for NBT that Phil and Kevin laid out in [the] original bill draft."[53] Because Parker McCay represented numerous clients with project plans in Camden, these provisions would have allowed these companies to potentially receive large Grow NJ awards—pursuant to the Camden alternative approach provisions discussed above—without the State receiving a corresponding net positive benefit.[54]

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[50] N.J. Stat. § 34:1B-244(a)(3)(b).

[51] At the Task Force's May 2, 2019 public hearing, the EDA's former President and Chief Operating Officer Tim Lizura was asked whether these provisions "allowed projects to get through even though they weren't paying for themselves." Mr. Lizura responded, "I would say that's a pretty accurate statement." Hr'g Tr. (May 2, 2019) at 257:9-15.

[52] We have been advised that a law firm has additional versions of drafts of EOA 2013 from this time period. The Task Force has attempted to obtain these drafts through voluntary cooperation from that firm. To date, we have not been successful.

[53] Exhibit 3. The EDA's Tim Lizura, who received this email, testified concerning the email's reference to "Phil": "I assume that's Phil Norcross." Hr'g Tr. (May 2, 2019) at 251:3-19.

[54] Mr. Lizura testified that he recalled the following companies with approved Grow NJ awards as having benefited from the phantom tax provisions: Holtec International, Philadelphia 76ers, L.P., American Water (American Water Works Company, Inc., American Water Works Service Company, Inc., and American Water Enterprises, Inc.), Subaru of America, Inc., Conner Strong & Buckelew Companies, LLC, The Michaels Organization, LLC, NFI, L.P. When asked whether Parker McCay represented all of those companies, Mr. Lizura responded, "I recall they represent[ed] some, some role in most of those." Hr'g Tr. (May 2, 2019) at 257:16-258:14.

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e) The Material Factor Test Applicable to Camden Projects

For incentivized projects in most parts of New Jersey, it is indisputable that, for a company to receive Grow NJ tax incentives for existing jobs in New Jersey, those jobs must be at risk of leaving the State or being eliminated. This is clearly set out in the statutory text, which requires companies to establish that "but for" the provision of tax incentives, the jobs would be relocated out of state or eliminated:

> "[T]he business's chief executive officer, or equivalent officer, shall submit a certification to the [EDA] indicating: (1) that any existing full-time jobs are at risk of leaving the State or being eliminated; (2) that any projected creation or retention, as applicable, of new full-time jobs would not occur but for the provision of tax credits under the program; and (3) that the business's chief executive officer, or equivalent officer, has reviewed the information submitted to the [EDA] and that the representations contained therein are accurate . . . ."[55]

As discussed above, the Task Force reviewed the June 21, 2013 EOA 2013 bill drafts.[56] The metadata in these documents appear to show that Kevin Sheehan of Parker McCay amended the above-quoted language to add a provision expressly stating that the risk of an out-of-state relocation "shall not be required with respect to projects in [Camden]." Mr. Sheehan proposed to amend the provision as follows:

> "[T]he business's chief executive officer, or equivalent officer, shall submit a certification to the [EDA] indicating that: (i) any existing full-time jobs are at risk of leaving the State or being eliminated; (ii) that any projected creation, or retention as applicable, of new full-time jobs would not occur but for the provision of tax credits under the program; and, (iii) that the business's chief executive officer, or equivalent officer, has reviewed the information submitted to the [EDA] and that the representations contained therein are accurate, **provided however, item (i) shall not be required with respect to projects in [Camden]**. . . ."[57]

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[55] N.J. Stat. § 34:1B-244(d).
[56] Exhibits 1 and 2.
[57] Additionally, in the current version of the statute, there is also language that makes this provision apply to projects in Atlantic City as well as to projects in Camden. The Atlantic City language was

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(Emphasis added).

On Friday, June 21, 2013, at 8:12 PM, an aide to then-Governor Chris Christie, Colin Newman, who was involved in EOA 2013's drafting, sent an email to several senior EDA officials—Tim Lizura, Maureen Hassett, and Michele Brown—attaching a working draft of the bill containing the above-quoted amendment by Mr. Sheehan of Parker McCay.[58] Mr. Newman noted in the email that the bill draft presented certain "issues" that needed to be discussed over the weekend.[59] On Sunday, June 23, 2013, at 10:31 PM, Mr. Newman sent an email to Mr. Lizura and Ms. Hassett, stating that they needed to prepare "compromise language" with respect to the above-quoted provision.[60] Mr. Newman proposed language that would have restored the requirement that, for projects in Camden, there be a risk of out-of-state relocation to receive tax incentives for retaining jobs.[61] Throughout the morning and afternoon of Monday, June 24, 2013, Mr. Newman, Mr. Lizura, and Ms. Hassett proceeded to iteratively draft additional versions of proposed compromise language, while appearing to complain that the other side of the negotiations continued to produce "unsatisfactory" counterproposals.[62]

By the afternoon of June 24, 2013, the negotiating parties appear to have agreed to compromise language that rejected the "shall-not-be-required" language that Mr. Sheehan had drafted and replaced it with a "material factor" test that was ultimately enacted into law, and is still embodied in the version of the statute in force now. That material factor test is as follows:

> "[T]he business's chief executive officer, or equivalent officer, shall submit a certification to the [EDA] indicating: (1) that any existing full-time jobs are at risk of leaving the State or being eliminated; (2) that any projected creation or retention, as applicable, of new full-time jobs would not occur but for the provision of tax credits under the program; and (3) that the business's chief executive officer, or equivalent officer, has reviewed the information submitted to the [EDA] and that the representations contained therein are accurate, provided however, that **in satisfaction of the provisions of paragraphs (1) and (2) of this subsection, the certification**

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added in 2014 statutory amendments. Because the current discussion concerns EOA 2013's amendments, which did not yet apply to Atlantic City, we omit that language here.

[58] Exhibit 4.

[59] Exhibit 4.

[60] Exhibit 5.

[61] Exhibit 5.

[62] *See* Exhibits 6, 7, and 8.

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> **with respect to a project in [Camden[63]] . . . shall indicate that the provision of tax credits under the program is a material factor in the business decision to make a capital investment and locate in [Camden]** . . . ."

(Emphasis added).[64]

Thus, the statute provides that, for projects in Camden to be eligible for tax incentives, the company must be facing a "business decision" concerning where to "locate." One option must be Camden, and the provision of tax incentives must be a "material factor" in the company's decision to locate there. However, the statutory text *does not specify one way or the other* whether the "business decision" concerning the company's location (a) must be between Camden versus an out-of-state location or (b) may be between Camden versus another New Jersey location. No court has yet had occasion to interpret this clause and resolve this statutory ambiguity concerning whether tax incentives are available for intra-state relocations to Camden when no potential out-of-state relocation is considered. From the Task Force's perspective, the former interpretation—that is, that tax incentives for projects relocating to Camden, like tax incentives for projects relocating elsewhere, are available only if the company is considering a potential out-of-state location—is likely the better interpretation. This is so for at least two reasons. First, the New Jersey Supreme Court has repeatedly taught that "the furtherance of legislative purpose is the key to the interpretation of any statute,"[65] and here, the Grow NJ statute expressly states that a purpose of the program is to "preserve jobs that currently exist in New Jersey but which are in danger of being relocated outside of the State."[66] The statute does *not* say that its purpose is to incentivize the relocation of jobs to Camden from elsewhere in New Jersey, even if those jobs are not at risk of

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[63] The statutory text that is replaced here with the bracketed "Camden" notation for ease of readability is the following: "a Garden State Growth Zone that qualifies under the 'Municipal Rehabilitation and Economic Recovery Act,' P.L.2002, c. 43 (C.52:27BBB-1 et al.)." Camden is the only municipality that fits that definition, as it is "the only municipality affected by the provisions of the [Municipal Rehabilitation and Economic Recovery Act]." Fiscal Impact Statement for Assembly Bill No. 4375 (Jan. 4, 2010), https://www.njleg.state.nj.us/2008/Bills/A4500/4375_S1.HTM.

[64] N.J. Stat. § 34:1B-244(d).

[65] *GE Solid State, Inc. v. Dir., Div. of Taxation*, 132 N.J. 298, 308 (1993). *See also, e.g.*, *In re Young*, 202 N.J. 50, 64 (2010) (explaining that statutory interpretation must be intended to "effectuate the fundamental purpose for which the legislation was enacted").

[66] N.J. Stat. § 34:1B-244(a).

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leaving the State. It would further the statute's express purpose, therefore, to construe the out-of-state requirement that is applicable to projects in the rest of the State to also apply to Camden.[67] Second, if the statute were to be interpreted as intended to incentivize the relocation of jobs to Camden from other parts of New Jersey, a question would arise as to whether the statute would be unconstitutional because it would favor Camden over other parts of the State and, as such, arguably be an impermissible "private, special or local law."[68] Statutory interpretations that avoid such serious constitutional questions are typically favored.[69] For these reasons,[70] if a New Jersey court

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[67] *Cf. Murray v. Plainfield Rescue Squad*, 210 N.J. 581, 592 (2012) ("We do not view the statutory words in isolation but in context with related provisions so as to give sense to the legislation as a whole.").

[68] *See* N.J. Const., art. IV, § VII, ¶ 7 ("No general law shall embrace any provision of a private, special or local character.") and ¶ 9(6) ("The Legislature shall not pass any private, special or local laws . . . [r]elating to taxation or exemption therefrom."); *Mooney v. Bd. of Chosen Freeholders of Atl. Cty.*, 122 N.J. Super. 151, 154 (Law. Div.), *aff'd*, 125 N.J. Super. 271 (App. Div. 1973) ("[L]ocal and special laws rest on a false or deficient classification in that . . . they create preference and establish inequalities; they apply to persons, things or places possessed of certain qualities or situations, and exclude from their effect other persons, things or places which are not dissimilar in these respects.'") (internal quotation marks and citation omitted). While the Legislature may in some cases adopt special laws if there is prior public notice (¶ 8), the prohibition in ¶ 9(6) against special laws "[r]elating to taxation or exemption therefrom" is absolute.

[69] *See, e.g.*, *Silverman v. Berkson*, 141 N.J. 412, 417 (1995) ("Unless compelled to do otherwise, courts seek to avoid a statutory interpretation that might give rise to serious constitutional questions.").

[70] Additionally, it is also notable that, whether the EDA is applying the "material factor" test that is applicable to Camden or the "but for" test that is applicable to the rest of the State, in both cases the statute directs the EDA to consider the same evidence concerning the company's potential relocation sites: "When considering an application involving intra-State job transfers, the [EDA] shall require the business to submit the following information as part of its application: a full economic analysis of all locations under consideration by the business; all lease agreements, ownership documents, or substantially similar documentation for the business's current in-State locations; and all lease agreements, ownership documents, or substantially similar documentation for **the potential out-of-State location alternatives**, to the extent they exist. Based on this information, and any other information deemed relevant by the [EDA], the [EDA] shall independently verify and confirm, by way of making a factual finding by separate vote of the [EDA]'s board, the business's assertion that the jobs are actually at risk of leaving the State, and as to the date or dates at which the [EDA] expects that those jobs would actually leave the State, or, with respect to projects located in [Camden] . . ., the business's assertion that the provision of tax

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were to construe this "material factor" provision, the Task Force believes the court would more likely than not conclude that an out-of-state location is required for projects in Camden.[71] Putting our view aside, whatever the Legislature intended, any representations Grow NJ applicants made to the EDA concerning their potential out-of-state relocation were required to be truthful, so falsely stating that jobs were at risk of leaving the State and, accordingly, that an out-of-state alternative was under consideration would be highly problematic.[72]

In any event, whether or not a risk of an out-of-state relocation is strictly required under the statute for projects in Camden, it is indisputable, based on provisions of the Grow NJ Act and EOA 2013 separate and apart from those discussed here, that whether or not such an out-of-state relocation is contemplated is a critical factor bearing upon the potential size of any award. This is because of Grow NJ's "net benefits" requirement, which mandates that every Grow NJ award be anticipated to result in a net benefit to the State in terms of new tax revenue.[73] For companies relocating existing jobs from somewhere within New Jersey to Camden, those jobs create no new "benefit" to the State, since the "benefits" test is state wide and those jobs would yield no new tax

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credits under the program is a material factor in the business's decision to make a capital investment and locate in [Camden] . . . before a business may be awarded any tax credits under this section." N.J. Stat. § 34:1B-244(d) (emphasis added). If a potential out-of-state alternative location were not required for projects in Camden, it is difficult to understand why the statute directs the EDA to consider evidence of the company's "potential out-of-state location alternatives" ("to the extent they exist") in the same manner as if EDA were considering a project outside Camden, where there is no question that an out-of-state location alternative is required.

[71] The "material factor" provision applicable to Camden, in the Task Force's view, is likely best understood as intended to reduce the required showing for the at-risk nature of the jobs: outside Camden, the CEO has to certify that but for the tax incentives jobs would leave the State (that is, the tax incentives are a determinative factor in the company's decision); by contrast, in Camden, the CEO has to certify that the tax incentives are a material factor in locating the jobs in Camden rather than in another state (that is, the tax incentives are an important factor in the company's decision but are not necessarily determinative).

[72] *See* N.J. Stat. § 34:1B-244(d) (requiring an applicant's CEO or other equivalent officer to certify that he or she "has reviewed the information submitted to the [EDA] and that the representations contained therein are accurate"). For criminal penalties under New Jersey law potentially applicable to misrepresentations in connection with Grow NJ applications, *see* N.J. Stat. §§ 41:3-1 (perjury), 2C:28-2 (false swearing), 2C:28-3 (unsworn falsification), 2C:21-3(b) (fraud relating to public records), 2C:20-4 (theft by deception), 2C:21-7(h) (deceptive business practices).

[73] *See* N.J. Stat. § 34:1B-244(a)(3) (requiring Grow NJ awards to "yield a net positive benefit to the State").

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revenue.[74] Put another way, New Jersey accrues tax revenue from those jobs whether or not they are relocated, since in either case they are in the State. Based on this principle, when in-state jobs are relocated to Camden and no potential out-of-state alternative is contemplated, the "benefit" calculation is minimal, and the potential tax incentive award must be reduced as a result.[75] Thus, if a company falsely certified that its jobs were "at risk" of leaving the State—when they were not at risk—such a representation would likely affect the size of the company's potential award, and, as such, would surely be material.[76]

We hasten to note that the above discussion relates to the Grow NJ statute itself—not to the EDA's administration of the law, which is covered later in this First Report. Here, the Task Force notes that with respect to the "material factor" provision of the statute, there is a notable ambiguity, which, as shown by the evidence above, may have been by design—as a compromise between, on the one hand, those parties who advocated for the statute to expressly provide that a risk of out-of-state relocation "shall not be required" for projects in Camden, and, on the other hand, those parties who advocated for the statute to require a showing that jobs were at risk of out-of-state relocation.[77]

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[74] This principle, which is inherent in the notion of a state-wide "benefits" test, is expressly set out in EDA's regulations for Grow NJ, which provide in pertinent part: "Retained employees in a project in [Camden] . . . shall not be included [in the benefits calculation] unless the business demonstrates that the award of tax credits will be a material factor to retain the employees **in the State** . . . ." N.J. Admin. Code § 19:31-18.7(c) (emphasis added).

[75] This issue is discussed further below, in Section V(C)(2)(b) of this First Report.

[76] As EDA's former President and Chief Operating Officer Tim Lizura explained at the Task Force's May 2, 2019 public hearing, "the net benefit test was a statewide test, and that would suggest, or would then require that the jobs would be at risk of leaving New Jersey in order to include [the] economic impact of those jobs under the net benefit test. If there was not a risk of leaving the state, we would include all the other drivers of the net benefit test except the economic activity from the employees, which is the largest driver of the economic output." Hr'g Tr. (May 2, 2019) at 262:8-18).

[77] In 2014, this provision of the Grow NJ Act was again amended to provide that Atlantic City would be treated in the same manner as Camden. Therefore, under the current version of the statute, companies may be eligible for Grow NJ benefits when the tax incentives are a "material factor" in the company's decision to locate in either Camden or Atlantic City. The statutory ambiguity discussed in this section with respect to Camden applies likewise with respect to Atlantic City.

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2. Influence by Special Interests in EDA's Implementing Regulations for Grow NJ

After EOA 2013 was enacted in September of 2013, it fell to the EDA to promulgate regulations to implement the law's amendments to the Grow NJ program. As described previously, New Jersey law required the EDA to use a "notice-and-comment" process in connection with its issuance of such regulations—that is, to provide public notice of the regulations it was considering and to receive and consider comments from interested members of the public in response to such proposals. However, the Task Force has received information and documents that appear to show that—before the EDA publicly announced any proposed regulations—Kevin Sheehan of Parker McCay privately lobbied the agency to adopt provisions favorable to the firm's clients. At least one of these requests was incorporated in the EDA's first publicly proposed regulations, which the agency announced on January 6, 2014.

Grow NJ, as previously noted, generally excludes retail businesses from eligibility for tax incentives.[78] Parker McCay represented The Cooper Health System—the parent of Cooper University Hospital in Camden—in connection with its Grow NJ application. If the hospital were to be deemed a retail business, it would be ineligible for tax incentives under the statute. (From a policy perspective this exclusion is sensible, since a retail business—especially a hospital dedicated to serving a local community—is unlikely to make a business decision to move out of state absent tax incentives.) On December 10, 2013, Mr. Sheehan sent an email to the EDA's then President and Chief Operating Officer Tim Lizura: "[I]n reviewing the qualified business facility definition in the [regulations] that we discussed, my suggestion would be to add a sentence at the end of the definition to say: a university research hospital shall not be considered final point of sale retail. Thanks."[79] The EDA incorporated the request into its initial January 6, 2014 regulatory proposal as well as its final regulations adopted on December 15, 2014, and the provision remains in effect in the regulations in force now.[80] The Cooper Health System—deemed eligible for tax incentives pursuant to this regulation—would later be approved by the EDA for an approximately $40 million award. Meanwhile, the EDA does not appear to have disclosed that, outside of the public notice-

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[78] *See* N.J. Stat. § 34:1B-243 (generally excluding "business[es] that [are] . . . engaged in final point of sale retail" from the definition of the "qualified business facilit[ies]" that are eligible for tax incentives).
[79] Exhibit 9.
[80] *See* N.J. Admin. Code § 19:31-18.2 (in the "qualified business facility" definition, carving out "university research hospital[s]" from the scope of ineligible "business[es] . . . engaged in final point of sale retail business").

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and-comment period, its regulations had been amended in response to the request of a private party, apparently to assist a specific client.

3. Inadequate Statutory Requirements to Ensure Job Requirements Are Consistently Met

The current statutory requirements and EDA regulations governing reporting requirements and required annual jobs reports for companies to receive awards are inadequate to ensure that companies are consistently creating or retaining the required number of jobs and achieving the aims of Grow NJ. Based on the language of the regulations, a company need only submit an annual report, certified by the company's chief financial officer or equivalent, showing that it created or retained the required number of jobs for the last tax year before the credit amount is approved and issued. There is no additional certification requirement to ensure that these jobs are maintained to further the aims of economic growth and job creation. In essence, a company could create the number of jobs required in its agreement, certify, receive the first tenth of its overall credit, and then eliminate or fail to retain the required number of jobs immediately after receiving its credit while still retaining the award for the full year.

Indeed, in one instance, World Business Lenders, LLC ("WBL"), moved to New Jersey from another state in July 2016. WBL's award was contingent on its promise to bring a specific number of jobs into New Jersey, and its Incentive Agreement provided that it would remain in New Jersey for fifteen years. By October 2016, WBL had hired enough employees to meet the employment numbers set forth in its Incentive Agreement. WBL's submission to the EDA showed that it had satisfied the employment numbers set forth in its Incentive Agreement in October 2016. In the beginning of December 2016, the EDA certified to the Division of Taxation that the company was eligible for its overall tax credit certificate of approximately $16 million. At the beginning of January 2017, however, the company laid off a significant number of its employees, sending its job numbers well below the number required to continue to qualify for a tax-incentive grant. The EDA learned of the mass layoffs through news reports. The company subsequently submitted a report showing that it had met the required employment numbers for November and December 2016. Therefore, despite having seen indications that the company had terminated its employees after satisfying the requirements to receive its tax credit for 2016, the EDA asked the Division of Taxation to issue the company the first tenth of its overall credit, amounting to approximately $1.6 million. The company received this award even though it had been located in New Jersey for only six months, had submitted only three months of employment data, and had laid off a significant number of employees shortly after qualifying for the first year of its award.

The Task Force is still investigating this issue and has not reached any conclusion regarding the company's conduct or intent in connection with its application, and the company has maintained

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that it acted entirely in compliance with Grow NJ's requirements. Regardless, the Grow NJ regulations did not specifically require that the company prove that it maintained the agreed-upon number of jobs for a full twelve-months, did not require that it be located in New Jersey for a full year in order to receive a full year's award, and did not have a mechanism requiring that a company maintain a minimum number of jobs after the award was issued in order to retain its award. The company was not certified to receive the second tenth of its award in 2017 because it did not employ the required number of employees for that tax year.

V. EDA: THE ADMINISTRATION OF THE TAX-INCENTIVE PROGRAMS

In its examination of the EDA's implementation and administration of the Programs, the Task Force set out to: (1) further examine and assess the EDA's process and control failures, including in the EDA application-approval process, from pre-application through approval and certification; (2) evaluate the effectiveness of existing EDA policies and procedures relating to the roles and responsibilities of individual EDA officers, EDA staff training, and EDA officers' understanding of the purpose, implementation, requirements, and administration of the Grow NJ and ERG tax incentive programs; (3) assess the administration of the tax incentive programs and subsequent monitoring of grant recipients; and (4) determine whether or not external or internal pressures were brought to bear on the EDA in connection with its application approval, compliance, monitoring, and certification processes, as well as its rulemaking processes relating to the Programs.

A. Overview of the Application-Approval Process

In order to evaluate any problems relating to the Programs' design, implementation, or administration, the Task Force had to begin with an understanding of the relevant statutes and of the EDA's tax-incentive application and administration process, from application through the annual award of tax-incentive grants. As noted previously, the Task Force focused primarily on Grow NJ during the initial phase of its investigation. A high-level overview of the Grow NJ process is below:[81]

1. Pre-Approval Process: Application Review and Board Approval

Companies learn of EDA tax-incentive programs and make initial contact with the EDA through various channels. The EDA receives potential application referrals through a customer care telephone line, through the Business Action Center ("BAC"), which is housed within the New

[81] Although there is significant overlap between the Grow NJ and ERG processes, particularly in the pre-application through approval stages, the differences in the Grow NJ and ERG Program requirements result in divergent approaches to the administration of these Programs. We will provide an overview of the ERG process in a later report.

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Jersey Department of State, and through Choose New Jersey, a 501(c)(3) non-profit whose mandate is to act as the marketing arm of the State and attract out-of-state and international businesses to New Jersey. BAC personnel frequently work with EDA officers to attract and obtain program applicants, and the BAC has historically been the biggest driver of application lead referrals to the EDA. Separately, the EDA's Community Development Officers ("CDOs") and Business Development Officers ("BDOs")[82] are also charged with developing business relationships and recruiting potential applicants. Indeed, a BDO's year-end performance is evaluated, in part, on their outreach efforts as well as whether they have met yearly goals in the volume of applications submitted to the EDA. Potential applicants may also directly contact the EDA to obtain information about the Programs. In addition, applicants are often represented by consultants, lawyers, lobbyists, or real-estate agents, and those representatives may also reach out directly to EDA personnel prior to the submission of a tax-incentive application.

Before submitting a Program application, a potential applicant often has an initial meeting or conversation with EDA personnel—typically a BDO—in order to discuss the applicant's business, needs, and Program requirements. Potential applicants occasionally meet with members of the EDA's senior leadership team in addition to or in lieu of meeting with a BDO. Pre-application dialogue between Program applicants and the EDA is not required, but in practice, often precedes formal submission of a company application by weeks or months.

A company formally submits its application through the EDA's electronic application system. At that time, the company pays an application fee and a BDO is assigned to the application. Often, it is the same BDO that worked with the company pre-application. The BDO is responsible for conducting an initial review of the application and assisting the applicant—or "client"—in ensuring that the applicant has submitted all required documentation prior to transmittal of the application file to Underwriting. BDOs must consult their Program Manager and Managing Director for application reviews before the application is submitted to the Underwriting group.

During the underwriting phase, underwriters are responsible for conducting due diligence and vetting an application to ensure it sufficiently meets all Program requirements and to address any outstanding concerns. Although underwriters bear the primary responsibility for conducting due diligence and follow-up with applicants, they often include the assigned BDO in correspondence to the applicant as the face of the relationship. Among other factors, underwriters

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[82] These roles and titles within the EDA are now consolidated and currently all Community Development Officers ("CDOs") are now referred to as Business Development Officers ("BDOs"). For the sake of consistency, the Task Force's First Report will refer to both CDOs and BDOs at various times as BDOs.

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assess the applicant's submitted cost benefit analysis[83] and conduct the required net benefits analysis.[84] Underwriters are also responsible for drafting project summary memoranda, which are presented during "Project Review Meetings." At those meetings, the assigned underwriter presents the application to EDA personnel and members of the New Jersey Attorney General's Office. The EDA staff discusses and raises any issues or concerns related to the application, which the assigned underwriter answers or addresses directly with the applicant as follow-up.

After the Project Review meeting, the underwriter presents the application to the Incentive Committee of the EDA Board, after which the Incentive Committee either does or does not recommend an application for approval by the Board. Although an application may proceed to Board review without a recommendation by the Incentive Committee, more often, the applicant will withdraw its application if the Incentive Committee does not recommend approval.

If the Incentive Committee recommends that the EDA Board approve an application, the application is presented during an EDA Board meeting for approval. EDA Board meetings are conducted on a regular basis and are open to the public. Prior to the Board Meeting, EDA personnel provides the EDA Board with memoranda detailing the project applications that are subject to review and approval at the upcoming meeting. If the Board votes on an application and it is approved, the Governor has ten days to veto the approval. Board-approved projects are required to pay a non-refundable fee of 0.5% of the approved award amount, capped between $50,000 to $500,000, prior to final approval.

Depending on the complexity of the application, the full review process may last a number of months. EDA employees said that, in the early period of Grow NJ's administration, they often processed applications in one or two months, but now, although they can process more complete applications in as little as two months, it could take several months to a year to process others.

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[83] The EDA requires Grow NJ applicants to submit "Cost Benefit Analysis" (or "CBA") forms with their applications. These forms compare the costs of the applicant's proposed New Jersey site and the applicant's alternative site. The purpose of the form is to demonstrate that the applicant's proposed New Jersey location is more expensive than the alternative location—and thus, tax incentives are required to offset the higher costs.

[84] As discussed in further detail herein, the EDA conducts a net benefit analysis ("NBA") to determine that every Grow NJ award is anticipated to "yield a net positive benefit to the State" of at least 110%, with the exception of Camden, where the requirement is 100%.

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2. Post-Approval Process: Closing Services, Monitoring, and Certification

After Board approval, the EDA executes an approval letter and the project moves to Closing Services, during which a conditions of approval officer monitors the project to ensure that any conditions imposed on the project have been met. The conditions of approval, outlined in the approval letter, may include, for example, site plan approval, site control, committed project financing, eligible minimum capital investments, and updated status reports. Once the conditions have been met, Closing Services prepares an Incentive Agreement in consultation with the New Jersey Attorney General's Office. Once the Incentive Agreement is executed, a closing date is set. After closing, the company may receive a tax award the following year, provided it can certify that the project has met all the conditions of the Incentive Agreement in the prior year.

Once the closing process is complete and an Incentive Agreement has been executed, the project is transferred to the Portfolio Management and Compliance[85] group for monitoring and annual certification. Projects have three years to certify that they have met all the conditions and requirements of the Program and Incentive Agreement, with the possibility of up to two six-month extensions of time. Once a project certifies to the EDA that it has met all conditions and requirements of the Program and Incentive Agreement, the EDA's Portfolio Management and Compliance group then certifies the same to the Department of Treasury. The Treasury Department then issues the tax-incentive award. Projects are required to certify their compliance on an annual basis to obtain their tax-incentive award, which is distributed evenly in increments of 1/10th of the total award, across a ten-year period.

If the Portfolio Management and Compliance Group determines that a project is non-compliant with its Incentive Agreement or the Program requirements, the tax incentive award is subject to potential forfeiture, recapture, or recoupment.

B. EDA-Related Litigation

In the early stages of the Task Force's investigation, the Task Force discovered a whistleblower complaint, *Veyis Sucsuz v. New Jersey Economic Development Authority, John J. Rosenfeld, Michele Brown, Fred Cole, Anne Cardello, and John Does 1-10*,[86] filed on May 11, 2015 in New Jersey Superior Court, Mercer County, by a former EDA underwriter, Veyis "David" Sucsuz. Mr. Sucsuz was employed at the EDA for over ten years until his termination in September 2014. He began at the EDA as a legal assistant in lending services and later became an underwriter,

[85] The Portfolio Management and Compliance Group was reorganized and renamed in late 2018 and previously existed as the Finance & Development – Post-Closing Financial Services Group.
[86] No. MER-L-001083-15 (Super Ct., Mercer Cty. filed May 11, 2015).

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responsible for the review and processing of Grow NJ and ERG incentive award applications, among other incentive programs.

In his complaint, Mr. Sucsuz alleged employment discrimination claims in addition to claims that he witnessed misconduct in connection with Grow NJ and ERG incentive program approvals, and that he was fired when he resisted directives from senior management to alter or promote applications that should have otherwise been rejected. Among other claims of misconduct by both applicant companies and individuals within the EDA, Mr. Sucsuz alleged, both in his complaint and under oath in deposition testimony, that certain applicants to the Grow NJ Program provided fabricated or "phantom" out-of-state locations.[87] Mr. Sucsuz alleged that in some instances, applicants fabricated an alternate out-of-state location to conceal a pre-existing intention to locate or expand in New Jersey. Mr. Sucsuz alleged that such applicants were nevertheless approved for Grow NJ tax incentive grants. Mr. Sucsuz further alleged that he was directed by his supervisor to alter or manipulate cost inputs for the cost benefit analysis or net benefit test in order to qualify applicants that would not have otherwise qualified with the cost inputs provided. He alleged that when he refused to alter the cost inputs, his supervisor would do it himself.

The case ultimately went to jury trial, which began on April 30, 2018 and lasted eight days. The jury announced its verdict on May 10, 2018. While Mr. Sucsuz did not ultimately prevail on his retaliation claim, the jury unanimously found that Mr. Sucsuz had a reasonable belief that the EDA violated a law, rule or regulation in the processing of application for loans, grants and tax incentives, and had proven by a preponderance of the evidence that he performed a "whistleblowing" activity as defined by the New Jersey Conscientious Employee Protection Act ("CEPA").

Despite testimony at the May 2, 2019 hearing by a Senior Vice President of Operations for the EDA that Mr. Sucsuz's allegations "identif[ied] potential fraud or misrepresentation in the application[s] submitted to the EDA for tax incentive programs" and also "focused on the EDA's review and approval of tax incentive awards,"[88] the EDA took no action to investigate any of Mr. Sucsuz's whistleblower allegations. While the Task Force has taken no position on the accuracy

[87] As discussed in Section V(C)(2)(b) of this First Report, for incentivized projects in most parts of New Jersey, it is indisputable that, for a company to receive Grow NJ tax incentives for existing jobs in New Jersey, those jobs must be at risk of leaving the state or being eliminated. Thus, where jobs are not at risk of elimination, applicants must demonstrate an alternate out-of-state location. In any event, any proposed alternate out-of-state locations must be legitimate and comparable.
[88] Hr'g Tr. (May 2, 2019) at 58:18-59:2.

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or truthfulness of Mr. Sucsuz's allegations, the Task Force has taken steps to investigate Mr. Sucsuz's various claims, which will be detailed in a later report.[89]

We also found that the EDA lacks the proper internal controls with respect to the processing and review of internal whistleblower complaints. During the second day of the Task Force's public hearing, we heard testimony from a Senior Vice President of Operations at the EDA, Fred Cole, who admitted to a failure within the EDA to investigate a former EDA underwriter's whistleblower complaints regarding various failures within the EDA with respect to tax incentive applications. At the May 2, 2019 public hearing, Mr. Cole acknowledged that the whistleblower allegations implicated conduct related to the EDA's tax-incentive programs, specifically that the allegations "identif[ied] potential fraud or misrepresentation in the application submitted to the EDA for tax incentive awards" and "also focused on the EDA's review and approval of tax incentive awards."[90] Yet, Mr. Cole testified that neither he nor anyone else at the EDA conducted an internal investigation into the allegations of fraud and misconduct. The Task Force takes no position on the accuracy or truthfulness of the whistleblower allegations. However, the EDA's processes failed when it took no steps to investigate the whistleblower claims which, as Mr. Cole admitted, could have had merit and, if true, could have carried significant financial ramifications.

In addition to the EDA's failure to conduct an internal investigation into the former EDA employee's whistleblower allegations, the EDA further failed to disclose this litigation to the Office of the Comptroller during its 2018 audit despite an affirmative obligation to disclose pending claims and litigation against the EDA. Indeed, the EDA's failure to disclose occurred despite the fact that members of its senior leadership team were deposed shortly before and during the beginning stages of the Comptroller's audit in late 2017 and early 2018 and despite the fact that the trial took place in April 2018 while the Comptroller's audit was ongoing. In fact, at the conclusion of the Comptroller's audit on January 3, 2019, Mr. Cole signed a management representation letter to the Comptroller's office, representing that, for the ten years prior and through the close of the Comptroller's audit, the EDA was not aware of any allegations of fraud or suspected fraud affecting

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[89] During its investigation, the Task Force made several attempts to contact Mr. Sucsuz for testimony but was ultimately unsuccessful. The Task Force first attempted to obtain Mr. Sucsuz's voluntary testimony by contacting him through his former counsel; however, when Mr. Sucsuz failed to return the Task Force's requests to meet, the Task Force requested the issuance of a subpoena from Professor Chen. After several attempts to serve Mr. Sucsuz, the Task Force ultimately effectuated proper service of two subpoenas for both deposition and public hearing testimony on Mr. Sucsuz. He nevertheless failed to appear at both the date set for his deposition and the May 2, 2019 public hearing of the Task Force.

[90] Hr'g Tr. (May 2, 2019) at 58:18-59:2.

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the EDA received in communications from employees or former employees and had disclosed all details concerning any pending claims, assessments and litigation against the EDA of which the EDA was aware and which would have a significant impact on financial operations.[91] EDA representatives are unable to offer an explanation for their failure to disclose the whistleblower litigation and a basis for its false representations to the Comptroller that it had, in fact, disclosed all relevant and pending claims and litigation.

C. Initial Findings

1. Lack of Written Policies and/or Procedures

The Task Force sought to review all of the EDA's written policies and procedures relating to the Programs. In seeking that information, the Task Force discovered that in the immediate years following the passage of EOA 2013, from approximately 2013 through 2017, the EDA had virtually no written policies or procedures regarding its process for reviewing and approving applications.[92] Although some practices and procedures have recently been memorialized in written memoranda to senior leadership and the Board, the EDA continues to lack a sufficient set of formal written policies and procedures to disseminate to personnel and ensure a consistent application review and approval processes.

Furthermore, to the extent policies have been memorialized by the EDA, we do not believe, based on the inconsistency of responses received from EDA employees when asked about such documents, that those policy documents have been consistently and comprehensively distributed amongst EDA personnel. For example, several BDOs were unaware of existing BDO checklists or flowcharts when shown during interviews. Indeed, most of the current EDA employees interviewed did not recall reviewing or receiving a training manual, memorandum, or set of written policies relating to the EDA tax incentive program approval process.

The EDA also lacks sufficient written policies detailing the roles and responsibilities of specific positions within the EDA. The Task Force received a "Grow NJ Processing Steps" chart, which was finalized in April 2015, identifying the EDA employee responsible for each step in the Grow NJ application process. However, several of the EDA employees that the Task Force interviewed had never seen this document. Moreover, the chart does not provide detail or guidance

[91] Exhibit 10.
[92] The EDA does have a few written policies, including on the net benefit test and the factors (including the possibility an out-of-state location) affecting that test.

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on how to execute each step outlined and therefore does not provide guidance as to the roles and responsibilities for personnel.

The Task Force observed that BDOs and underwriters rely primarily on basic "checklists" implemented in 2014, which set forth the documentation required for a complete application. These checklists, however, do not provide guidance on how EDA personnel are expected to review or analyze required documentation, which would be more helpful to the guide the process. Rather, they require only that the BDOs and underwriters confirm that the Program applicant submitted required documentation before the application was transmitted to the Underwriting group. As indicated, they do not offer guidance on what is considered adequate documentation. It appears, moreover, that at least some EDA employees believed the documents listed on the checklists were not all required to proceed with an application: a senior underwriter responsible for ERG applications described the ERG checklist, which identified "Items required prior to submission to underwriting" as including both required items and items that would be "nice to have." That same underwriter told us that, for example, the Chief Executive Officer ("CEO") Certification is a "nice to have" item from this checklist, despite the clear regulatory requirement for a CEO Certification under the ERG Act.[93]

2. Failure to Comprehensively Train EDA Staff

The effect of the EDA's lack of written policies and procedures was exacerbated by its failure to comprehensively train its staff while onboarding and during promotions and role transfers, or on an ongoing basis. The EDA did not comprehensively train its staff regarding: (1) the requirements and responsibilities of roles within the EDA; (2) the Programs' requirements; (3) amendments to the Programs' requirements; and (4) the EDA's implementation of the Programs' requirements. Indeed, each of the employees the Task Force interviewed confirmed that he or she did not receive any formal training when onboarded to the EDA; they also did not receive any formal training following a promotion or transfer to a new role. Rather, training was "on the job" and involved shadowing senior management and/or colleagues. In some cases, employees stated that they were provided with the relevant statutes and instructed to "familiarize themselves" with the provisions.

EDA employees also did not receive comprehensive training regarding the statutory requirements of the Programs and the Programs' subsequent amendments. Some senior EDA employees recalled that, after the EOA 2013 was passed, employees attended a training seminar or

[93] The regulations governing ERG expressly require, as part of the Program's application submission requirements, a "written certification by the chief executive officer, or equivalent officer for North American operations." N.J. Admin. Code § 19:31-4.4.

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seminars with the New Jersey Attorney General's Office that provided an overview of the Programs and guidelines. However, all the interviewees indicated that the EDA did not provide subsequent trainings when new statutory amendments were passed. Although some EDA personnel recalled that senior leadership briefed EDA personnel regarding statutory and regulatory amendments and changes to the EDA's tax-incentive Programs during Pipeline Meetings, others indicated that although they might have received a copy of a regulatory amendment and had an opportunity to ask questions, they did not recall receiving formal notice or follow-up training when regulatory changes took place. Indeed, two senior underwriters stated that, when statutory or regulatory requirements were amended, underwriters simply reviewed the amended language and learned how to enforce the new amendments "on the job."

Furthermore, EDA personnel were not adequately trained to review and analyze information and documentary evidence applicants were required to submit. For example, employees did not receive training on how to review and identify problems with lease agreements, letters of intent, or requests for proposals that are consistently submitted with project applications to support proposed project locations. EDA employees generally seemed completely unaware of the kinds of documents a business would generate if it were seriously considering a move of its facilities to another state, and some appeared to be reluctant to "ask too many questions."[94] We discuss some examples of the impact of those failures in Section V(C)(4) of this First Report below.

Finally, given the critical importance of screening applications for potential misconduct, some training in fraud detection is critical for program underwriters. Not only did the Task Force determine that the EDA provided no such training at any time, up to the present, many EDA employees we interviewed expressed the view that their vetting required them to take information at "face value."

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[94] At the Task Force's May 2, 2019 public hearing, John Boyd, a principal at a corporate site selection firm in New Jersey, testified that for a relocation of several hundred office employees, companies typically conduct a serious analysis to select the ideal location. The process often includes meetings with employees from multiple departments (including accounting, legal, human resources, and communications), memoranda and reports, and multiple site visits. Mr. Boyd testified at the Task Force's hearing that he "agree[d]" that, to determine whether a company was sincere in its considerations of a potential relocation site, there should be "a lot of documentation of [the company's] deliberations" that "the company should be able to produce." *See* Hr'g Tr. (May 2, 2019) at 101:9-107:17.

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a) Inconsistent Understanding of Roles and Responsibilities

The EDA's failure to comprehensively train its staff has resulted in an inconsistent understanding of the roles and responsibilities of specific positions within the EDA. The Task Force observed that among the BDOs we interviewed, there was a broad range in the understanding of their responsibilities. All BDOs interviewed understood their role as business developers and advocates for the applicants or "clients." However, several BDOs expressed the belief that their review of applications did not require independent verification of information and required only "perusing the application" for "red flags" or "glaring errors" that would potentially disqualify an applicant. Their supervisors, on the other hand, expected their officers to also conduct preliminary due diligence on the submitted documentation and conduct independent diligence in the form of internet-based searches on the applicant, including the business, its senior leadership, and the applicant's exposure to legal risks. Unfortunately, because of a complete lack of policies concerning how to conduct internet and other public searches for such information and what to look for, the quality of such diligence varied from BDO to BDO, and application to application. Indeed, as noted above, we found important information through simple internet-based searches which BDOs missed completely, including potentially disqualifying information.[95] BDO supervisors expected BDOs to review application materials and address as many potential issues or questions in order to present a complete application to Underwriting. Although some BDOs believed their role was to both assist and scrutinize the applicant, all the BDOs understood that it was primarily the underwriter's responsibility to conduct due diligence, investigate, and verify information provided by the applicant.

Nearly all of the underwriters interviewed understood their responsibility to conduct due diligence and investigate and verify information applicants provided; however, at least one senior underwriter understood the role to be that of a "processor" who "checks off the boxes." The same underwriter believed that the underwriters needed to review applications to ensure the required documentation and materials had been submitted but did not need to assess whether applicants' representations were truthful. This approach is inconsistent with the underwriters' gatekeeping role: the underwriters are the primary means to ensuring that applications comply with the Programs' requirements.

[95] However, the Task Force did observe other instances where BDOs did perform sufficient due diligence and identified one company's failure to disclose on its application potentially relevant lawsuits. The EDA eventually resolved the initial non-disclosure with the company.

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b) Inconsistent Understanding of the Program Requirements Concerning Camden and Atlantic City

The EDA personnel interviewed thus far have, in some important areas, exhibited inconsistent, incomplete, or inaccurate understandings of certain Program requirements, specifically with respect to (a) the circumstances in which Grow NJ applicants are required to demonstrate a risk that their jobs may be relocated outside of New Jersey and (b) the effect such a relocation risk may have on the terms of any tax incentives award.

As discussed in Section IV(A)(1)(e) of this First Report, the Grow NJ Act expressly states that a "purpose of the [Grow NJ] program is . . . to preserve jobs that currently exist in New Jersey but which are in danger of being relocated outside of the State."[96] In most cases, Grow NJ applicants are indisputably required to demonstrate to the EDA, in order to qualify for tax incentives, that they are considering an out-of-state relocation. However, because of an ambiguity in the statute's text, it is arguable that tax incentives may be available (although only in a reduced amount, for reasons discussed below) for relocating existing New Jersey jobs to Camden or Atlantic City, even when no potential out-of-state relocation is contemplated.[97] The EDA has on one occasion approved tax incentives for a company that relocated from within New Jersey to Atlantic City even though that company was not contemplating a possible out-of-state relocation—thus, the company was approved for tax incentives even though its jobs were not "in danger of being relocated outside of the State."

Whether or not an out-of-state relocation is strictly required under the statute for projects in Camden or Atlantic City to receive tax incentives, it is indisputable, based on a separate provision of statute, that whether or not such an out-of-state relocation is contemplated is a critical factor bearing on, at a minimum, the potential size of any award. As discussed previously, the Grow NJ Act requires that every tax incentive award be anticipated to "yield a net positive benefit to the State."[98] In this context, the "benefit to the State" means tax revenues collectible by the State as a result of the fruition of the project for which the tax incentives were awarded—tax revenue, that is, that the State would not collect in the absence of the tax incentives. Under the statute, no tax incentive award under the Grow NJ program may be larger than the anticipated benefit to the State. If the anticipated benefit is smaller than the award that for which the applicant would otherwise be

[96] N.J. Stat. § 34:1B-244(a).
[97] As discussed previously, EOA 2013 introduced this provision with respect to Camden, and the statute was amended again in 2014 to have the provision apply to Atlantic City as well.
[98] N.J. Stat. § 34:1B-244(a)(3).

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eligible, then the award must be reduced. For example, if an applicant would otherwise be eligible for a $50 million award for a project in Camden, but the EDA anticipates that the project will yield only $10 million in resultant tax revenue to the State, then the applicant's award must be reduced to $10 million only rather than $50 million.

A company's certification that jobs are at risk of leaving the State—and thus that it is considering an out-of-state alternative—may have a critical and material effect on the net benefit test, particularly with respect to income taxes that accrue from employment. The net benefit test required by the Grow NJ Act is a statewide test that assesses benefits to the State as a whole—rather than to a particular locality within the State. When an applicant's jobs are already in New Jersey, any income taxes related to those jobs are factored into the net benefits calculation only if the jobs are at risk of being relocated out of state. There, the provision of tax incentives, which keeps the jobs in the State, provides a clear benefit to New Jersey. By contrast, if an applicant is not considering moving out of state, and a job will exist somewhere in New Jersey in any event, there can be no benefit to the State as a whole. Thus, the EDA's implementing regulations for Grow NJ provide that, for projects in Camden and Atlantic City, "[r]etained employees . . . shall not be included [in the net benefits calculation] unless the business demonstrates that the award of tax credits will be a material factor to retain the employees in the State . . . ."[99] This rule is also set forth in several EDA policy documents.

Some EDA employees demonstrated a limited understanding of these issues. At least two EDA employees believed that, as administered by the EDA, projects moving to Camden did have to show jobs were at risk of leaving the State.[100] Some were unclear about whether the possibility of an out-of-state relocation is strictly required as a matter of threshold eligibility (rather than a factor in award size) for projects in Camden or Atlantic City, and did not know whether the EDA had ever processed applications concerning projects in Camden or Atlantic City for which no potential out-of-state relocation was contemplated. Although the existence of a potential out-of-state relocation clearly has an effect on the net benefit test and, therefore, on the size of any potential

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[99] N.J. Admin. Code § 19:31-18.7(c).

[100] *See* Hr'g Tr. (May 2, 2019) at 135:9-20 (testimony of David Lawyer, the EDA's managing director of underwriting since May 2017: "Q. And for companies that were, at the time of their application, they were already in New Jersey, does every Grow applicant need to show that the jobs were at risk, as the program was administered, does every applicant have to show that the jobs were at risk of moving out of the state? A. That is my understanding. Q. And that is true even where an application proposes to move jobs intrastate from a city outside of Camden to Camden? A. That is my understanding, yes.").

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award, at least one EDA employee misapprehended this rule. Given that the risk of jobs leaving the State is a core element of the Grow NJ program, it is important for all EDA employees responsible for processing Grow NJ programs to fully understand the pertinent issues, and EDA employees should have a firmer understanding of them.

3. Due Diligence Failures

The Task Force has found that the EDA's due diligence practices in connection with review of applications have generally been insufficient. Program applicants are required to make a number of representations in connection with their applications, both about the applicant itself and about the circumstances under which they are seeking tax incentives. Because these representations are critical to determining whether the applicant is eligible for the tax incentives requested, it is important to conduct sufficient due diligence to detect fraud, misrepresentations, or error.

Many EDA employees we interviewed did not believe independent verification of an application's accuracy or truthfulness was warranted because the EDA required an applicant's CEO to certify under penalty of perjury that the representations contained in the application were accurate and that the CEO had taken steps to ensure that the application materials were complete. However, if the answers provided by an applicant are taken at face value, without any effort to cross-corroborate or verify through public sources, applicants could easily present and certify false, misleading, or inaccurate information to the EDA without consequence.

Some EDA employees stated that they conducted internet searches regarding applicants and their senior personnel to identify potential red flags and issues, but it appears that those searches, when conducted at all, were insufficiently broad and failed to identify key information that should have raised red flags or at least warranted follow-up questions to applicants. For example, the Grow NJ application requires applicants to state whether the applicant has ever been debarred by any state or federal governmental department, agency, or instrumentality. Under the EDA's regulations, such a debarment could constitute grounds for the EDA to deny an application for tax incentives.[101] One company, Holtec International, represented in its application—certified by its CEO—that it had no prior history of debarment.[102] In fact, however, Holtec had previously been debarred by the Tennessee Valley Authority, a congressionally chartered corporation of the United States. The EDA then approved Holtec for a $260 million award under Grow NJ. Had the EDA conducted cursory internet research, it could have found that Holtec's answer was inaccurate. Yet EDA

[101] N.J. Admin. Code § 19:30-2.2(a)(1)(10).
[102] *See* Exhibits 11 and 12.

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personnel failed to independently uncover Holtec's misrepresentation when it approved Holtec's award, one of the largest tax incentive awards in New Jersey history.[103]

Although Holtec's undisclosed debarment was potentially disqualifying, other examples abound where readily available information—if the EDA had found it—would have at least merited follow-up questions to program applicants. However, even more concerning were examples found where EDA personnel did, in fact, conduct internet searches that yielded red flags, including relevant lawsuits involving the company, but EDA failed to investigate and conduct further due diligence that could have uncovered material misrepresentations. For example, NFI, L.P. ("NFI"), submitted its Grow NJ application on October 24, 2016. It asserted that in exchange for Grow NJ tax incentives, it would continue to employ 670 employees in New Jersey rather than move the jobs to Philadelphia. NFI submitted a chart of affiliates identifying the related companies, which included NFI Industries, Inc., National Freight, Inc., and NFI Interactive Logistics, LLC. As part of its application, NFI was required to answer a series of background questions related to legal matters. The application asked whether the "applicant, any officers or directors of Applicant, or any Affiliates (collectively, the 'Controlled Group') [had] been found guilty, liable or responsible in any Legal Proceeding for any of the following violations or conduct." NFI answered "No" for each listed question, which included offenses indicating a lack of business integrity or honesty, such as fraud, and violations of the governing hours or labor, minimum wage standards, and prevailing wage standards laws. While the EDA may have a timeframe that it considers relevant for legal proceedings, the actual application does not indicate that a company should limit disclosures to a period of five or ten years. Therefore, each company is presumed to have disclosed all legal proceedings relevant to the disclosure questions regardless of whether EDA would find it impactful on a company's eligibility.

The Task Force has reviewed the application and full company file of NFI and found that the EDA was aware of at least three lawsuits related to NFI.[104] In its Grow NJ transmittal form,

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[103] Last month, Holtec acknowledged that it did not disclose its prior debarment in its application and sought to amend its application. The EDA has since suspended Holtec's tax-incentive award, pending further investigation.

[104] First, an Equal Employment Opportunity Commission action in which NFI paid $45,000 to settle gender-discrimination allegations about unequal pay; second, a Department of Labor action in which NFI was ordered to pay 350 workers over $1 million in back wages for misclassifying them as exempt from overtime; and third, a Department of Labor action in which NFI was ordered to reinstate a trucker and pay him $276,870 after he alleged he was fired for refusing to make a trip that would have violated federal "hours of service" restrictions.

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which is an internal request for application review, an EDA BDO, listed four articles highlighting these three lawsuits under the section "Google Search of Applicants/Owners." Our review of correspondence indicates that on October 24, 2016, the EDA BDO sent an email to Mr. Sheehan of Parker McCay, who represented NFI, asking for an explanation and status of the three cases she found based on her internet search. On October 31, 2016, Mr. Sheehan responded with a brief explanation and stated that NFI disputed each claim but settled "to avoid protracted and costly litigation." The EDA BDO referred the issue and lawsuits to an EDA Senior Legislative Officer. In her correspondence, the EDA BDO highlighted for the EDA Legislative Officer that NFI answered "No" for the legal questions on their application. Based on a review of the correspondence, it appears that the EDA Legislative Officer directed the EDA BDO to request the settlement agreements from Mr. Sheehan and had further communications with Mr. Sheehan regarding details and his initial concerns regarding lawsuits involving NFI.

While the Task Force appreciates that the EDA BDO conducted initial diligence, it believes that further diligence would have unveiled a criminal conviction and guilty plea by affiliate Interactive Logistics, Inc. d/b/a NFI Interactive Logistics, Inc. and at least two additional legal proceedings.[105] The Task Force reviewed publicly available documents indicating that in November 2005, an NFI-related entity, Interactive Logistics, Inc. d/b/a NFI Interactive Logistics, Inc., pled guilty to three counts of wire fraud for defrauding Anheuser-Busch.[106] In addition, the Task Force reviewed publicly available documents related to lawsuits alleging violations of wage and hours laws. The Task Force finds this concerning on numerous grounds. It further highlights potential misrepresentations by NFI, and Sidney Brown, NFI's CEO who certified on its behalf, that all information contained within the company's Grow NJ application was true. Second, it is concerning that—after the EDA questioned Mr. Sheehan and NFI about the discovered lawsuits—neither he nor Brown was forthcoming about the criminal conviction or additional lawsuits, especially those of a nature required to be disclosed on the EDA application. Finally, from an EDA perspective, the Task Force believes that in-depth due diligence would have found the publicly available lawsuits. While the EDA Legislative Officer identified the need to review the settlement agreements in the lawsuits that were found, neither he nor the EDA BDO seemed appropriately concerned that at the crux of the matter, NFI's application contained potential misrepresentations

[105] *Interactive Logistics, Inc. v. Markel Insurance Co.,* No. 08-CV-1834 (D.N.J.); *Brime v. Eckenrode and Interactive Logistics, LLC*, No. 08-CV-0095 (E.D.V.A.) (previously captioned *Brime v. Eckenrode and Interactive Logistics, Inc. t/a National Freight, Inc.*).
[106] *United States v. Interactive Logistics, Inc.,* No. 05-CR-00872 (D.N.J.); *see* Exhibit 13.

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and a potentially fraudulent CEO certification. Even more, despite learning this, the EDA approved NFI's application for an approximately $80 million award.

4. Deficiencies in Assessing Applicants' Alternative Relocation Sites

The Task Force has investigated applicants' consideration of locations outside of New Jersey. Because a core goal of the Grow NJ program is "to preserve jobs that currently exist in New Jersey but which are in danger of being relocated outside of the State,"[107] Grow NJ applicants are required to provide information about the locations in New Jersey and other states to which they are considering relocating.[108] The Task Force's investigation to date has found clear deficiencies in the EDA's evaluation of applicant submissions about these alternative sites. In some instances, Grow NJ applicants have made representations about a potential out-of-state alternative site that should have raised serious red flags about whether the applicant genuinely intended to move out of state, but the EDA failed to take any action to investigate the issue.

The Task Force has examined the EDA's processing of several applications of Program awardees thus far, and that investigation is ongoing. The Task Force selected certain applications to prioritize for investigation if it received information about red flags in connection with a particular application or applicant—for example, if a whistleblower indicated that there were potential concerns with a company's application or compliance with Program requirements. In some instances, however, the Task Force did not initially intend to include certain companies in its priority review, but information arising during the Task Force's investigation alerted it to potential issues that should be further examined.

As noted previously, the draft versions of the EOA 2013 that included revisions from Parker McCay were, from the Task Force's perspective, a very significant red flag. The Task Force remains skeptical that a company whose lobbyist had placed special provisions for its benefit in the tax-incentive legislation would have a legitimate business plan to move jobs to a different state. Indeed, three of these companies—Conner Strong & Buckelew Companies, LLC ("CSB"), The Michaels Organization, LLC ("TMO"), and NFI—had publicly committed to moving to Camden on September 24, 2015—thirteen months prior to their Grow NJ applications, which would seem

[107] N.J. Stat. § 34:1B-244(a).
[108] N.J. Stat. § 34:1B-244(d) ("When considering an application involving intra-State job transfers, the authority shall require the business to submit the following information as part of its application: a full economic analysis of all locations under consideration by the business; all lease agreements, ownership documents, or substantially similar documentation for the business's current in-State locations; and all lease agreements, ownership documents, or substantially similar documentation for the potential out-of-State location alternatives, to the extent they exist.").

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to directly belie their claim that they were considering an out-of-state move. Yet, although the Parker McCay-edited version of the EOA 2013 had, we have determined, been shared with the EDA's then President and Chief Operating Officer, Tim Lizura, we saw no evidence that Mr. Lizura considered these applications with any skepticism or alerted the BDOs and underwriters reviewing the applications to apply any heightened scrutiny themselves. We thus worried that the process may have been compromised.[109] We therefore made our review of the EDA's oversight of some of these applications a key priority.

To compound our concerns, on March 11, 2019, the Executive Chairman of CSB and member of the Board of Trustees of The Cooper Health System ("Cooper Health"), George Norcross, III, published an Op-Ed on *NJ.com*. In the Op-Ed, Mr. Norcross stated, among other things, that the Programs' tax credits were intended to "convince firms to move to Camden," but "were **not intended** to entice firms that were leaving the state to remain." (Emphasis added).[110] Mr. Norcross's contention caught the Task Force's attention because, in point of fact, every application for an in-state company that proposed a move to Camden did, in fact, certify that jobs were "at risk" of leaving the State (except one that had planned to eliminate jobs if denied tax incentives), including applications from entities with affiliations to Mr. Norcross, including CSB and Cooper Health.[111] We also learned that TMO and NFI were affiliated with Mr. Norcross in that their applications were related to CSB's application. The Op-Ed thus raised a concern about whether any of these companies had not, in fact, been considering moving out of the State at the time they applied for tax incentives under Grow NJ. The Task Force decided to review the applications for those companies and—even on a cursory review—additional concerns arose, and the Task Force determined that an examination of the EDA's oversight of these applications was appropriate.

Thus, we reviewed the applications of Cooper Health, CSB, TMO, and NFI, to examine whether the EDA gave any meaningful scrutiny to their certifications that jobs were at risk of leaving New Jersey and whether they had viable out-of-state locations that were bona fide, suitable,

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[109] To date, we have found no direct evidence that Mr. Lizura's actions and inactions were motivated by any corrupt intent.

[110] George E. Norcross, III, *George Norcross: We need tax incentives to continue to rebuild Camden*, NJ.COM, March 11, 2019, http://s.nj.com/okKoUPg.

[111] Although Cooper Health's application indicated that jobs were not at risk of leaving the State, it subsequently informed the EDA during the course of EDA's processing of its application that—in fact—it was considering an out-of-state move to Philadelphia. These circumstances are described more fully below. The EDA did not require Cooper Health to submit a revised application, nor did it require a new certification from Cooper Health's CEO.

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and available.[112] After conducting this review, we found that the EDA's scrutiny of these four entities' applications was inadequate in several material respects and that, as a result, the EDA failed to discover significant problems with those applications. We describe below EDA's deficiencies in assessing these four applications.

a) The Cooper Health System

On November 7, 2014, Cooper Health applied to the EDA for tax incentives under the Grow NJ program. Just over a month later, the EDA approved Cooper Health for a tax-incentive award of $39,990,000, in exchange for Cooper Health's relocation of certain back-office operations from various existing sites in Cherry Hill and Mt. Laurel, New Jersey to Camden, New Jersey. During the EDA's processing of Cooper Health's Grow NJ application, Cooper Health represented to the EDA that it was considering relocating its operations to Philadelphia, Pennsylvania as an alternative to Camden. Based on this representation, an internal EDA memorandum recommended awarding the tax incentives to Cooper Health to "make New Jersey more competitive." However, there is significant evidence, described below, that Cooper Health's purported alternative location in Philadelphia was illusory, and the EDA failed to sufficiently investigate that possibility based on the information in its possession.

Cooper Health's tax credits were for its relocation of certain administrative functions to One Federal Street, Camden, New Jersey, in a building often referred to as the "L-3 Building." Internal Cooper Health documents indicate that Cooper Health favored the L-3 Building in Camden as a relocation site as early as March 2014, months before its November 2014 application for tax incentives: on March 28, 2014, Douglas Shirley, Cooper Health's CFO, sent an email to John Sheridan, Cooper Health's President and CEO: "I have the proposal . . . and it is very rich! From a cash flow and balance sheet [sic] the L-3 is the best deal by a long shot. No other option can touch it, so you need to be okay with this option before we go out with it."[113] In addition, an internal Cooper Health document dated April 1, 2014, entitled "Potential Cooper Office Options," contains a chart of three possibilities for Cooper Health's office, including the L-3 Building in Camden and two other potential locations—both also in Camden.[114] The chart does not list any potential Philadelphia location. The EDA did not request contemporary business records from Cooper Health concerning relocations it was considering, so it did not have the benefit of these documents.

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[112] The Task Force has examined several other applications for these same purposes but has not found other instances—at this stage—where serious concerns were apparent.
[113] Exhibit 14.
[114] Exhibit 15.

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When Cooper Health initially applied to the EDA for tax incentives on November 7, 2014, it did not claim that it was considering relocating out of state. The application asked: "Are any jobs listed in the application at risk of being located outside of New Jersey?" Cooper Health answered "No."[115]

On November 8, 2014, the day after Cooper Health's application was filed, Cooper Health's representative, Kevin Sheehan of the Parker McCay law and lobbying firm, sent an email to an EDA employee that processes Grow NJ applications, copying EDA's Tim Lizura, to "give . . . a heads up that Cooper Hospital filed its GrowNJ application." Mr. Sheehan added, "As you review the application, if you need anything, let me know."[116]

A few days later, on November 10, 2014, the EDA employee responded to Mr. Sheehan with a list of several items the EDA needed, including a completed "Cost Benefit Analysis" (or "CBA") form.[117] The EDA's CBA forms are used by Grow NJ applicants to list certain information about the potential relocation sites the applicant is considering, and to show the difference in costs between, on the one hand, the more expensive New Jersey location for which the applicant is seeking tax incentives, and, on the other hand, the less expensive alternative location that the applicant will ostensibly relocate to if denied tax incentives in New Jersey. Responding to the EDA employee's request for a CBA form, Cooper Health's Vice President of Real Estate and Facilities, Andrew Bush, copying Kevin Sheehan, submitted to EDA on November 11, 2014, a CBA form that compared the costs of the L-3 Building in Camden, for which Cooper Health sought tax incentives, to the costs of Cooper Health's existing facilities in Cherry Hill and Mt. Laurel, New Jersey—not to the costs of any out-of-state alternative site.[118] In other words, the CBA form was consistent with Cooper Health's representation on its application that no jobs were at risk of being relocated outside of New Jersey, since the CBA listed only in-state locations as under consideration.

Two days later, on November 13, 2014, the EDA employee sent an email to Parker McCay's Mr. Sheehan: "I need to talk to you about Cooper, what time do you have today or tomorrow to talk?"[119] Mr. Sheehan responded later that day: "I have [sic] here for the rest of the day today. Let me know what time works for you."[120] Later that night, Mr. Sheehan wrote to the EDA employee

[115] Exhibit 16.
[116] Exhibit 17.
[117] Exhibit 17.
[118] Exhibit 17.
[119] Exhibit 18.
[120] Exhibit 18.

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again, under the subject line "Cost benefit." Mr. Sheehan wrote: "They are working on it. Will get to you ASAP."[121]

Several days later, on November 18, 2014, Mr. Sheehan sent an email to the EDA employee with an updated CBA form for the Cooper Health application.[122] That revised form compared the costs of the L-3 Building in Camden not, as previously, to the costs of Cooper Health's existing locations in New Jersey, but instead to the costs of a claimed alternative location at 1900 Market Street in Philadelphia.[123] The CBA form stated that the purported 1900 Market Street location was 120,000 sq. ft. and cost $23.50 per sq. ft. to rent.[124] In other words, the revised CBA form effectively communicated to the EDA that Cooper Health was considering potential relocation sites in Camden or in Philadelphia. The Task Force interviewed the EDA employee who had these communications with Cooper Health and its representative, Mr. Sheehan. The EDA employee said that he did not recall the phone call with Mr. Sheehan, but he insisted that he would not have suggested to Cooper Health that it should claim to be considering an out-of-state relocation when it was not sincerely considering one. The EDA employee stated that he believed Cooper Health was in fact considering an out-of-state relocation.

Once all necessary documents for Cooper Health's Grow NJ application were submitted, the application was transferred to an EDA underwriter. On November 24, 2014, the EDA underwriter assigned to the application sent an email to Mr. Bush seeking "back-up on the proposed terms for each of the locations, NJ and PA, ie term sheets, letters of intent and/or draft lease agreements."[125] The underwriter, in other words, asked Cooper Health to provide documentation of the Camden and Philadelphia locations that purportedly were under consideration for relocation.

Several days later, on December 1, 2014, Cooper Health's Mr. Bush wrote to the EDA underwriter: "Sorry for the delay in the response. . . . I am touring alternate locations in PA on Wednesday and hope to have term sheets by the end of the week."[126] The underwriter responded: "Thanks, it is very important that I have some back-up to the lease terms as presented in the Cost Benefit analysis – it's all verbal at this point?"[127] Mr. Bush replied: "All quoted numbers are verbal

[121] Exhibit 19.
[122] Exhibit 20.
[123] Exhibit 20.
[124] Exhibit 20.
[125] Exhibit 21.
[126] Exhibit 21.
[127] Exhibit 22.

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from prospective landlords in Pennsylvania. I expect to have proposals to justify the numbers by the end of the week."[128]

On December 5, 2014, Mr. Bush sent the EDA underwriter, copying the EDA employee who had previously communicated with Cooper Health, and Parker McCay's Mr. Sheehan, a lease proposal from a real estate broker, dated that same day, for space in Centre Square in Philadelphia.[129] The proposal was for 113,756 sq. ft. in the building at 1500 Market Street, in Philadelphia's Centre Square, offered for either $22 or $24.75 per rentable sq. ft. depending on the terms of the lease. Mr. Bush explained in his cover email that the lease proposal was from a prospective Philadelphia landlord, and noted that "**[t]he terms are slightly more aggressive than those presented in the cost benefit analysis meaning that there is more of a burden to Cooper to remain in NJ**." (Emphasis added).[130] The Task Force interviewed the EDA employees who received this email from Mr. Bush. Both EDA employees told the Task Force that, based on Mr. Bush's representation that there was a "burden to Cooper to remain in NJ" because of the purported cost savings from relocating to Philadelphia, Cooper Health was sincerely considering relocating there.[131]

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[128] Exhibit 22. The Task Force has interviewed both the BDO and the underwriter responsible for the Cooper Health application. Both have indicated, credibly in our view, that they believed Cooper Health's representations that it was considering an out-of-state location as an alternative to Camden. Although Cooper Health has now publicly asserted that "the EDA, not Cooper, initiated requests for comparable leases of Philadelphia properties," both have denied this assertion. *See* Thomas W. Rubino, *Cooper Health official says the company's tax incentive award is appropriate, justified and legitimate*, NJ.COM, June 12, 2019, https://www.nj.com/opinion/2019/06/cooper-health-official-says-the-companys-tax-incentive-award-is-appropriate-justified-and-legitimate.html.
[129] Exhibit 23.
[130] Exhibit 23.
[131] Cooper Health's CEO certification, signed by the health system's CEO, Adrienne Kirby, was dated November 11, 2014—that is, prior to Cooper Health's November 18, 2014 submission of the CBA form with a purported Philadelphia alternative location at 1900 Market Street, and also prior to Cooper Health's December 5, 2014 submission of the lease proposal for 1500 Market Street in Philadelphia. Cooper Health did not submit a new CEO certification to EDA after it changed its application in this respect. Because Cooper Health has declined to cooperate with the Task Force's investigation, the Task Force has been unable to determine what Ms. Kirby did or did not know or believe concerning Cooper Health's relocation deliberations at the time she executed the certification.

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The EDA underwriter prepared a Confidential Memorandum of Analysis, dated December 9, 2014.[132] The memorandum stated that Cooper Health had demonstrated that "rental costs in Camden are higher than leasing comparable space in Philadelphia, PA . . . . As a result, [Cooper Health] has applied for Grow NJ tax credits to offset these costs and make New Jersey more competitive."[133] In the "Conclusions" section of the memorandum, the underwriter stated that Cooper Health's jobs were "at risk of being located outside of New Jersey" and that the grant of tax credits under the Grow NJ program would be "a material factor in the company's decision."[134] The EDA underwriter also prepared a Project Summary memorandum, which similarly stated that Cooper Health was considering alternative relocation sites in Camden and Philadelphia, that hundreds of New Jersey jobs were "at risk of being located outside the State," and that Grow NJ tax credits would be "a material factor in the applicant's decision to make a capital investment and locate in Camden."[135] Under the "Conditions of Approval" section of the memorandum, it stated as Condition No. 1 that Cooper Health "has not . . . committed to remain in New Jersey."[136] The memorandum concluded by recommending that EDA's Board "approve the proposed Grow New Jersey grant to encourage Cooper Health System to locate in Camden."[137] The memoranda were provided to EDA's Board and, on December 9, 2014, the Board voted to approve Cooper Health to receive almost $40 million in tax incentives.

The Task Force has found evidence that the claimed alternative site in Philadelphia was not a genuine alternative site but, rather, was created solely for the purpose of submitting evidence of an alternative site to the EDA, thereby bolstering Cooper Health's claim for tax incentives. On November 25, the day after the EDA underwriter had sent an email to Cooper Health's Andrew Bush asking for "back-up" for the locations described on Cooper Health's CBA form, including the Philadelphia location, Mr. Bush emailed a real estate broker, Jon Sarkisian at the CBRE brokerage firm, under the subject line "favor."[138] Mr. Bush's email asked the broker to produce a term sheet for a "credible" rental location in Philadelphia that would match the space (120,000 sq. ft.) and cost

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[132] Exhibit 24.
[133] Exhibit 24.
[134] Exhibit 24.
[135] Exhibit 25.
[136] Exhibit 25.
[137] Exhibit 25.
[138] Exhibit 26. The Task Force notes that CBRE has been entirely cooperative with the Task Force's investigation to date. The Task Force has no reason to believe that anybody at CBRE other than the persons named in this First Report had any awareness of or improper involvement in the matters discussed herein.

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($23.50 per rentable sq. ft.) specifications of the Philadelphia location described in the CBA that Cooper Health had submitted to the EDA on November 18, 2014:

> As part of our EDA application we need a term sheet for a potential location outside of NJ.
>
> I need a **credible location that is LESS expensive than L3**. I think that Center Sq may be the right comp – the building is listed by CBRE Given that this building is within the CBRE family – can you get me a term sheet for 120k sf? **Quietly? No probability of us moving to Center Sq, so I don't want to make too much noise**
>
> I need a full service number of $24/sf or less to make the numbers work. Space can be as-is for 10 or 15 year term.
>
> Let me know
>
> Thanks
>
> Andy

(Emphasis added).[139] The obvious reference is that Mr. Bush was asking Mr. Sarkisian to provide a sham term sheet that could be supplied to the EDA as evidence of its bona fide intent to relocate outside New Jersey, when in fact Cooper Health had no such intention.

Although obviously the EDA was not copied on that email, Cooper Health's application file contained numerous red flags that should have called into question the sincerity of its statement that it was considering relocating to Philadelphia and that the cost differential between the two proposed locations presented a "burden to Cooper to remain in NJ."[140] Cooper Health's initial application did not claim any possibility of an out-of-state relocation—and, indeed, expressly disclaimed the possibility. Only after the application was submitted to the EDA did Cooper Health provide purported evidence of an out-of-state location and claim that there was a "burden . . . to remain in NJ." Even at that point, Cooper Health made inconsistent representations about the Philadelphia site in question, first citing one address (1900 Market Street), and then citing another (1500 Market

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[139] After Mr. Bush sent the request to Mr. Sarkisian for a "credible" location, Mr. Sarkisian responded later that day, noting that he had received the email as well as a voicemail from Mr. Bush. Mr. Sarkisian added, "I like [sic] to speak to you the numbers may not come in the area that you thought. Call me in the office tomorrow." Mr. Bush responded, "Will do." Exhibit 26.
[140] Exhibit 23.

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Street). Those facts should have alerted the EDA underwriter to a potential problem, prompting additional diligence. However, the EDA failed to further investigate the facts to ensure that Cooper Health was genuinely considering relocating to Philadelphia, and that the location was bona fide, suitable, and available.

The EDA Board approved Cooper Health for an almost $40 million award on December 9, 2014.[141] The Task Force requested that the EDA recalculate the award that Cooper Health could have received if it had communicated to the EDA, as it had communicated to the real estate broker, that there was "[n]o probability"[142] of Cooper Health relocating to Philadelphia instead of Camden. Based on a recalculated net benefits analysis, the EDA concluded that Cooper Health would have qualified for only a $7.15 million award at most. Therefore, the failures in the EDA's processing of Cooper Health's Grow NJ application appear to have resulted in over $32 million in improperly approved tax incentives, putting aside the potential ramifications of Mr. Bush's apparent misrepresentation.

b) Conner Strong & Buckelew, The Michaels Organization, and NFI

CSB, TMO, and NFI submitted Grow NJ applications on October 24, 2016.[143] The three companies sought tax incentives in connection with joint plans to move into a new office tower on the Delaware River waterfront of Camden, New Jersey (the "Camden Tower"). Floors 15 through 18 of the Camden Tower (110,161 sq. ft.) were allocated to CSB, floors 12 through 14 (101,511 sq. ft.) were allocated to TMO, and floors 9 through 11 (101,511 sq. ft.) were allocated to NFI. The Camden Tower was to be constructed by the Liberty Property Trust development firm.

i) Background Context

Although CSB, TMO, and NFI submitted their Grow NJ applications to the EDA in October 2016, the EDA was aware of their plans to relocate to Camden long before then.

In September 2014, more than two years before the companies filed their applications, senior EDA management held a meeting with Philip Norcross of Parker McCay and several

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[141] Cooper Health could have potentially qualified for a larger award, but during EDA's processing of the application, Cooper Health removed a number of jobs from the application to keep the award under $40 million. Under EDA policy, awards over $40 million require additional scrutiny and processing time.
[142] Exhibit 26.
[143] Exhibits 27, 28, and 29.

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representatives from Liberty Property Trust. The purpose of the meeting, as described in an email setting it up, was to discuss "a large office building on the Camden Waterfront."[144]

A year later, on September 24, 2015, CSB's Executive Chairman, George E. Norcross, III, sent an email attaching a press release to the EDA's then President and Chief Operating Officer Tim Lizura discussing Liberty Property Trust's plans for the Camden waterfront, including the Camden Tower. The press release listed "local leaders who have **committed** to investing in the project either personally or through their firms," including "George E. Norcross, III, Executive Chairman, Conner Strong & Buckelew," "John O'Donnell, President, The Michael's Organization," and "Sidney Brown, Chief Executive Officer, NFI, and his family." (Emphasis added).[145]

That same day, then-Governor Chris Christie, then-Mayor Dana Redd, and others hosted a major press conference announcing the Camden waterfront development at the Camden Aquarium. George Norcross attended the event. At the event, a reporter for *NJTV News* asked Mr. Norcross, "It's been reported that you're going to put $50 million into the project, is that true?" He responded, "It's absolutely true. I **committed** to do this when I was trying to persuade one of the biggest real estate concerns in the country to become part of this effort, and we all thought that was going to be a credible act, and we're putting our money where our mouths are, and we're looking forward to being a part of it." (Emphasis added).[146] Press coverage around that time indicated that CSB, TMO, and NFI were expected to relocate to the new Camden development.[147]

Internal emails from the EDA show that Mr. Lizura attended the press event, at which he spoke to at least one reporter and one representative from Liberty Property Trust, the developer of the project.[148] But, later, when the companies were preparing their applications for tax incentives

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[144] Exhibit 30.
[145] Exhibit 31.
[146] *See* Michael Aron, *Christie Announces Historic $700 Million Redevelopment Project in Camden*, NJTV NEWS, Sept. 24, 2015, https://www.njtvonline.org/news/video/christie-announces-historic-700-million-redevelopment-project-in-camden/ (transcription from video).
[147] *See, e.g.*, Allison Steele, *Plans for Vast New Development on Camden Waterfront*, PHILA. INQUIRER, Sept. 24, 2015, https://www.inquirer.com/philly/business/20150924_Top_developer_to_announce_Camden_waterfront_project.html (reporting, based on an anonymous source, that CSB was "considering moving its headquarters into the development" and TMO and NFI were also "expected to join the project").
[148] Mr. Lizura sent an email to several EDA staff members saying that he was "[h]eading down now" when he was leaving for the event. *See* Exhibit 32.

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based on representations that they were considering out-of-state locations and requested an initial assessment of the net benefits test, an EDA employee indicated that he planned to run the test assuming that no jobs were at risk of leaving the state—and Mr. Lizura directed the employee to run a preliminary assessment as if the jobs were at risk.

Specifically, on August 31, 2016, Kevin Sheehan of Parker McCay sent an email to an EDA BDO requesting that preliminary award calculations be run for CSB, TMO, and NFI.[149] The BDO forwarded Mr. Sheehan's email to an EDA underwriting supervisor, Director of Bonds and Incentives John Rosenfeld, saying: "[These] are all the applicants that may go into the LPT [Liberty Property Trust] space at the Camden Waterfront. All three would like to know what their award could potentially be before focusing their efforts on an application for this space, especially since it's expensive."[150] When Mr. Rosenfeld ran the numbers for two of the three companies later that day, he explained the results internally to others at EDA as follows: "I would advise caution on these numbers but, based on the extremely limited information involved, it looks like these applicants COULD have a Net Benefit of approximately $36.8M and $43.3M respectively."[151]

A few days later, the assigned EDA BDO copied Mr. Lizura into her email chain with Mr. Rosenfeld, saying as follows: "Hi John, are these [calculations] including the new and retained job numbers that are listed below? Also Tim has requested to see the reports so he can review them as well, thanks!" Mr. Rosenfeld replied that he did not include any credit for income taxes related to jobs retained in New Jersey, because he had "assumed that this was a situation where the jobs would stay where they are in NJ without the award . . . ." Mr. Lizura flatly told Mr. Rosenfeld, "**The retained jobs are at risk. Can you run them as such**." (Emphasis added).[152]

Mr. Lizura's instruction to Mr. Rosenfeld to assume that the jobs were at risk, given the well-publicized commitment made by Mr. Norcross at the press conference that he attended, certainly invites skepticism. In an interview with the Task Force, Mr. Lizura said that he was merely instructing Mr. Rosenfeld to run the assessment using the numbers that Mr. Sheehan had provided and was not making a factual statement about whether the "retained jobs" were "at risk." He further indicated that, at that stage, he deferred to Mr. Sheehan about whether the jobs were "at risk" because Mr. Sheehan knew the tax-incentive programs well and understood their requirements. Mr. Lizura also stated that he viewed the statements in the September 2015 press

[149] Exhibit 33.
[150] Exhibit 33.
[151] Exhibit 33.
[152] Exhibit 33.

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release and press conference that CSB, TMO, and NFI had "committed" to the Camden waterfront development project only as a commitment to invest in the real estate project, and that he was not aware of whether CSB, TMO, or NFI had committed to relocate to Camden at any point before their applications were filed.[153] Given the statements a year earlier that the very companies applying had "committed" to Camden, the Task Force believes that these applications should have been scrutinized, particularly given the size of the awards at stake. Indeed, despite his instruction to Mr. Rosenfeld to defer to Mr. Sheehan's numbers about at-risk jobs, Mr. Lizura indicated during this interview with the Task Force that he instructed his team to pay particular attention to the applications because they involved companies related to Mr. Norcross. Mr. Lizura did not, however, identify any particular steps he asked the team to take to scrutinize the applications, and the Task Force has found no evidence of any. In any event, Mr. Rosenfeld, after re-running the test based on Mr. Lizura's instruction, said: "With the at risk jobs, they both get to about $88.8M in net benefit . . . ."[154] The final awards were granted based substantially on that calculation.

ii) The Applications

When CSB, TMO, and NFI submitted their Grow NJ applications on October 24, 2016, notwithstanding the prior public reports that the three companies had already "committed" to relocating to Camden, the companies all stated that they were considering a potential relocation to Philadelphia as an alternative.[155] Specifically, each company stated "Yes" in response to the application's question of whether jobs were at risk of being located outside of New Jersey and listed "Pennsylvania" as in competition with New Jersey for the jobs.[156] Each company stated, in virtually identical language, that the company's "business is expanding and requires additional space. If the credits are not awarded, the business will seek to relocate at a less expensive location outside of New Jersey."[157] Each company's application stated that the company had retained real

[153] Even if CSB's, TMO's, and NFI's only "commitment" was to invest in the real estate project, and not to relocate their offices there, as Mr. Lizura claims to have believed, it nonetheless is difficult to understand why a different understanding would not emerge once the companies filed their applications and indicated their intent to relocate there. The EDA had the authority to request documentation from CSB, TMO, and NFI that would have revealed the nature of the "commitment" the companies had made and when they made it, but the EDA failed to exercise such authority.
[154] Exhibit 33.
[155] Exhibits 27, 28, and 29.
[156] Exhibits 27, 28, and 29.
[157] Exhibits 27, 28, and 29.

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estate brokers "to identify Class A office space in Philadelphia."[158] Real estate proposal letters from real estate brokers for Philadelphia space for each company were attached to the applications.[159] However, TMO's and NFI's proposal letters for space in Philadelphia had already expired by the time the applications were filed. (CSB's proposal letter did not specify an expiration date.)

On November 18, 2016, the EDA underwriter assigned to the three companies' applications sent an email to Kevin Sheehan of Parker McCay, who represented all three companies, to ask whether the companies still had valid offers for space in Philadelphia, because the real estate proposal letters submitted with the companies' applications appeared to have expired.[160] The underwriter followed up ten days later, also asking Mr. Sheehan to clarify how many employees at the three companies were at risk of moving out of New Jersey.[161] Mr. Sheehan replied that "[a]ll employees are at risk in all 3 companies."[162] On November 30, 2016, Mr. Sheehan sent the EDA underwriter a new real estate proposal letter for CSB, dated December 1, 2016, outlining a proposal for space in Philadelphia.[163] The December 1, 2016 real estate proposal differed significantly from the prior real estate proposal that CSB had submitted with its application. The initial proposal offered approximately 150,000 sq. ft. of space on the third through seventh floors, and the eleventh and twelfth floors, of the building located at 1601 Market Street in Pennsylvania.[164] CSB's new letter offered the company "approximately 110,000" sq. ft. of space on the third through seventh floors and the thirteenth floor of the building. The letter stated that it would expire on December 31, 2016.[165]

Two months later, on March 1, 2017, Mr. Sheehan sent the EDA underwriter new real estate letters for NFI and TMO, outlining proposals for both companies for space at 1500 Spring Garden Street in Philadelphia.[166] Both real estate proposals differed from the initial, expired proposals that the companies submitted with their applications in respects, but the changes with respect to TMO's proposals were significant. TMO's initial real estate proposal, dated August 30, 2016, had offered

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[158] Exhibits 27, 28, and 29.
[159] Exhibits 34, 35, and 36.
[160] Exhibit 37.
[161] Exhibit 38.
[162] Exhibit 38.
[163] Exhibit 39.
[164] Exhibit 34.
[165] Exhibit 39.
[166] Exhibits 40 and 41.

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the company 103,491 sq. ft. of space on the second floor of 1500 Spring Garden Street.[167] The proposal further stated that, in the alternative, TMO was offered 103,710 sq. ft. of space on the first and seventh floors of the building.[168] TMO's second real estate proposal, dated February 28, 2017, offered the company 95,928 sq. ft. of space divided between the basement level, two separate suites on the first floor, a suite on the seventh floor, and another suite on the twelfth floor.[169] The proposal letter also stated that the space on the seventh floor—which comprised approximately a third of the total space offered to TMO—was "encumbered by a Right of First Offer in favor of [another company]."[170] Both NFI's and TMO's real estate proposal letters stated that they would expire on March 24, 2017.[171]

The differences between CSB's, NFI's, and TMO's first and second sets of real estate proposal letters for Philadelphia are summarized below:

Company	**CSB**		**NFI**		**TMO**	
Address	**1601 Market Street**		**1500 Spring Garden Street**		**1500 Spring Garden Street**	
Proposal	**First**[172]	**Second**[173]	**First**[174]	**Second**[175]	**First**[176]	**Second**[177]
Date	8/29/2016	12/1/2016	8/29/2016	2/28/2017	8/30/2016	2/28/2017
Total sq. ft.	153,345	~110,000	103,491	93,308	103,491 OR 103,710	95,928
Floors	3-7, 11-12	3-7, 13	2	2	2 OR 1,7	Basement, 1, 7, 12
Expiration	Unspcfd.	12/31/2016	9/9/2016	3/24/2017	9/9/2016	3/24/2017

[167] Exhibit 35.
[168] Exhibit 35.
[169] Exhibit 41.
[170] Exhibit 41.
[171] Exhibits 40 and 41.
[172] Exhibit 34.
[173] Exhibit 39.
[174] Exhibit 36.
[175] Exhibit 40.
[176] Exhibit 35.
[177] Exhibit 41.

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The EDA underwriter prepared Project Summary memoranda based on the information provided by the companies.[178] Each company's memorandum stated that the company was considering between relocation in the Camden Tower or an alternative location in Philadelphia, that their New Jersey jobs were "at risk of being located outside the State," and that Grow NJ tax credits would be a "material factor" in the company's decision whether to locate in Camden.[179] Under the "Conditions of Approval" section of each memorandum, it stated as Condition No. 1 that the company "has not . . . committed to remain in New Jersey."[180] Each memorandum concluded by recommending that EDA's Board "approve the proposed Grow New Jersey grant to encourage [the respective company] to locate in Camden."[181] The memoranda were provided to EDA's Board and, on March 24, 2017, the Board voted to approve CSB, TMO, and NFI for total tax incentive awards of almost $245 million—$86,239,720 for CSB, $79,378,750 for TMO, and $79,377,980 for NFI.

The Task Force has discovered evidence appearing to indicate that the three companies did not genuinely consider Philadelphia as an alternative location to Camden. In August 2016, only a few months before submitting their applications, and almost a year after the press conference during which their "commitment" to the Camden project was reported, Kevin Sheehan appears to have reached out to a real estate broker, Ken Zirk at CBRE, to solicit offers for real estate in Philadelphia. After the initial outreach, the companies collaborated to obtain proposals for Philadelphia real estate to submit to the EDA, and NFI led the efforts on behalf of all companies.

On August 26, 2016, NFI's Chief Financial Officer, Steven Grabell, sent an email to TMO's Chief Financial Officer, Joseph Purcell, and CSB's Chief Financial Officer, John Muscella, to explain that he had authorized the real estate broker "to proceed full speed ahead with getting a proposal for 1500 Spring Garden."[182] NFI's Mr. Grabell wrote that the building located at 1500 Spring Garden Street was large enough for both NFI and one other company to obtain proposals from, and further, the real estate broker had "identified an additional possibility for 95,000 square feet at 1601 Market" that the third company "could use."[183]

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[178] Exhibits 42, 43, and 44.
[179] Exhibits 42, 43, and 44.
[180] Exhibits 42, 43, and 44.
[181] Exhibits 42, 43, and 44.
[182] Exhibit 45.
[183] Exhibit 45. Meanwhile, Mr. Zirk reached out to another broker who represented the landlord for 1601 Market Street. Mr. Zirk's note, expressing interest in the building on behalf of CSB, was forwarded to the building's landlord, who was surprised by the request: "This does not make any sense, we get on Friday afternoon a [request for proposal] that is due on Monday? Where is this

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Several days later, on August 29, 2016, NFI's Mr. Grabell wrote to Mr. Zirk, the real estate broker, to ask when the companies would be getting term sheets for the 1500 Spring Garden and 1601 Market properties in Philadelphia.[184] Later that day, Mr. Zirk sent one proposal letter, for NFI alone, for 1500 Spring Garden Street.[185] That evening, Parker McCay's Mr. Sheehan wrote to the group of CFOs for the three companies and the broker, noting that the proposal was for NFI and asking, "Is there one for Michaels?"[186] In response, NFI's Mr. Grabell stated: "Enough space for Michael's in that building as well. **I think it would be a little suspicious to ask for a duplicate**. Any thoughts?" (Emphasis added).[187] TMO's Mr. Purcell responded and wrote that he had understood that all three of the companies were "going with the 1500 Spring Garden Property."[188] However, in view of the concern that it would be "a little suspicious" for multiple companies to claim the same alternative location in Philadelphia, TMO's Mr. Purcell wrote that he would be willing for TMO "to go with" a different location in another city entirely—Fort Washington, Pennsylvania, instead of Philadelphia—if one of the other two companies requested it.[189] NFI's Mr. Grabell replied that "1500 Spring Garden has space for 2 of us, but not 3. That is why we reached out to 1601 Market."[190] Mr. Grabell asked Mr. Zirk whether he would "feel comfortable getting a similar quote for Michael's for 1500 Spring Garden?"[191] Mr. Zirk responded that he would discuss with the landlord's broker "tomorrow first thing."[192] TMO ultimately obtained a

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tenant from? How would we not have known about a 100,000 SF prospects [sic]?" The broker responded with a lengthy explanation, noting, among other things, that CSB's "principal, George Norcross, is a major political figure in South Jersey & very well connected locally." The broker wrote to the landlord that CSB "had been attempting to [relocate to] Camden with Liberty Property Trust but the deal apparently got too expensive & they didn't get the tax breaks/incentives that they were seeking," so CSB had decided to move the jobs to Philadelphia instead. Exhibit 46. In fact, however, CSB had not yet applied for tax incentives in New Jersey at that point, let alone been rejected for them.

[184] Exhibit 47.
[185] Exhibit 47.
[186] Exhibit 48.
[187] Exhibit 48.
[188] Exhibit 48.
[189] Exhibit 48.
[190] Exhibit 48.
[191] Exhibit 48.
[192] Exhibit 48.

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proposal letter for 1500 Spring Garden, and CSB obtained a proposal letter for 1601 Market Street, which both companies submitted with their applications in October 2016.

Although the EDA did not have access to the companies' emails with the real estate broker, which the Task Force obtained, there were nonetheless clear red flags in CSB's, TMO's, and NFI's EDA application and in the public record that should have caused EDA personnel to question the three companies' statements that they were considering relocating out of the State. As discussed above, there were public statements, of which senior EDA leadership was aware, indicating that the three companies had already "committed" to relocate to Camden long before they claimed to be considering relocating to Philadelphia. Despite these public statements, EDA leadership appear to have instructed EDA staff that the companies' jobs were "at risk."

In addition, at the Task Force's public hearing on May 2, 2019, the current Managing Director of the EDA's the Underwriting department, David Lawyer (who did not work on these applications and was not responsible for the Grow NJ program at the time they were processed) testified that it was "unusual" for companies to submit expired proposal letters with their tax incentive applications, and the fact that the letters had expired when they were submitted "casts doubt on whether that site [was] available."[193] Mr. Lawyer also testified that the changes to the amount and the configuration of the space in TMO's alternative-site proposal, as well as the fact that a significant portion of the space was encumbered by a right of first offer, raised red flags about the sincerity of the company's consideration of the property.[194] Mr. Lawyer testified that, in his view, the issues with CSB's, TMO's, and NFI's real estate proposals raised serious questions, "because . . . there's a pattern."[195] Similarly, John Boyd, an expert in corporate site selection, testified that it is common for companies considering relocation to negotiate for extended offer periods to provide adequate time to assess the suitability of potential real estate.[196] That these companies did not do so but instead submitted expired real estate offers, therefore, was a red flag. Mr. Boyd further testified that in his experience, barring extraordinary circumstances like emergency relocation after a natural disaster, companies never want office space spread out over noncontiguous floors of a building of the sort TMO was purportedly considering, spread out across

[193] Hr'g Tr. (May 2, 2019) at 150:4-25, 162:12-16.
[194] Hr'g Tr. (May 2, 2019) at 163:12-17, 164:14-19.
[195] Hr'g Tr. (May 2, 2019) at 164:23-165:6.
[196] Hr'g Tr. (May 2, 2019) at 108:10-109:6.

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four separate floors, including the building's basement.[197] The EDA staff, however, took no action to further investigate based on these and other red flags.

In 2017, the EDA approved CSB, TMO, and NFI for almost $245 million in tax incentive awards collectively—approximately $86.2 million for CSB, $79.4 million for TMO, and $79.4 million for NFI. The Task Force requested the EDA recalculate the awards the three companies could have received if they had communicated to the EDA that they were not considering any potential relocation to Philadelphia instead of Camden—which, based on the evidence discussed above, appears to have likely been the truth. Based on recalculated net benefits analyses, the EDA concluded that CSB's award would have stayed the same ($86.2 million), that TMO would have qualified for only a $60.8 million award at most (rather than $79.4), and that NFI would have qualified for only a $27.2 million award at most (rather than $79.4). Therefore, the EDA's failure to investigate the red flags in these companies' applications could have resulted in over $70 million in improperly approved tax-incentive awards.

5. Lack of Proper Reporting Channels

The EDA does not have official reporting channels in place for the processing, review and recording of internal or external complaints about Program awardees or applicants and does not maintain a "hotline" or reporting line for outside parties to report potential misconduct related to the EDA's tax incentive or other programs. The absence of such reporting mechanisms makes it more likely that misconduct—whether on the part of EDA employees or companies—will be missed.

Several EDA employees we interviewed suggested that external complaints or tips should be elevated to an individual in Human Resources or the Deputy Attorney General, but there was no official reporting line or process for ensuring that all complaints and tips were carefully considered and escalated to the appropriate individuals. Nor was there an official record of such complaints or tips maintained within the EDA. Two BDOs we interviewed recalled outreach from FBI agents regarding a potentially fraudulent application. Those BDOs recalled that the information was generally "disseminated" amongst the directors and Deputy Attorney Generals, but there was no formal system for tracking flagged companies. In another instance, a local contact advised a BDO Program Manager that a Grow NJ awardee had recently fired 80 employees—or 30% of its workforce. The Program Manager who received this notice recalled that he referred the information to the Director of Portfolio Management and Compliance but was not involved in any further action. The Managing Director of Business Development indicated that there was no policy regarding how to treat this type of information but believed the information would have been "socialized" within

[197] Hr'g Tr. (May 2, 2019) at 109:11-110:8.

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the EDA and referred to the Portfolio Management and Compliance group if it involved a tax incentive grant recipient. Although we believe that, in the latter example, the information ultimately reached the appropriate individuals, an express policy regarding the steps required to process and record this type of information would substantially improve the EDA complaint processing to ensure that information from outside parties regarding potential misconduct is not missed.

VI. THE ACCELERATED RECERTIFICATION PROGRAM (THE "ARP")

A. Introduction

As discussed above, in order to fully investigate the administration of the Programs, the Task Force undertook to examine the EDA's processing of awards for companies that applied for and received tax-incentive credits under the Programs. Given the findings of the Comptroller's audit, moreover, the Task Force has sought to determine whether each company in scope was compliant with applicable statutory, regulatory, and administrative requirements when the EDA approved its application and when it received tax credits under Grow NJ or ERG. To facilitate an investigation and review process that promotes resource efficiency, collaboration with companies, and expedient processing for compliant companies, the Task Force established the ARP. During its initial outreach and communications with companies in scope, the Task Force received overwhelming interest in the ARP. As a result, the Task Force announced the ARP during its first public hearing on March 28, 2019.

Without an expedited process of the sort provided by ARP, the Task Force would have conducted a broader investigation into each company's award. This could have included expansive document requests, interviews of relevant company personnel, and extensive document and data review. As an alternative, the ARP provides companies a streamlined process to proactively establish that they are in compliance with the Programs' requirements. If a company declined to participate in the ARP, or if the Task Force deemed it ineligible, the company's award is subject to the broader investigative process necessary to carry out the Task Force's mission.

B. ARP Participant Companies

The Task Force deems companies eligible for the ARP if the company (1) completes and submits an initial affidavit (the "ARP Initial Affidavit") and (2) the Task Force has not received or identified information suggesting misconduct, fraud, or other non-compliance with applicable requirements with respect to the company's application for, approval for, or issuance of tax incentives.

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The Task Force requires each company's CEO, or equivalent personnel, to execute the ARP Initial Affidavit, which provides additional company information to the Task Force. The ARP Initial Affidavit requires companies to describe their efforts to comply with the Task Force's document preservation directive and to identify document custodians and third parties that may possess relevant documents. Companies must also agree to voluntarily and promptly produce relevant documents to the Task Force. As of the date of this Report, 53 companies have pursued participation in the ARP. Despite the overwhelming participation in ARP, we note that approximately 8 otherwise eligible companies expressly declined to participate in the ARP. We appreciate that each company operates under a different set of resources, frameworks, and stakeholders. Therefore, we emphasize that at this time, we cannot— and have not—drawn any conclusions about companies that did not elect to participate in the ARP.

There have been several instances where companies sought inclusion into the ARP, but their eligibility is still under consideration by the Task Force for myriad reasons. In some instances, the Task Force has become aware of concerning information regarding the company's application or award. For example, for a number of companies, the Task Force has learned through independent evidence and information that the company's assertions regarding its intention to relocate are questionable. In these cases, proposed jobs may not have actually been at risk of leaving or locating outside of New Jersey, contrary to the companies' representations to the EDA. The Task Force reserved the option to investigate further before allowing the companies in question to participate in the ARP.

For other companies, the Task Force has become aware of information suggesting that these companies committed to locate in New Jersey before they submitted their EDA application. In other circumstances, the Task Force is aware of information suggesting misrepresentations or misconduct in connection with the jobs requirements of the award. In these cases, the Task Force reserved the ability to further investigate and review written responses and assertions made to the EDA to determine whether a company's application contained misrepresentations.

Several companies that exhibited threshold issues of the sort described above submitted the ARP Initial Affidavit. In the interest of transparency and continued cooperation, the Task Force contacted these companies to discuss obstacles to their ability to participate in the ARP. In many instances, companies were not deterred by this message and have continued to work with the Task Force to provide requested documents and information. The Task Force is reviewing this information before confirming the companies' categorization going forward.

Finally, there is a tranche of companies that the Task Force disqualified or deemed ineligible for ARP participation. The Task Force has disqualified companies where the Task Force has

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identified a reasonable basis to believe that further investigation may reveal instances of misconduct, fraud, violations of applicable requirements, or other issues suggesting the company's lack of good faith. Separately, the Task Force may also disqualify companies where they fail to comply with the Task Force's requests or the ARP requirements.

C. ARP Process

In order to establish a process that would enable it to determine whether a company was in compliance with Program requirements, the Task Force carefully reviewed related statutes, EDA regulations and requirements, and met with key EDA personnel to determine exactly what it means "to be compliant." Thereafter, the Task Force created a framework for information requests, document collection, and interviews that would provide adequate information for the Task Force to review and make a determination of compliance with Program requirements. The Task Force has taken care to continue an open dialogue with each participating company to better understand the company's framework, business, and key stakeholders. Accordingly, while the Task Force has established a process for the ARP, it also is working collaboratively with each company, with an understanding that each company's documentation, application, and purported needs for the tax incentives vary significantly.

From a process perspective, once companies submit the ARP Initial Affidavit and are deemed eligible by the Task Force, the Task Force requests certain written responses, with supporting documents where necessary ("Verifying Documents"), related to each company's application. The Task Force's ARP for Grow NJ requires the company to submit additional documentation related to the company's good faith business plan to relocate or locate in New Jersey, its plan for new or retained full-time jobs, and its expenditures comprising its capital investment. The Task Force's ARP for ERG requires submission of documentation related to the project's financing gap and development and the project developer's good standing. While the ARP requires documentation beyond what the EDA requested, these requests are narrowly tailored to identify representative materials that will allow the Task Force to examine the company's application and award.[198] As part of the review process, the Task Force engages in open communication with the company for clarifications, context, and additional information.

A company must provide a final affidavit from its CEO, or equivalent personnel, ("Verification Affidavit") and the requested Verifying Documents. To assist companies, the Task Force provides a template Verification Affidavit that the company tailors to its specific

[198] For example, to assess the company's good faith intentions to locate to New Jersey, the Task Force requests contemporaneous business records or communications discussing the relocation plan and the suitability of the proposed alternative site.

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circumstances. Thereafter, the company submits a draft affidavit. The Task Force reviews the information supplied to determine whether the company applied for its tax-incentive in good faith and with accurate information; met the application's requirements; and complied with the program requirements for each and every subsequent year it participated in the Programs. If the Task Force can make these determinations based on the information the company provides, the Task Force will accept a final Verification Affidavit. Upon successful completion of ARP, the Task Force will send a verifying closing letter ("Closing Letter"), confirming the company's successful re-certification.[199]

D. Initial Findings

The ARP process has provided the Task Force with opportunities to identify deficiencies with the Programs' designs and with the EDA processes to implement the Programs. By engaging with companies in the ARP and by collecting, reviewing, and analyzing information and data from the company's internal deliberations, the Task Force has been able to evaluate the requirements and EDA regulations from the company perspective.

Based on this examination, the Task Force has determined that both the existing legislation and the EDA requirements are ambiguous in certain respects that has impacted the EDA's ability to ensure consistency in how these requirements are applied across project applicants.[200] Some examples include:

- **EDA verification of cost benefit analysis**: An ARP company explained that after it submitted its application materials and cost benefit analysis, the EDA did not request any support for the line-item estimates in the company's cost benefit analysis, which showed that New Jersey was more expensive than the proposed alternate location. The company agreed that at the time of its application, the EDA had no verification that the line items in

[199] However, the Task Force's Closing Letter has no binding effect on any other agency or office of the State of New Jersey. Moreover, should the Task Force become aware of credible reason to believe there was misconduct, the Task Force reserves the right to make such information known to other law enforcement agencies.
[200] We understand that the EDA has, in the last year or so, begun to implement solutions to these deficiencies through its own processes and approval requirements.

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its proposed estimate were accurate and not exaggerated, estimated, or manipulated in any way.[201]

- **Clear legislative guidance and definitions for award bonuses categories**: After another ARP company submitted its initial application to the EDA, the EDA questioned whether it qualified as a technology business for the purposes of an award bonus. Under the Grow NJ statute as amended by EOA 2013, "technology" is a "targeted industry" such that qualifying "technology" companies are eligible for an additional grant of up to $500 annually per job.[202] However, neither the Grow NJ statute, nor EDA's implementing regulations, nor any policy documents maintained by EDA define what constitutes a "technology" company. Based on the Task Force's review, the Task Force found that EDA employees struggled over the appropriate characterization for the company.

- **EDA requirements related to applicants' submissions regarding potential alternative locations**: The EDA has not consistently required applicants to submit the same materials regarding the viability of the proposed alternative site.

VII. RECAPTURE

The Task Force seeks to achieve not only recommendations for the tax-incentive programs prospectively but to recommend recapture of improperly credited taxpayer dollars. These recommendations and efforts for recapture have involved cooperation and coordination with several areas of New Jersey State government, including the EDA, the Department of Taxation, and the New Jersey Attorney General's Office.

A. Statutory Recapture Process

The current Grow NJ legislation specifically sets forth language identifying the EDA's authority to recapture tax-incentive awards under certain circumstances.

Under the Grow NJ Act, applicants must enter into an incentive agreement with the EDA before the awardees receives any tax credits. One of the required provisions of this incentive agreement is that the applicant commits to remaining in its New Jersey facility for a minimum period of time. Typically, this period would include a ten-year term, during which the company

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[201] The Task Force closely examined supporting information provided by the company, including the actual costs accrued after the company successfully received its grant and moved to New Jersey, and found no indication that the proposed analysis was made in bad faith.
[202] *See* N.J. Stat. §§ 34:1B-246(c)(8), 34:1B-243 ("targeted industry" definition).

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receives its award amount as annual credits, plus an additional five years after all annual credits are issued.[203] The statute further requires that if the company fails to honor this commitment, the EDA may recapture all or part of the tax credits awarded, although EDA retains the discretion to recognize the period of time that the company complied with the award requirements.[204]

B. Task Force Recommendations for Recapture

The Task Force has instituted its own processes to recommend recapture of tax-incentive awards and to assist the EDA with its recapture of tax-incentive awards.

When companies have indicated a willingness to cooperate and disclose any potential non-compliance, the Task Force has offered, and will continue to recommend and connect the company with the State Treasury for settlement. The Task Force considers such settlement recommendations based on the company's specific factual circumstances. However, for the Task Force to consider a settlement recommendation, the company must be willing to agree to several terms. First, the company must voluntarily terminate its tax-incentive award, including taking all steps that the EDA requires for the company to terminate its award. Second, the company must repay the value of the tax-incentive benefit already claimed. Third, if it becomes aware of credible evidence of criminal misconduct relating to the tax-incentive programs, the Task Force reserves its right to make such information known to other enforcement authorities. Finally, any settlement agreement with a State agency does not bind any other agency or office of the State of New Jersey. Companies that settle do not admit to any liability.

Separate from potential settlements, the Task Force has also referred, and will continue to refer, certain companies and awards to the EDA to consider whether additional credits should issue or whether previously received credits should be recaptured. The Task Force may also refer companies to appropriate law enforcement authorities for further investigation. Should law enforcement authorities pursue a criminal investigation and charges, this could generate sufficient evidence that a company's award was improperly awarded.

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[203] *See* N.J. Stat. Ann. § 34:1B-243 (defining the "eligibility period" as "the period in which a business may claim a tax credit," beginning with the first year the company certifies for a credit but that the term will be no longer than 10 years); *Id.* (defining "commitment period" as "1.5 times the eligibility period").
[204] *See* N.J. Stat. Ann. § 34:1B-245(d); *see also* N.J. Admin. Code § 19:31–18.10(b)(3).

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Currently, the Task Force has referred a number of applicants for suspension /or termination of their tax-incentive awards or obtained voluntary termination. In all, the aggregate amount of the grants at issue exceeds $500 million.

VIII. RECOMMENDATIONS

Executive Order No. 52 called for the Task Force to offer advice concerning the future of New Jersey's tax-incentive programs. Although the Task Force's work remains ongoing, its investigation and analysis to date have revealed certain deficiencies in the design, implementation, and oversight of the Programs now in place. Based on its findings, the Task Force offers the following recommendations with respect to the State's current and future tax-incentive programs, which will be supplemented as the Task Force's work continues.

Recommendation 1: The Task Force's investigation to date has found that special interests have had a significant hand in molding the current Programs' legislation and implementing regulations in their favor. As a result, in certain respects, the Programs have not been "neutral" in their design but have instead been structured to favor the business interests of certain parties, and in some cases to disfavor other parties. Future tax-incentive legislation should be designed to ensure that legitimate public policy goals are applied neutrally, without favoring specific business interests.

Recommendation 2: Future tax-incentive legislation should be transparent with respect to the benefits or costs of the programs. Under the current Grow NJ program, all tax incentive awards are statutorily required to "yield a net positive benefit to the State."[205] Based on this statutory provision, the State should profit from the program. However, this requirement is undermined by provisions of the statute allowing the benefits calculation to include the value of certain taxes that the State will never actually collect. By allowing such so-called "phantom taxes" to be included in the benefits calculation, the "net positive benefit to the State" that is supposed to be required by the law may be rendered illusory, obfuscating the potential costs of the tax incentives and contributing to public confusion.

Recommendation 3: To further promote transparency and public understanding, the goals of future tax-incentive legislation should be clearly defined, and the program should be structured to effectuate those explicit goals—not other unspecified aims. Currently, the Grow NJ Act expressly states that a "purpose of the [Grow NJ] program is . . . to preserve jobs that currently exist

[205] N.J. Stat. § 34:1B-244(a)(3).

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in New Jersey but which are in danger of being relocated outside of the State."[206] However, as discussed in Section IV(A)(1)(e) of this First Report, certain provisions of the Grow NJ Act are sufficiently vague that companies may be able to receive tax credits for relocating existing jobs in New Jersey to Camden or Atlantic City, even if the jobs were never "in danger of being relocated outside the State." Tax incentives in these circumstances clearly do not advance the statutory aim of preserving jobs in the State. If it was also an intended purpose of Grow NJ to incentivize the relocation of existing jobs from other parts of New Jersey to Camden or Atlantic City, it would have aided public understanding to set out this purpose explicitly in the statute, along with the other intended purposes.

Recommendation 4: Relatedly, the Task Force's examination has found that the current statutory text for the Programs contains ambiguities in certain respects. This is illustrated by the issues relating to the "material factor" test that applies to projects in Camden and Atlantic City. It also applies in other areas: for example, as discussed in Section VI(D) of this First Report, there was one instance in which it was unclear whether a company qualified under certain provisions of Grow NJ for "technology" companies—a statutory term that is not defined in the law. Ambiguities in statutory text are inevitable. However, when such ambiguities arise in the administration of a statute, the responsible agency should both determine the resolution of the issue and further publicize its decision so that the rules are clear and known and are applied consistently. When the EDA addresses statutory ambiguities such as this one, it should embody its decisions in published rules (whether in the form of regulations, formal policies, or other guidance documents) that are available to the public.

Recommendation 5: Future legislation should be designed to ensure that the EDA can better control whether companies that meet the employment or other requirements for only a small portion of their commitment period are eligible to receive their full annual award. It should also include provisions ensuring that companies cannot receive a full year's award without meeting the requirements for a full year, and without providing a full year's worth of data to prove their compliance.

Recommendation 6: The EDA should issue comprehensive written policies and procedures to guide its employees in administering the Programs and should implement formal internal training mechanisms with respect to all aspects of the current Programs and any future tax-incentive programs. Although the Task Force fully appreciates that the Programs are complex and often amended, the Task Force's investigation to date has nonetheless found undeniable

[206] N.J. Stat. § 34:1B-244(a).

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deficiencies in certain EDA employees' understandings of the applicable requirements in various respects. The EDA's shortfall in the issuance of regulations and policy and guidance documents likely contributed to these deficiencies, as it limited the resources available to these employees.

Recommendation 7: As described above, the Task Force, third parties, and the media have all discovered significant and adverse information about program applicants, much of which required very little effort. Thus, it seems quite clear that—whatever the EDA's underwriters are doing in the way of independent research on applicants—the work has been deficient. Moreover, the notion of awarding applicants millions, tens of millions, or even hundreds of millions of dollars in tax incentives without a rigorous background check on the company, its officers, and affiliates defies common sense. Thus, we strongly urge that any new legislation include a provision directing the EDA to use a qualified professional services firm to conduct rigorous background checks.

Recommendation 8: With respect to the specific issue of assessing an applicant's representation that the applicant is considering locating outside of New Jersey, the Task Force's investigation to date has found clear deficiencies in the EDA's assessments. There have been instances in which Grow NJ applicants have made representations concerning the possibility of an out-of-state location that should have raised serious red flags concerning the applicant's sincerity, and yet the EDA failed to take any action to investigate the issue. As discussed above, the Grow NJ Act explicitly states that a "purpose of the [Grow NJ] program is . . . to preserve jobs that currently exist in New Jersey but which are in danger of being relocated outside of the State."[207] If tax incentives are awarded to incentivize a company to stay in the State when the company never actually intended to leave, then public funds are essentially wasted. The Task Force has found, however, that the EDA's administration of the Grow NJ program has in many ways not sufficiently appreciated this principle. The EDA should improve its performance with respect to this aspect of the program, including by providing clear guidance and training to employees on how to conduct such assessments and instructing them on the importance of this issue. The EDA should provide its employees with a clear framework to apply in assessing applicant representations concerning alternative locations.

Recommendation 9: Grow NJ applicants are required to include certifications, signed by the company's CEO (or an equivalent officer), representing that the CEO "has reviewed the information submitted to the [EDA in connection with the application] and that the representations contained therein are accurate."[208] However, issues may arise when a company modifies its

[207] N.J. Stat. § 34:1B-244(a).
[208] N.J. Stat. § 34:1B-244(d).

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application at some point after it is submitted, but does not submit a new CEO certification attesting to the truthfulness of the new information. The EDA should have a formal policy or regulation requiring the submission of a new CEO certification whenever an application is materially changed after its submission.

IX. NEXT STEPS

As we noted at the outset, the Task Force is continuing its investigation. It will continue to review documents it has received in response to requests to the EDA and third parties, and to interview witnesses to gain a deeper understanding of any flaws in the design, implementation, or administration of the programs. Among other things, the Task Force intends to:

- Hold further public hearings in which the public will have the opportunity to share its views and perspectives;
- Focus its investigation on the design, implementation, and administration of the ERG Program;
- Continue its investigation of the EDA's oversight over Grow NJ and ERG applications;
- Consider additional ways to make the application and compliance verification process more robust;
- Continue the re-certification process for companies participating in the ARP; and
- Continue its efforts to recapture tax-incentive awards where warranted and, as necessary, make additional referrals to the appropriate enforcement authorities.

In addition, the Task Force will examine the impacts of certain aspects of the Programs that may differ from other states' programs, from prior New Jersey tax-incentive programs, or from best practices described by policy experts. In that regard, the Task Force intends to further examine the policy recommendations made by two of the experts that testified during the first day of the public hearings, Josh Goodman, Senior Officer for State Fiscal Health, at The Pew Charitable Trust, and Jon Whiten, Deputy Director of State Communications at the Center on Budget and Policy Priorities. In particular, the Task Force intends to explore:

- Whether the State should consider targeting its tax incentives to businesses that will increase the State's economic growth by serving national and international markets, rather than local markets;
- Whether the State should shorten the timeframes for receiving tax incentives, in an effort to spend less on incentives while achieving the same impact, and to enable it to better predict the costs and benefits of awarding incentives to businesses;

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- Whether the Programs' approach to awarding tax incentives in distressed areas sufficiently benefits the residents of those areas and what steps, if any, could be taken to fine tune New Jersey's approach to using tax incentives to help economically distressed areas to ensure that residents of distressed areas actually benefit from tax incentives targeted at improving the economy in distressed areas;
- Relatedly, whether to revise the method for calculating the net benefit to the State for companies moving to distressed areas;
- Whether capping the tax incentives by setting annual cost limits would improve the Programs, and what other options for increasing fiscal protections might be undertaken;
- Whether New Jersey should regularly conduct independent evaluations of the effectiveness of the tax incentives programs and to establish systems mandating greater oversight and annual evaluations of the Programs; and
- Whether the State should limit or prohibit the transfer of tax credits awarded under the Programs.

The Task Force will also seek the input of additional policy experts to the extent they have views on these issues.

EXHIBIT 27

Internal reports contradict regulators' public findings over San Onofre spent fuel

sandiegouniontribune.com/news/watchdog/story/2019-09-22/internal-reports-contradict-nrc-public-findings-

September 22, 2019

When a 50-ton cask filled with radioactive waste got wedged 18 feet above the bottom of its concrete silo back in August 2018, work crews at the San Onofre nuclear plant were able to lower the container to its intended resting place after nearly an hour.

Majority plant owner Southern California Edison halted plans to transfer millions more pounds of spent nuclear fuel from wet to dry storage while federal regulators investigated what happened and made sure the process was safe.

Federal inspectors found many of the waste-filled canisters had been scraped and scratched as they were lowered into the interim storage facility. Even so, the U.S. Nuclear Regulatory Commission allowed the waste transfer program to resume in July.

Documents recently obtained by The San Diego Union-Tribune show that an agency field inspector reviewing the August 2018 incident issued internal reports noting that the canisters were designed — and certified — to be lowered into the storage vault without any scratches.

NRC inspector Lee Brookhart wrote that the required final safety analysis report and the certificate of compliance and technical specifications call for no scratches on the caskets.

"The original FSAR (final safety analysis report) statement for no scratches mirrored the CoC/TS (Certificate of Compliance and Technical Specifications) design basis that no scratches would ensure the code adherence," Brookhart wrote in March.

NRC officials did not respond Friday to questions about those internal reports. An Edison spokesman said the utility is fully compliant with federal regulations and the reloading work has been proceeding safely.

Edison spokesman John Dobken said Friday the utility is following federal rules.

"There's another process available for licensees: 72.48," Dobken said, referring to the U.S. Code of Federal Regulations section that allows a licensee to make changes in procedures or design of the casks used to store spent nuclear fuel. "That's what we used to account for the incidental contact going forward," he said.

The regulation is here:
https://www.nrc.gov/reading-rm/doc-collections/cfr/part072/

Dobken said that the company visually inspected eight of the canisters and found no evidence that the scratches would prevent the containers from safely storing spent nuclear fuel.

The canisters Edison is relying on to store spent fuel are licensed to be use for two decades.

The current plan calls foreventuallymoving the canisters away from San Diego once a more permanentstoragesite is agreed to. But critics of the process worry that the scratches outside so many of the canisters could make them difficult to move.

“If you have scrapes, scratches and gouges, that is a trigger for cracks to start,” said Donna Gilmore, an activist in San Clemente who runs a community group called San Onofre Safety.

Brookhart, the NRC inspector, concluded in March that a formal design change would be required to allow the canisters to remain in service.

Instead of pursuing changes to the approved canister design process, Edison relied on a different safety standard to argue that its existing method are compliant and safe.

Brookhart did not agree that a different methodology would satisfy the requirements of the canisters’ previous certification.

“I just don’t see how that meets CoC,” the NRC inspector said. “... Essentially the change (in methodology) is adding an alternative to the code to not have to do inspections and repair these new defects.”

Brookhart’s supervisors at the regulatory agency did not embrace the inspector’s conclusions. On July 15, the commission allowed Edison to restart the fuel transfer program and move forward with decommissioning the plant.

“The licensee implemented an oversight program to ensure that contractors conducted decommissioning work activities in accordance with procedural requirements as well as license expectations,” the NRC said in a report to an Edison vice president, Doug Bauder.

“The licensee implemented operational, radiological and housekeeping programs to ensure safe storage of spent fuel,” senior regulators concluded.

San Diego attorney Michael Aguirre, who has filed several lawsuits aimed at stopping the burial of 3.6 million pounds of nuclear waste in the beach north of Oceanside, said the internal reports show that the NRC disregarded its own inspector in favor of Southern California Edison.

“These decisions should be based on professional inspectors and not on lobbyists and political players at the NRC,” Aguirre said. “It underscores why the downloading has to stop because it is interfering with the ability to transfer the canisters to a safer location.”

Questions over the interim storage of nuclear waste at San Onofre have persisted since the plant was closed in 2012. At least 8 million people live within 50 miles of the plant and many of them are scared that the site could present a public health threat.

Under U.S. law, the U.S. government is responsible for the permanent storage of the San Onofre waste — as well as all of the other spent nuclear fuel in North America. But for decades, federal officials have been unable to agree on a permanent storage facility.

The San Onofre decommissioning plan calls for moving the waste into about 80 heavy concrete canisters by the end of next year so Edison can dismantle the rest of the shuttered plant and return the property to its owner, the U.S. Navy.

Two years ago, Edison agreed to make “commercially reasonable” efforts to relocate the San Onofre waste to settle a lawsuit Aguirre filed in 2015.

EXHIBIT 28

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Home > Radioactive Waste> Spent Fuel Storage > FAQ

Spent Fuel Storage in Pools and Dry Casks Key Points and Questions & Answers

On this page:

- Questions and Answers – General
  - What is spent nuclear fuel?
  - Why does spent fuel need to be cooled?
  - Why not require real time radiation monitoring or EPA RadNet monitors around an independent spent fuel storage installation (ISFSI)?
  - How are licensees required to fund dry storage facilities?
  - What is high burnup fuel?
  - Could high burnup fuel degrade in storage?
  - What were the inspection results of the canisters located at the Diablo Canyon ISFSI?

- Questions and Answers – Spent Fuel Pool Safety
  - What do you look at when you license a fuel storage facility? How do I know it can withstand a natural disaster?
  - How do you know the fuel pools are safe? Does the NRC inspect these facilities, or just the reactor itself?
  - What would happen to a spent fuel pool during an earthquake? How can I be sure the pool wouldn't be damaged?
  - Can spent fuel pools leak?
  - How would you know about a leak in such a large pool of water?
  - How can operators get water back in the pool if there is a leak or a failure?
  - Do U.S. nuclear power plants store their fuel above grade? Why is this considered safe?
  - How are spent fuel pools kept cool? What happens if the cooling system fails?
  - What keeps spent fuel from re-starting a nuclear chain reaction in the pool?

- Questions and Answers – Dry Cask Safety
  - What is dry cask storage?
  - What is an "ISFSI"?
  - What kind of license is required for an ISFSI?
  - How does the NRC determine that a dry storage system is safe?
  - What are the requirements for the selection and use of a dry storage system at an NRC licensed commercial power reactor site?
  - What Risk Assessments have been conducted for dry storage systems?
  - How do the NRC requirements ensure that dry storage systems do not release radioactive material and expose workers and members of the public to radiation?
  - How are dry storage systems inspected?
  - What can remote visual testing be used to detect?

- How does the NRC conduct oversight of Licensees?
- How does the NRC verify that canisters are properly loaded in accordance with their NRC Certificate of Compliance?
- How can the fuel or internal components be inspected on canisters with welded lids?
- How would welded stainless steel canisters be repaired if necessary?

- Questions and Answers – Waste Confidence & Future Plans
  - How long is spent fuel allowed to be stored in a pool or cask?
  - What is the plan for storage of spent nuclear fuel going forward? Will on-site storage continue to be the way for the foreseeable future?
  - These casks are already pretty old and could be storing spent fuel for decades to come. How can you protect them from deteriorating over time, especially from effects that have been seen at other nuclear installations such as alkali-silica reaction or chloride-induced stress corrosion cracking?
  - How are the long-term impacts of onsite storage of spent fuel analyzed, and what measures are taken to minimize potential impacts on public health and safety?
  - After a plant is decommissioned there will be no infrastructure to handle the repackaging of spent fuel if the storage systems need replacement. Is there a plan for this contingency, and what are the safety implications of reopening the storage cask?

- Questions and Answers – Security
  - What about security? How do you know terrorists won't use all of this waste against us?
  - How are dry storage systems canisters at ISFSIs protected against terrorism such as the September 11, 2001 terrorist attacks using hijacked airplanes?

- Questions and Answers – Emergency Planning
  - Are potential seismic effects considered in the assessment of canisters for continued operation? –EP
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TOP

Questions and Answers – General

What is spent nuclear fuel?

"Spent nuclear fuel" refers to fuel elements that have been used at commercial nuclear reactors, but that are no longer capable of economically sustaining a nuclear reaction. Periodically, about one-third of the nuclear fuel in an operating reactor needs to be unloaded and replaced with fresh fuel.

TOP

Why does spent fuel need to be cooled?

Spent fuel continues to generate heat because of radioactive decay of the elements inside the fuel. After the fission reaction is stopped and the reactor is shut down, the products left over from the fuel's time in

the reactor are still radioactive and emit heat as they decay into more stable elements. Although the heat production drops rapidly at first, heat is still generated many years after shutdown. Therefore, the NRC sets requirements on the handling and storage of this fuel to ensure protection of the public and the environment.

TOP

Why not require real time radiation monitoring or EPA RadNet monitors around an independent spent fuel storage installation (ISFSI)?

The regulations require that an independent spent fuel storage installation (ISFSI) must have the capability for continuous monitoring of the storage confinement system in a manner such that the licensee will be able to determine when corrective action needs to be taken to maintain safe storage conditions. For dry spent fuel storage, periodic monitoring is sufficient, provided that periodic monitoring is consistent with the dry spent fuel storage cask design requirements. The monitoring period must be based upon the spent fuel storage cask design requirements. Therefore, the NRC determined that adequate radiological monitoring capabilities already exist at licensed facilities.

All ISFSIs have multiple radiation monitors to ensure they meet NRC dose limits. This is typically accomplished using multiple thermoluminescent dosimeters (TLDs) on the ISFSI fence. These TLDs are regularly monitored. The results of the monitoring program are one of many items, procedures, and operations reviewed by NRC staff. NRC staff inspection reports are made publicly available, unless they contain classified, safeguards, or sensitive information.

TOP

How are licensees required to fund dry storage facilities?

Licensees are required to set aside funding for the management of spent fuel after a plant permanently shuts down until the fuel is transferred to the Department of Energy (DOE) for final disposal. Although the annual costs for continued storage are manageable, cumulative costs will continue to increase.

Under 10 CFR 50.54(bb), licensees are required to obtain approval from the Commission concerning the program by which they intend to manage the irradiated fuel. This includes all plans to provide funding for the management of the fuel at the reactor until title and possession of the fuel is transferred to DOE for permanent disposal in a repository.

The NRC has requirements in 10 CFR 72.22(e) for license applicants to show they have the necessary funds available to cover estimated construction costs, estimated operating costs over the license term, and estimated decommissioning costs. NRC staff review this at the time of initial license application and at the time of license renewal to determine if the applicant has demonstrated reasonable assurance that funding will remain available for the duration of the facility's license.

TOP

What is high burnup fuel?

Burnup is a measure of how much energy is obtained from the fission of uranium, or fuel, in the reactor. Burnup is measured in gigawatt-days per metric ton of uranium (GWd/MTU). Spent fuel is considered high burnup at a value greater than 45 GWd/MTU.

For more information, see the Backgrounder on High Burnup Spent Fuel

TOP

Could high burnup fuel degrade in storage?

The NRC has conducted testing through the National Laboratories and found that high burnup fuel is robust against storage and transportation loads. The inert environment inside the casks maintained during storage provides assurance that high burn up fuel will maintain its integrity under normal and accident conditions. Ongoing long-term demonstrations of loaded high burn-up fuel with other material types are being conducted by the U.S. Department of Energy and Electrical Power Research Institute (EPRI), and are expected to confirm the previous laboratory testing.

For more information, see the following:

- NUREG-2224 – Dry Storage and Transportation of High Burnup Spent Nuclear Fuel
- High Burnup Dry Storage Cask Research and Development Project: Final Test Plan

TOP

What were the inspection results of the canisters located at the Diablo Canyon ISFSI?

The assessment of the conditions on the Diablo Canyon canisters are described in the Electrical Power Research Institute report EPRI-3002002822 and the Sandia National Laboratories report SAND2014-16383. The canister surfaces appeared in good condition with no signs of degradation or corrosion. Researchers noted a mixture of dust and pollen, along with sodium chloride (NaCl) and some magnesium sulfate (MgSO4) on the surface of the canisters. Sodium chloride can cause corrosion in some metals, but it is unlikely given the environment the casks are in.. Using temperature and humidity data from the Vandenberg weather station, the time required for chloride induced stress corrosion cracking (CISCC) to corrode through the cask would be greater than 1,800 years. NRC staff will continue to monitor the situation to ensure such corrosion does not become a problem. Another CISCC-inducing compound, magnesium chloride (MgCl2), was not present on the Diablo Canyon canisters. The conclusion section of the SANDIA report explains limitations for the sample collection and analysis.

Additional information is available in the following EPRI and Sandia reports:

- EPRI-3002002822
- SAND2014-16383
- Susceptibility Assessment Criteria for Chloride-Induced Stress Corrosion Cracking (CISCC) of Welded Stainless Steel Canisters for Dry Cask Storage Systems

TOP

Questions and Answers – Spent Fuel Pool Safety

What do you look at when you license a fuel storage facility? How do I know it can withstand a natural disaster?

The NRC's requirements for both wet and dry storage can be found in Title 10 of the Code of Federal Regulations (10 CFR), including the general design criteria in Appendix A to Part 50 and the spent-fuel

storage requirements in Part 72. The staff uses these rules to determine that the fuel will remain safe under anticipated operating and accident conditions. There are requirements on topics such as radiation shielding, heat removal, and criticality. In addition, the staff reviews fuel storage designs for protection against:

- natural phenomena, such as seismic events, tornados, and flooding
- dynamic effects, such as flying debris or drops from fuel handling equipment and drops of fuel storage and handling equipment
- hazards to the storage site from nearby activities

TOP

How do you know the fuel pools are safe? Does the NRC inspect these facilities, or just the reactor itself?

NRC inspectors are responsible for verifying that spent fuel pools and related operations are consistent with a plant's license. For example, our staff inspects spent fuel pool operations during each refueling outage. We also performed specialized inspections to verify that new spent fuel cooling capabilities and operating practices were being implemented properly.

TOP

What would happen to a spent fuel pool during an earthquake? How can I be sure the pool wouldn't be damaged?

All spent fuel pools are designed to seismic standards consistent with other important safety-related structures on the site. The pool and its supporting systems are located within structures that protect against natural phenomena and flying debris. The pools' thick walls and floors provide structural integrity and further protection of the fuel from natural phenomena and debris. In addition, the deep water above the stored fuel (typically more than 20 feet above the top of the spent fuel rods) would absorb the energy of debris that could fall into the pool. Finally, the racks that support the fuel are designed to keep the fuel in its designed configuration after a seismic event.

TOP

Can spent fuel pools leak?

Spent fuel pools lined with stainless steel are designed to protect against a substantial loss of the water that cools the fuel. Pipes typically enter the pool above the level of the stored fuel, so that the fuel would stay covered even if there were a problem with one of the pipes. The only exceptions are small leakage-detection lines and, at two pressurized water reactor (PWR) sites, robust fuel transfer tubes that enter the spent fuel pool directly. The liner normally prevents water from being lost through the leak detection lines, and isolation valves or plugs are available if the liner experiences a large leak or tear.

TOP

How would you know about a leak in such a large pool of water?

The spent fuel pools associated with all but one operating reactor have liner leakage collection to allow detection of very small leaks. In addition, the spent fuel pool and fuel storage area have diverse

instruments to alert operators to possible large losses of water, which could be indicated by low water level, high water temperature, or high radiation levels.

TOP

How can operators get water back in the pool if there is a leak or a failure?

All plants have systems available to replace water that could evaporate or leak from a spent fuel pool. Most plants have at least one system designed to be available following a design basis earthquake. In addition, the industry's experience indicates that systems not specifically designed to meet seismic criteria are likely to survive a design basis earthquake and be available to replenish water to the spent fuel pools. Furthermore, plant operators can use emergency and accident procedures that identify temporary systems to provide water to the spent fuel pool if normal systems are unavailable. In some cases, operators would need to connect hoses or install short pipes between systems. The fuel is unlikely to become uncovered rapidly because of the large water volume in the pool, the robust design of the pool structure, and the limited paths for loss of water from the pool.

TOP

Do U.S. nuclear power plants store their fuel above grade? Why is this considered safe?

For boiling water reactor (BWR) Mark I and II designs, the spent fuel pool structures are located in the reactor building at an elevation several stories above the ground (about 50 to 60 feet above ground for the Mark I reactors). The spent fuel pools at other operating reactors in the U.S. are typically located with the bottom of the pool at or below plant grade level. Regardless of the location of the pool, its robust construction provides the potential for the structure to withstand events well beyond those considered in the original design. In addition, there are multiple means of restoring water to the spent fuel pools in the unlikely event that any is lost.

TOP

How are spent fuel pools kept cool? What happens if the cooling system fails?

The spent fuel pool is cooled by an attached cooling system. The system keeps fuel temperatures low enough that, even if cooling were lost, operators would have substantial time to recover cooling before boiling could occur in the spent fuel pool. Licensees also have backup ways to cool the spent fuel pool, using temporary equipment that would be available even after fires, explosions, or other unlikely events that could damage large portions of the facility and prevent operation of normal cooling systems. Operators have been trained to use this backup equipment, and it has been evaluated to provide adequate cooling even if the pool structure loses its water-tight integrity.

TOP

What keeps spent fuel from re-starting a nuclear chain reaction in the pool?

Spent fuel pools are designed with appropriate space between fuel assemblies and neutron-absorbing plates attached to the storage rack between each fuel assembly. Under normal conditions, these design features mean that there is substantial margin to prevent criticality (i.e., a condition where nuclear fission would become self-sustaining). Calculations demonstrate that some margin to criticality is maintained for a variety of abnormal conditions, including fuel handling accidents involving a dropped fuel assembly.

TOP

Questions and Answers – Dry Cask Safety

What is dry cask storage?

Dry cask storage allows spent fuel that has already been cooled in the spent fuel pool for several years to be surrounded by inert gas inside a container called a cask. The casks are typically steel cylinders that are either welded or bolted closed. The steel cylinder provides containment of the spent fuel. Each cylinder is surrounded by additional steel, concrete, or other material to provide radiation shielding to workers and members of the public.

TOP

What is an "ISFSI"?

An independent spent fuel storage installation, or ISFSI, is a facility that is designed and constructed for the interim storage of spent nuclear fuel. These facilities are licensed separately from a nuclear power plant and are considered independent even though they may be located on the site of another NRC-licensed facility.

TOP

What kind of license is required for an ISFSI?

NRC authorizes storage of spent nuclear fuel at an ISFSI in two ways: site-specific or general license. For site-specific applications, the NRC reviews the safety, environmental, physical security and financial aspects of the licensee and proposed ISFSI and, if we conclude it can operate safely, we issue a license. This license contains requirements on topics such as leak testing and monitoring and specifies the quantity and type of material the licensee is authorized to store at the site. A general license authorizes storage of spent fuel in casks previously approved by the NRC at a site already licensed to possess fuel to operate a nuclear power plant. Licensees must show the NRC that it is safe to store spent fuel in dry casks at their site, including analysis of earthquake intensity and tornado missiles. Licensees also review their programs (such as security or emergency planning) and make any changes needed to incorporate an ISFSI at their site. Of the currently licensed ISFSIs, 48 are operating under general licenses and 15 have specific licenses.

TOP

How does the NRC determine that a dry storage system is safe?

Before approving any dry storage system and issuing a Certificate of Compliance or a license, the NRC staff conducts a thorough engineering review to ensure the system design meets all necessary safety requirements. Dry storage systems must be designed to protect the public and workers from radiation exposure. In addition, dry storage systems must be able to withstand credible natural disasters and accidents. The NRC staff's dry storage system reviews are documented in safety evaluation reports, which are publicly available in the NRC Agencywide Documents Access and Management System (ADAMS). The NRC staff also conducts quality assurance inspections of vendors who design and manufacture the storage systems and operating spent fuel storage facilities to ensure compliance with the NRC's safety requirements.

For more information, see NUREG/BR-0528

TOP

What are the requirements for the selection and use of a dry storage system at an NRC licensed commercial power reactor site?

A licensee's selection of a dry cask storage system is based on the operational needs of a specific reactor site (A list of approved casks can be found in 10 CFR 72.214). A licensee must first determine whether a particular system addresses the storage site's parameters, including analyses of potential earthquake intensity and tornado missiles. A licensee must provide reasonable assurance that the location's conditions meet the necessary safety requirements for adequate protection. The evaluation requirements for a dry storage system user can be found in 10 CFR 72.212.

TOP

What Risk Assessments have been conducted for dry storage systems?
The NRC and the Electrical Power Research Institute (EPRI) have performed risk assessments for dry storage systems. These analyses considered the release of radioactive gases and found the radiation doses to be below NRC's safety requirements. The NRC staff also evaluated a post-accident release of radioactive gases from breached storage canisters that contain damaged fuel assemblies. EPRI has also conducted a risk assessment regarding the radiological risks to the public during the life cycle of a bolted spent fuel cask. NUREG-1864 assesses a comprehensive list of initiating events, including dropping the cask during handling, and external events during onsite storage (such as earthquakes, floods, high winds, lightning strikes, accidental aircraft crashes, and pipeline explosions). All of these studies concluded that the risks of the public receiving a dose above regulatory limits is very low.

For more information, see the following:

- NUREG-1864
- EPRI Technical Report 1002877

TOP

How do the NRC requirements ensure that dry storage systems do not release radioactive material and expose workers and members of the public to radiation?

The NRC requires dry storage systems to meet NRC safety requirements at all times, including during or after a design basis accident. A design basis accident is any event that could significantly affect the storage system. Accident conditions include events such as fuel rod rupture and air flow blockage, as well as natural phenomena like earthquakes, burial under debris, lightning strikes, and other phenomena (e.g., seiches, tsunamis, and hurricanes). Different accident conditions are evaluated as appropriate depending on the storage cask's location. NRC requirements in 10 CFR 72.104 define annual dose limits for normal operations and anticipated events, while requirements in 10 CFR 72.106 define dose limits for a design basis accident. These dose limits do not pose a significant safety concern to workers or the public, and are a fraction of the average annual dose received from background radiation.

TOP

How are dry storage systems inspected?

Nondestructive examination (NDE) methods for the inspection of canisters already exist and have been used in the nuclear industry for decades. These NDE methods include visual testing (VT), Eddy current testing (ECT), and Ultrasonic testing (UT). ECT utilizes magnetic fields to identify cracks and defects. Similarly, UT utilizes sound waves as the method for detection. Together, the three methods can detect and characterize potential aging effects like localized corrosion. Methods to apply existing NDE techniques to stainless steel canisters have been developed, and currently are being tested by both the Electrical Power Research Institute (EPRI) and dry storage system manufacturers.

Additional information is available in the following EPRI reports:

- EPRI-3002008234
- EPRI-3002010617
- EPRI-3002010621

TOP

What can remote visual testing be used to detect?

Remote visual testing (RVT) is a nondestructive way to detect cracking, corrosion, wear and component failures. The ability of RVT methods to detect cracking was reviewed and documented in NUREG/CR-7246. Crack size was found to be an important feature that limits the detection of cracks by RVT. Very small cracks are harder to detect using RVT. Detection by RVT is also challenged when cracks are located in the proximity of surface features, such as grinding marks or weld ripples. RVT is still a viable inspection method despite its limitations. Because the detection of CISCC cracks on canisters using RVT could be challenging, the example aging management programs developed by NRC staff and aging management guidance developed by the Electrical Power Research Institute (EPRI) have relied on indications of localized corrosion, such as pitting, that can be reliably detected using visual testing methods.

For more information, see the following:

- NUREG/CR-7246
- NUREG-2214
- EPRI-3002008193

TOP

How does the NRC conduct oversight of Licensees?

Licensees are responsible for operating their facilities safely. The NRC verifies licensees' compliance with safety regulations through its inspection program. This includes inspections of operating facilities and cask vendors. The frequency of these inspections is based on the licensee's performance and the presence of activity (cask loadings, extreme weather conditions, etc.). The NRC requires prompt corrective action by the licensee if a safety problem or failure to comply with requirements is discovered. Enforcement action may follow depending on the severity of the inspection findings.

For more information on how specifically inspections are done, see the NRC Inspection Manual, Manual Chapter 2690

TOP

How does the NRC verify that canisters are properly loaded in accordance with their NRC Certificate of Compliance?

Before the licensee has loaded a single canister, the NRC inspects the licensee's spent fuel loading procedures by observing and assessing the implementation of those procedures during a "dry run" rehearsal before actual loading is performed. The NRC also observes the initial cask loading. This means the very first cask loaded by a licensee is always observed. NRC inspectors generally observe and review licensee's identification, parameters, and characteristics of each fuel assembly. Verification is also performed through review of procedures that lead to the selection and verification of fuel assemblies prior to each loading. After the first loading has been observed, inspectors will periodically observe future cask loadings to ensure canisters are still being properly loaded. If a misloading is identified the licensee must immediately conduct an evaluation to show the NRC the loading still meets the acceptance criteria. In no misloading case has there ever been a safety concern.

TOP

How can the fuel or internal components be inspected on canisters with welded lids?

At this time there are no methods available for inspecting the internal components of welded stainless steel canisters once they are loaded. Several measures are taken during the loading process to ensure there will be no need to re-open a welded canister. Each canister is leak tested prior to use to ensure the inert helium environment will remain inside the canister. The inert environment prevents the stored spent fuel from degrading and eliminates the need to inspect the fuel or the interior of the canister. If there is a safety need to open a welded canister, there is a procedure approved by NRC staff in the dry storage system's safety analysis report.

TOP

How would welded stainless steel canisters be repaired if necessary?

In the unlikely event that a canister repair would be needed, corrective actions would be performed on a case-specific basis for the affected dry storage system component. Corrective actions may be proposed to mitigate an identified degradation before the canister integrity is compromised, or to bring a canister back into compliance if the degradation has compromised the canister integrity. The licensee would propose corrective actions to the NRC in either case, and NRC staff would evaluate whether the corrective actions are sufficient to preserve the intended safety functions of the dry storage system and maintain compliance with the regulations of 10 CFR Part 72. Proposed repair methods also require demonstration and compliance with an NRC-approved quality assurance program.

TOP

Questions and Answers – Waste Confidence & Future Plans

How long is spent fuel allowed to be stored in a pool or cask?

NRC regulations do not specify a maximum time for storing spent fuel in pool or cask. The agency's “waste confidence decision" expresses the Commission's confidence that the fuel can be stored safely in either pool or cask for at least 60 years beyond the licensed life of any reactor without significant environmental effects. At current licensing terms (40 years of initial reactor operation plus 20 of extended operation), that would amount to at least 120 years of safe storage.

However, it is important to note that this does not mean NRC "allows" or "permits" storage for that period. Dry casks are licensed or certified for 20 years, with possible renewals of up to 40 years. This shorter licensing term means the casks are reviewed and inspected, and the NRC ensures the licensee has an adequate aging management program to maintain the facility.

TOP

What is the plan for storage of spent nuclear fuel going forward? Will on-site storage continue to be the way for the foreseeable future?

The U.S. policy for nuclear waste management, as set forth in the Nuclear Waste Policy Act, is for permanent disposal of spent fuel in a deep underground geological repository. Decades of scientific research supports the use of a repository for disposal of spent fuel. Federal responsibility for siting and building a repository remains national policy. The NRC acknowledges the challenges encountered over the years in siting and licensing the proposed repository at Yucca Mountain. The Commission remains confident that a repository will be built. The Commission does not consider that accumulated spent fuel will be stored permanently at current or former reactor sites and does not endorse permanent storage at reactor sites.

Although the NRC considers that 25 to 35 years is a reasonable timeframe for repository development, it acknowledges that there is sufficient uncertainty in this estimate that the possibility that more time will be needed cannot be ruled out. International and domestic experience have made it clear that technical knowledge and experience alone are not sufficient to bring about the broad social and political acceptance needed to construct a repository. The time needed to develop a societal and political consensus for a repository could add to the time to site and license a repository, or overlap it to some degree.

TOP

These casks are already pretty old and could be storing spent fuel for decades to come. How can you protect them from deteriorating over time, especially from effects that have been seen at other nuclear installations such as alkali-silica reaction or chloride-induced stress corrosion cracking?

Dry cask storage systems have been used at U.S. nuclear power plants for more than 30 years with an excellent safety record. Part of the reason for that success is the robust design of the systems. Another reason is proper care and maintenance, including implementation of aging management programs (AMPs) required by the NRC.
The NRC conducted an extensive review of the materials used in dry cask storage systems, looking at how these materials might degrade over time. This review was documented in NUREG-2214. The NRC reviewed specific dry cask storage system designs, and the environments in which the systems operate. The report describes the scientific methods used to determine the likely effects of aging on the storage systems, and what might cause those effects. It also includes examples of generic AMPs licensees may use to develop their own programs. Additional guidance on aging management for dry storage systems was published in NUREG-1927. NRC inspectors examine a licensee's AMPs to verify that any potential degradation is quickly identified, and corrective actions taken to ensure the storage cask continues to function properly.

Two ways dry storage systems could possibly degrade over time are alkali-silica reaction (ASR) on concrete, and chloride-induced stress corrosion cracking (CISCC) of welded stainless steel canisters. No ASR has been reported on a dry storage system to date, though it is something licensees must include in

their AMPs. NRC staff research on CISCC concluded that the risk is not credible during the first 20 years of operation because of the long time needed for cracks to grow through the stainless steel canister wall. After 20 years, CISCC is covered by the AMP. The Electrical Power Research Institute (EPRI) has also conducted a thorough assessment of the potential for CISCC in dry storage system canisters.

TOP

How are the long-term impacts of onsite storage of spent fuel analyzed, and what measures are taken to minimize potential impacts on public health and safety?

All storage systems approved by the NRC have been reviewed to ensure they meet all the regulatory safety requirements. These requirements address the credible hazards from natural disasters and accidents that the spent fuel storage systems may encounter. Long term, the NRC requires dry storage system users to have Aging Management Programs (AMPs) to ensure safety. NUREG-1927 and NUREG-2214 provide more detailed information about aging management activities for dry storage systems. These guidance documents will continue to be updated as necessary.

NRC staff also conduct an environmental review of each independent spent fuel storage installation (ISFSI) to comply with the National Environmental Policy Act (NEPA). The NRC's NEPA requirements are in 10 CFR Part 51. In 2014, NRC staff evaluated the environmental impacts of continued storage of spent fuel. This evaluation is documented in NUREG-2157 and shows that the long-term storage of spent fuel has a low environmental impact.
For more information, see the following:

- NUREG-1927
- NUREG-2214
- NUREG-2157

TOP

After a plant is decommissioned there will be no infrastructure to handle the repackaging of spent fuel if the storage systems need replacement. Is there a plan for this contingency, and what are the safety implications of reopening the storage cask?

Storage casks should not be opened unless there is a specific safety need. Most welded stainless steel canisters are designed to be transportable inside a specifically designed transportation overpack. This allows fuel to be transported without directly handling the fuel. The canisters are leak tested and this assures that the helium environment will be maintained inside the canister. A helium environment is important because helium is an inert gas, meaning it does not undergo chemical reactions. If safety issues are identified, it is the responsibility of the licensee to propose corrective actions, and the NRC's responsibility to ensure these actions maintain the safety functions of the storage system. Each specific dry storage system has specific procedures for opening the canister outlined in the dry storage system or the independent spent fuel storage installation (ISFSI) safety analysis report. These procedures are reviewed by NRC staff.

TOP

Questions and Answers – Security

What about security? How do you know terrorists won't use all of this waste against us?

For spent fuel, as with reactors, the NRC sets security requirements and licensees are responsible for providing the protection. We constantly remain aware of the capabilities of potential adversaries and threats to facilities, material, and activities, and we focus on physically protecting and controlling spent fuel to prevent sabotage, theft, and diversion. Some key features of these protection programs include intrusion detection, assessment of alarms, response to intrusions, and offsite assistance when necessary. Over the last 20 years, there have been no radiation releases that have affected the public. There have also been no known or suspected attempts to sabotage spent fuel casks or storage facilities. The NRC responded to the terrorist attacks on September 11, 2001, by promptly requiring security enhancements for spent fuel storage, both in spent fuel pools and dry casks.

TOP

How are dry storage systems canisters at ISFSIs protected against terrorism such as the September 11, 2001 terrorist attacks using hijacked airplanes?

The best defense against hijacked airplanes is airport security, enforced by the Department of Homeland Security's (DHS) Transportation Safety Administration. DHS, the U.S. military, and the intelligence community are responsible for the defense of the country. The NRC regularly works with these agencies to assess the threat environment, and is always ready to alert its licensees if a specific, credible threat is identified.

Security requirements at NRC-licensed facilities are based on the potential threat level and the potential consequences of an event. The NRC details the security requirements for physical protection of spent fuel storage in 10 CFR Part 73 and 10 CFR Part 72. Further orders also provide additional security measures. Protection from, and responses to, security-related events are addressed in the licensee's NRC-approved Physical Security Plan, which is not publicly available. An independent spent fuel storage installation (ISFSI) licensee must comply with the security requirements which are implemented in their approved Physical Security Plan.

Over the past 20 years, there have been no known or suspected attempts to sabotage, or steal radioactive material from storage casks at ISFSIs, or to directly attack an ISFSI. Nevertheless, the NRC is continually evaluating threats to stay best prepared. Licensees are routinely inspected to ensure they are following their NRC-approved Physical Security Plan. NRC staff have conducted security assessments for ISFSIs using several storage cask designs that were representative of most currently certified designs. The resulting assessments formed the basis for the NRC's conclusion that there was no need for further security measures at ISFSIs beyond those currently required.

For more information, see Frequently Asked Questions About Security Assessments at Nuclear Power Plants.

TOP

Questions and Answers – Emergency Planning

Are potential seismic effects considered in the assessment of canisters for continued operation? –EP

Yes, approved canister designs used at a specific independent spent fuel storage installation (ISFSI) location address the credible seismic hazards of that location. The canisters must maintain containment of the spent fuel under the predicted seismic loads for each location. In addition, the radiation exposure limits, thermal limits, confinement barrier integrity, structural performance, and nuclear criticality safety

must be maintained. These requirements continue throughout the life of the dry storage systems and are maintained and verified by aging management activities and inspections.

TOP

What are the emergency plans for nuclear waste at an ISFSI in the case of mishandling, leaks, natural disasters or acts of terrorisms?

An emergency plan for an independent spent fuel storage installation (ISFSI) is required by 10 CFR 72.32(c). The emergency plan identifies the actions to be taken to address a release and make the consequences less severe, regardless of the event. However, there is no credible accident scenario involving dry cask storage that would result in widespread consequences outside the facility boundary. That's because unlike operating power reactors, dry cask storage systems do not have the thermal or kinetic energy to spread radioactive contamination over a large area in the highly unlikely event a storage canister is breached. Emergency plans for ISFSIs are publicly available in ADAMS. Protection from and responses to security-related events are addressed in a licensee's NRC-approved Physical Security Plan, which are not publicly available.

For more information, see Frequently Asked Questions About Emergency Preparedness and Response.

TOP

What emergency plans are required for spent fuel storage facilities at nuclear power plants undergoing decommissioning or sites that have completed decommissioning?

Decommissioning reactors continue to be subject to the NRC's emergency planning requirements. For some period of time after the licensee ceases reactor operations, offsite emergency planning will be maintained. This period of time depends on when the reactor was last critical as well as site-specific considerations. Offsite emergency planning may be eliminated when the fuel has been removed from the reactor and placed in the spent fuel pool, and sufficient time has elapsed, such that there are no longer any postulated accidents that would result in offsite dose consequences large enough to require offsite emergency planning. There would be no requirement to maintain offsite systems to warn the public. Onsite emergency plans will be required for both the spent fuel pool and the Independent Spent Fuel Storage Installations, but offsite plans will not be required. If, however, an operating plant is located at the same site as the decommissioning plant, the emergency preparedness plans will still be in effect for the operating plant.

Although offsite emergency planning at a decommissioned site may no longer be required, licensees maintain offsite contacts since any emergency declaration requires notification of state and local officials as well as the NRC. In addition, due to the typically reduced staffs at a decommissioning facility they may rely even more on offsite assistance for fire, security, medical or other emergencies. These reduced EP requirements would remain in effect as long as fuel is onsite.

(Note: This general description also applies to emergency planning for specifically licensed ISFSIs; those requirements are spelled out in detail in 10 CFR 72.32.)

TOP

Page Last Reviewed/Updated Tuesday, August 27, 2019

EXHIBIT 29

From: MARK MORGAN <Mark.Morgan@sce.com>
Sent: Friday, March 29, 2019 4:25 PM
To: Brookhart, Lee; Plotter, Jason; Simpson, Eric; Smith, Chris; Wise, John; Davis, Marlone; Katanic, Janine; Howell, Linda; Doug Bauder; ALBERT BATES
Cc: MARK MORGAN
Subject: [External_Sender] Latest products posted to the reading room

All,

SONGS has just posted the following products to the CERTREC Electronic Reading Room for your review:

1. The MPC Visual Assessment Report
2. A revised HI-2188437 to incorporate results of the Visual Assessment Report
3. A change to the 72.212 evaluation to evaluate incidental contact wear for ASME Code Compliance, and
4. An associated 72.48 evaluation.

If files are sorted by "name" in the reading room, they will be grouped together alphabetically under "Post Visual Assessment..."

In addition, Al asked me to pass along the latest version of our statement on Code Compliance, previously transmitted to you on Monday. The response has been updated, and is attached to this email.

Please let me know if you have any questions regarding this.

Thanks,
Mark
(949) 368-6745

NRC Review Question Response Form

Note 1: Complete a separate form for each inspector question.

Note 2: The item tracking number will be generated when the record is entered into the inspection database.

Question Title: Clarification of ASME Section 3 in Licensing Basis

Tracking Number: 11A AR Number: 0319-53473-3 Date Initiated: 03/21/2019

Holtec Support Required: Yes__ or No ___

Question description:

Appendix B Technical Specification 3.3 requires, that the AMSE BPVC, 2007, is the governing Code for the MPC. Additionally, Appendix B Table 3-1 tie the canister and FSAR to the requirements of ASME Section III in many areas.

The original FSAR statement for no scratches mirrored the CoC/TS design basis that no scratches would ensure the code adherence to ASME Section III.

Now under 72.48, a design change is needed to deviate to allow scratches. But instead of using ASME BPVC code criteria to inspect the canister and properly disposition the defects which would maintain conformance to the code, the calculation utilizes Archard's wear equation to bound the condition. I just don't see how that meets CoC.

Now I understand, how SCE has argued, it is not a methodology. I think it is more of CoC and Appendix B change, myself. Essentially, the change is adding an alternative to the code to not have to do inspections and repair these new defects. Alternatives to the code can only be done via license amendment. Or maybe per TS Appendix B 3.3.2.

NB-4131 "Material originally accepted on delivery in which defects exceeding limits of NB-2500 are known or discovered during the process of fabrication or installation is unacceptable. The material may be used provided the condition is corrected in accordance with the requirements of NB-2500

ASME Section III NB-2538, "Elimination of Surface Defects" requires that defects are required to be examined by either magnetic particle or liquid penetrant method to ensure that the defect has been removed or reduced to an imperfection of acceptable size."

Instead of doing that (which I understand is impossible) which would maintain code compliance, the 72.48 deviates using a calculational method to bound the defect. The only "method" that should be used to disposition these defects is some method allowed or described in the BPVC code or the licensee would need an alternative to the code to maintain compliance with the regulatory licensing basis.

NRC Review Question Response Form

Requested Clarification (If needed): None

SONGS / Holtec Response:

NOTE: For clarity, the NRC question (comment) is separated by paragraph and a response to each is provided.

NRC Comment 1

Appendix B Technical Specification 3.3 requires, that the AMSE BPVC, 2007, is the governing Code for the MPC. Additionally, Appendix B Table 3-1 tie the canister and FSAR to the requirements of ASME Section III in many areas.

Response to Comment 1

It is agreed that the ASME BPVC, 2007 is the governing code for the MPC and that C of C Appendix B, "Approved Contents and Design Features," Table 3-1 ties the canister and FSAR to the requirements of Section III in many areas. However, other sections of the code apply as well and the relationship is described below.

Section III is the construction code portion of the ASME B&PV Code. It assumes that the other parts of the Code are also involved as appropriate. ASME Code material specifications are in Section II. They are selected in accordance with Section III. NDE is generally performed in accordance with Section V. Welding is performed in accordance with Section IX. Preservice examinations required by the component specifications to be done by the manufacturer are often performed in accordance with Section XI. Typically, the primary jurisdiction of the Section III construction code ends when a component is stamped. Because the MPC is not actually stamped, Holtec considers jurisdiction of Section III ends when the MPC leaves the manufacturer. Although Appendix B of the C of C is silent on which Section of the ASME Code applies during inservice inspections, use of Section XI, as selected by Holtec, is typical throughout the nuclear industry and is not prohibited by the C of C. Therefore, the ASME Code Section XI has jurisdiction after the MPC leaves the manufacturer.

NRC Comment 2

The original FSAR statement for no scratches mirrored the CoC/TS design basis that no scratches would ensure the code adherence to ASME Section III.

Response to Comment 2

There is no indication in the CoC, its Appendices (Technical Specifications or Approved Contents and Design Features), or NRC SER that the statement in Chapter 9 of the FSAR related to no risk of scratching was considered in the NRC's evaluation of the ASME Code compliance of the MPC.

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There is no violation of ASME Section III requirements, nor any cause for repair activities, stemming from minor scratches or wear marks that result from incidental contact between the MPC and the CEC internal features during download operations at site.

HI-STORM UMAX FSAR Rev. 4: 9.5.vii states

> *Because the MPC insertion (and withdrawal) occurs in the vertical configuration with ample lateral clearances, there is no risk of scratching or gouging of the MPC's external surface (Confinement Boundary). Thus the ASME Section III Class 1 prohibition against damage to the pressure retaining boundary is maintained.*

The Section III requirements for pressure containing plate materials is that surface defects will be removed (NB-2538). In NCA-9000, *defective material* is defined as material that does not meet specified requirements. Similarly a defect is defined in general as a rejectable flaw and a flaw is defined as an imperfection or unintentional discontinuity that is detectable by visual, surface or volumetric methods (Section XI Glossary, IWA-9000 (1992)).

A scratch, if it occurred during installation, would not be a defect requiring repair per the Code. A scratch is a non-conformance and the engineering disposition concluded that scratches are not rejectable due to potential effects on peak stresses, as explained in HI-2188437. This is because localized scratches or wear marks are only capable of producing peak stresses, which are only objectionable from a fatigue or brittle fracture standpoint. The HI-STORM UMAX and FW FSARs (Table 3.1.10 of both address fatigue and HI-STORM FW FSAR Section 3.4.5 for brittle fracture) explain why neither fatigue nor brittle fracture present any risk to a MPC.

A scratch would not be rejectable due to interference with material testing in NB-2000 since all of these tests would be completed prior to canister delivery.

Therefore, the only remaining cause (without further analysis) of rejection of a scratch located on the exterior of the canister wall generated during installation would be a condition where the amount of localized wall thinning was below an allowable wall thickness based on Section III.

If a scratch during installation occurs, it can, under Section XI jurisdiction, either be dispositioned as a scratch (i.e., since it not a planar flaw) by reverting back (in accordance with IWA-3100 (b)) to the Construction Code, which would be Section III; or, if desired, be dispositioned by Section XI, Table IWB-3514-1, as if it were a planar flaw (which is more conservative than Section III). The information supplied by SCE and Holtec to date is not intended to disposition any indication; but, to provide assurance that any potential scratches will remain well within ASME Code allowable limits. So the SONGS canister scratch could be acceptable down to a minimum allowable wall under Section III. And the Holtec MPC with 0.500 inch wall could, if desired, allow a scratch as if a planar flaw that was up to 10% of nominal wall thickness (an allowed wall of 0.450 inches).

This means that the 0.625 inch nominal wall for a SONGS canister could, using engineering judgment, be reduced without further analysis by 0.175 inches to 0.450 inches, which is an allowable wall based on the licensed 0.500 inch baseline UMAX MPC as discussed in HI-2188437.

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A scratch that might be formed during incidental contact of an MPC wall with the divider shell inside the cavity enclosure container during downloading would not result in a rejectable flaw condition, considering the large allowable margin for such localized thinning. This is based on engineering judgment and operational experience. Knowledge of basic wear principles with two soft materials having incidental contact under light lateral loads and many years of operating experience with acceptable canister loading of horizontal canisters inform this judgment. Scratches of a light nature, though somewhat likely, present no risk since the impact is negligible.

NRC Comment 3

Now under 72.48, a design change is needed to deviate to allow scratches. But instead of using ASME BPVC code criteria to inspect the canister and properly disposition the defects which would maintain conformance to the code, the calculation utilizes Archard's wear equation to bound the condition. I just don't see how that meets CoC.

Response to Comment 3

ECO-5021-042 is not a design change. It is a proposed change to clarify the HI-STORM UMAX FSAR. The ECO and supporting 72.48 are explicit in this regard. They further note that they are evaluated as if they were a design change to assure a more comprehensive documented review.

A change is not required to allow scratches since the FSAR statement that there is no risk of damage to the ASME Section III Class 1 pressure retaining boundary that might result from scratching remains valid.

It is not necessary to conclude that the intent of the FSAR was to state that no scratches would occur since incidental contact could occur. More likely the intent was to note that, compared to other designs with much higher contact loads and no clearance, there was negligible risk that shallow scratches in the vertical designs would be rejectable. When SCE and Holtec were asked (after the August 3, 2018 event) to justify this engineering judgment, accepted engineering practices were used for the estimation of scratches as well as laboratory tests and canister inspections. This was not a required calculation for design purposes, but the use of standard engineering explanations, all of which substantiated the initial judgment.

NRC Comment 4

Now I understand, how SCE has argued, it is not a methodology. I think it is more of CoC and Appendix B change, myself. Essentially, the change is adding an alternative to the code to not have to do inspections and repair these new defects. Alternatives to the code can only be done via license amendment. Or maybe per TS Appendix B 3.3.2.

Response to Comment 4

It is not correct to call these slight scratches "defects". By the definition of the ASME code, a defect is a flaw that is rejectable. None of these scratches approach criteria that require removal or repair. That judgment has been substantiated by accepted wear laws, first principles,

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laboratory tests, operating experience, and examination of installed loaded canisters that this judgment was and still is valid.

As noted in the Response to Comment 4, questions regarding the judgment arose from various stakeholders following the hang-up of the MPC on August 3, 2018. It was apparently presumed that the lateral loads during passage of the MPC into the cavity enclosure container must be higher than previously considered. After assessing the actual loads and their effect on the surfaces of the canister, the original judgment was validated.

NRC Comment 5

NB-4131 "Material originally accepted on delivery in which defects exceeding limits of NB-2500 are known or discovered during the process of fabrication or installation is unacceptable. The material may be used provided the condition is corrected in accordance with the requirements of NB-2500.

Response to Comment 5

SCE and Holtec agree with this ASME Code requirement. It is appropriately implemented by the fabricator as an attribute of the manufacturing process and its controls. Appropriate documentation is provided to Holtec and SCE certifying compliance with FSAR invoked requirements of the ASME Code.

As previously noted, no defects (i.e., rejectable flaws) were discovered or are anticipated during the process of installation. Therefore no corrections are required per NB-2500.

NRC Comment 6

ASME Section III NB-2538, "Elimination of Surface Defects" requires that defects are required to be examined by either magnetic particle or liquid penetrant method to ensure that the defect has been removed or reduced to an imperfection of acceptable size."

Response to Comment 6

No defects (rejectable flaws) have been identified that have resulted from scratches or are expected to result from scratches due to incidental contact during down-loading. The bounding scratches estimated in response to the various inquiries are theoretical projections not identified flaws.

This is consistent with the judgment in the FSAR, and validated by the means explained above. The requirement of NB-2538 might have removed a scratch during construction if it interfered with the ability to complete the surface or volumetric material examinations of the pressure boundary material.

Once this had been completed and the canister delivered, a similar surface defect occurring during installation would not need to be removed because these material examinations had already been completed.

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NRC Review Question Response Form

NRC Comment 7

Instead of doing that (which I understand is impossible) which would maintain code compliance, the 72.48 deviates using a calculational method to bound the defect. The only "method" that should be used to disposition these defects is some method allowed or described in the BPVC code or the licensee would need an alternative to the code to maintain compliance with the regulatory licensing basis.

Response to Comment 7

As previously noted no "defects" due to incidental contact are anticipated. The calculational methods are tools to estimate potential scratch depth and are in no way a means to disposition any defect; real or projected.

Neither the identification nor removal of shallow scratches, wear or rub marks due to installation is required to maintain compliance with ASME Section III or the ASME B&PV Code generally.

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Response provided date / time: 3/23/19

EXHIBIT 30

Includes Errata dated June 5, 1981.

NUREG-0490

Final Environmental Statement

related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3

Docket Nos. 50-361 and 50-362

Southern California Edison Company
San Diego Gas & Electric Company
The City of Riverside
The City of Anaheim

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

April 1981

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JUN 5 1981

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Gentlemen:

SUBJECT: ISSUANCE OF ERRATA TO FINAL ENVIRONMENTAL STATEMENT (SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3)

The Nuclear Regulatory Commission has issued the enclosed errata to the Final Environmental Statement (FES) related to the San Onofre Nuclear Generating Station, Units 2 and 3. Although implicit in the FES, this errata clarifies the staff's consideration of reasonable alternatives to the proposed action. The enclosed discussion should be added to Section 10.1.

Sincerely,

Frank J. Miraglia

Frank J. Miraglia, Acting Chief
Licensing Branch No. 3
Division of Licensing

Enclosure:
Errata (20 copies)

cc: See next page.

ERRATA

FINAL ENVIRONMENTAL STATEMENT

SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3

ALTERNATIVES TO THE PROPOSED ACTION

During the construction permit stage, the staff analyzed alternative sites, plant designs, and methods of power generation, including the alternative of not adding the production capacity. The staff concluded, based on its analysis of these alternatives, as well as on a cost-benefit basis, that additional capacity was needed that a nuclear-fueled plant would be environmentally acceptable, and that SONGS, at a specified site and of a specified design, were acceptable from both economic and environmental perspectives. Since that time, construction of SONGS has been nearly completed and many of the economic and environmental costs associated with the construction of the facility have already been incurred and must be viewed as "sunk costs" in any prospective assessment.

The staff believes that the only reasonable alternative to the proposed action of issuance of operating licenses for SONGS appropriately considered at this stage is denial of the operating licenses for the facility, thereby not permitting the addition of the essentially built generating capacity to the applicant's generating system. Alternatives such as construction of the units at another site, extensive modifications to the facility, or construction of facilities utilizing different energy sources would each require additional construction activity with its accompanying economic and environmental costs. Therefore, unless major safety or environmental concerns resulting from operation of SONGS are revealed that were not evident and considered during the construction permit review, these alternatives are unreasonable as compared to operating the already constructed facility. No such concerns have been identified with respect to operation of SONGS.

The continued need for the capacity to be generated by SONGS is discussed in section 8 of this FES.

Accordingly, the staff concludes that the preferrable alternative is operation of SONGS.

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NUREG-0490

Final Environmental Statement

related to the operation of
San Onofre Nuclear Generating Station,
Units 2 and 3

Docket Nos. 50-361 and 50-362

Southern California Edison Company
San Diego Gas & Electric Company
The City of Riverside
The City of Anaheim

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

April 1981

SUMMARY AND CONCLUSIONS

This Environmental Statement was prepared by the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation (hereinafter referred to as the staff).

1. The action is administrative.

2. The proposed action is the issuance of Operating Licenses jointly to the Southern California Edison Company (SCE) and the San Diego Gas and Electric Company (SDG&E) for the startup and operation of Units 2 and 3 of the San Onofre Nuclear Generating Station, adjacent to San Onofre Unit 1, located on the Pacific coast in the State of California, County of San Diego (Docket Nos. 50-361 and 50-362).

   The City of Anaheim, California, and the City of Riverside, California, have recently been added as co-holders of the Construction Permits for San Onofre 2 and 3, and will soon request to be included as applicants for Operating Licenses. The four groups are co-owners of the facility, and are referred to herein as the applicant.

   Both units will employ pressurized water reactors to produce up to 3410 thermal megawatts (MWt) each. Steam turbine-generators will use this heat to provide a net power output of up to 1106 electrical megawatts (MWe) each. The exhaust steam will be cooled by once-through flow of water pumped from the Pacific Ocean and returned to it through a diffuser-type system.

3. The information in this statement represents the second assessment by the staff of the environmental impacts associated with the San Onofre Nuclear Generating Station, Unit Nos. 2 and 3, pursuant to the requirements of the National Environmental Policy Act (NEPA) of 1969 and 10 CFR Part 51 of the Commission's Regulations. After receipt of an application (1970) to construct this plant, the staff carried out a review of impacts that would occur during the construction and operation of this plant. This evaluation was issued as a Final Environmental Statement in March 1973. As a result of this environmental review, a staff safety review, an evaluation by the Advisory Committee on Reactor Safeguards, and a public hearing in San Diego, California during January 16-24, 1973 and May 14-22, 1973, and in San Clemente, California, during March 13-15, 1973, the U.S. Atomic Energy Commission (AEC) [now Nuclear Regulatory Commission (NRC)] issued permits in October 1973 for the construction of Units 2 and 3. As of December 1980, Unit 2 was approximately 97% complete and Unit 3 was approximately 68% complete. The applicant has applied for licenses to operate the nuclear units and has submitted the required safety and environmental reports to support this application (March 1977). The staff has reviewed the activities associated with the proposed operation of these units and their potential impacts, both beneficial and adverse, are summarized as follows:

   a. Cooling water heated to about 11°C (20°F) above inlet temperature will be discharged from each unit to the Pacific Ocean at a rate of about 53 m^3/s (846,000 gpm) (Sect. 3.2.2). The heated water may result in the destruction of at least a portion of the San Onofre Kelp Bed during the summer months. However, the long-term thermal impacts are not likely to be severe (Sect. 5.4.2.1) and violations of the state thermal standards are unlikely (Sect. 5.3.1).

   b. An impact on aquatic resources may occur in the cooling water intake structure through entrainment of plankton and impingement of fish. These losses are not expected to have a significant impact on the overall biotic populations in the area.

   c. Chemical effluents from Units 2 and 3 should cause only minimal impact in the area of the discharge, and no significant impact on the aquatic biota in the Pacific Ocean (Sect. 5.4.2.2).

   d. The program for operation and maintenance of transmission lines has been designed to reduce environmental impact. Existing transmission lines and towers will be used where possible. About 7.2 ha (17.8 acres) will be occupied by new towers, access roads, and switchyards (Sect. 2.2.2).

   e. About 16 ha (40 acres) of coastal land which could otherwise have been used primarily for recreation or maintained as wildlife habitat will be occupied by Units 2 and 3 (Sect. 2.2.2).

f. The removal of approximately 1.4 km (0.85 mile) of beach from unrestricted public use, as required by the Construction Permit, is a significant cost of operation.

g. No detectable impacts are anticipated from releases of radioactive materials as a consequence of normal operation (Sect. 5.5.1.6).

h. The risk associated with accidental radiation exposure is very low (Sect. 7).

i. Nothing of known local historic or archaeological interest will be disturbed on the plant site by the operation of Units 2 and 3. A survey along the transmission right-of-way evaluated 41 archaeological sites; of these 23 will be nominated for inclusion in the National Register of Historic Places (Sect. 5.2).

4. The following Federal and State agencies were asked to comment on the Draft Environmental Statement:

- Department of Agriculture
- Department of the Army (Corps of Engineers)
- Department of Commerce
- Department of Energy
- Department of the Interior
- Department of Health, Education and Welfare
- Department of Housing and Urban Development
- Department of Transportation
- Environmental Protection Agency
- Federal Energy Regulatory Commission
- Advisory Council on Historic Preservation
- California Department of Health (Water Pollution Control Commission, Air Pollution Control Commission, Occupational Health Office)
- California Department of Natural Resources
- California Department of Parks and Recreation

Comments on the Draft Environmental Statement were received from the following:

- Department of Agriculture, Economics, Statistics, and Cooperatives Service
- Department of Agriculture, Science and Education Administration
- Department of Agriculture, Soil Conservation Service
- Department of the Army, Corps of Engineers
- Department of Commerce
- Department of Energy, Federal Energy Regulatory Commission
- Department of Health, Education and Welfare
- Department of Housing and Urban Development
- Department of the Interior
- Environmental Protection Agency
- Mr. Marvin I. Lewis
- Rourke and Woodruff Law Offices
- Richard J. Wharton
- Union of Concerned Scientists
- Southern California Edison Company
- Frank H. Grundel
- San Diego Association of Governments

Copies of these comments are appended to this Final Environmental Statement as Appendix A. The staff has considered these comments, and the responses are located in Section 11.

5. This Final Environmental Statement was made available to the public, to the Environmental Protection Agency, and to other specified agencies in April 1981.

6. On the basis of the analysis and evaluation set forth in this statement, and after weighing the environmental, economic, technical and other benefits against environmental costs and after considering available alternatives at the construction stage, it is concluded that the action called for under NEPA and 10 CFR Part 51 is the issuance of operating licenses for Units 2 and 3 of the San Onofre Nuclear Generating Station subject to the following conditions for the protection of the environment:

   (A) License Conditions
   Before engaging in activities that may result in a significant adverse environmental impact that was not evaluated or that is significantly greater than evaluated in this Environmental Statement, the licensee shall provide written notification of such activities to the Office of Nuclear Reactor Regulation and receive written approval from that office before proceeding with such activities.

   (B) Significant Environmental Technical Specification Requirements

      (1) If, during the operating life of the Station, effects or evidence of potential irreversible damage are detected, the licensee will provide to the staff an analysis of the problem and a proposed course of action to alleviate the problem.

      (2) The licensee will carry out the operational environmental monitoring programs outlined in Section 6.

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FOREWORD

This environmental statement was prepared by the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation (hereinafter referred to as the staff) in accordance with the Commission's regulations, 10 CFR 51, which implement the requirements of the National Environmental Policy Act of 1969 (NEPA).

The NEPA states, among other things, that it is the continuing responsibility of the Federal government to use all practicable means, consistent with other essential considerations of national policy, to improve and coordinate Federal plans, functions, programs, and resources to the end that the Nation may:

- Fulfill the responsibilities of each generation as trustee of the environment for succeeding generations.
- Assure for all Americans safe, healthful, productive, and aesthetically and culturally pleasing surroundings.
- Attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences.
- Preserve important historic, cultural, and natural aspects of our national heritage, and maintain, wherever possible, an environment that supports diversity and variety of individual choice.
- Achieve a balance between population and resource use which will permit high standards of living and a wide sharing of life's amenities.
- Enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources.

Further, with respect to major Federal actions significantly affecting the quality of the human environment, Sect. 102(2)(C) of the NEPA calls for preparation of a detailed statement on:

(i) the environmental impact of the proposed action;

(ii) any adverse environmental effects which cannot be avoided should the proposal be implemented;

(iii) alternatives to the proposed action;

(iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and,

(v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

An environmental report accompanies each application for a construction permit or for a full-power operating license. A public announcement of the availability of the report is made. Any comments by interested persons on the report are considered by the staff. In conducting the required NEPA review, the staff meets with the applicant to discuss items of information in the environmental report, to seek new information from the applicant that might be needed for an adequate assessment, and generally to ensure that the staff has a thorough understanding of the proposed project. In addition, the staff seeks information from other sources that will assist in the evaluation and visits and inspects the project site and surrounding vicinity. Members of the staff may meet with state and local officials who are charged with protecting state and local interests. On the basis of all the foregoing and other such activities or inquiries as are deemed useful and appropriate, the staff makes an independent assessment of the considerations specified in Sect. 102(2)(C) of the NEPA and 10 CFR Part 51.

This evaluation leads to the publication of a draft environmental statement, prepared by the Office of Nuclear Reactor Regulation, which is then circulated to Federal, state, and local governmental agencies for comment. A summary notice of the availability of the applicant's environmental report and the draft environmental statement is published in the Federal Register. Interested persons are also invited to comment on the proposed action and on the draft statement.

After receipt and consideration of comments on the draft statement, the staff prepares a final environmental statement, which includes a discussion of questions and concerns raised by the comments and the disposition thereof; a final benefit-cost analysis, which considers and balances the environmental effects of the facility and the alternatives available for reducing or avoiding adverse environmental effects with the environmental, economic, technical, and other benefits of the facility; and a conclusion as to whether – after the environmental, economic, technical, and other benefits are weighed against environmental costs and after available alternatives have been considered – the action called for, with respect to environmental issues, is the issuance or denial of the proposed permit or license or its appropriate conditioning to protect environmental values. This final environmental statement and the safety evaluation report prepared by the staff are submitted to the Atomic Safety and Licensing Board for its consideration in reaching a decision on matters in controversy regarding the application. The same format as used in the Draft Environmental Statement is used in this Final Statement to facilitate its review.

This environmental review deals with the impact of operation of San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2 & 3). Assessments that are found in this statement supplement or modify those described in the Final Environmental Statement (FES-CP) that was issued in March 1973 in support of issuance of construction permits for the units. The information found in the various sections of this Statement updates the FES-CP in four ways: (1) by identifying differences between environmental effects of operation (including those which would enhance as well as degrade the environment) currently projected and the impacts that were described in the preconstruction review, (2) by reporting the results of studies that had not been completed at the time of issuance of the FES-CP and that were required by the NRC staff to be completed before initiation of the operational review, (3) by evaluating the applicant's preoperational monitoring program and by factoring the results of this program into the design of a postoperational surveillance program and into the development of environmental technical specifications, and (4) by identifying studies being performed by the applicant that will yield additional information relevant to the environmental impacts of operating SONGS 2 & 3.

Copies of this statement are available for inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C.; the Mission Viejo Branch Library, 24851 Chrisanta Drive, Mission Viejo, California; and the NRC Office of Inspection and Enforcement, 1990 N. California Boulevard, Walnut Creek, California. Copies of this statement may be obtained as indicated on the inside front cover. Mr. Dino C. Scaletti is the NRC Project Manager for this statement. Mr. Scaletti may be contacted at (301) 492-8443.

1. INTRODUCTION

1.1 HISTORY

On May 28, 1970, the Southern California Edison Company and the San Diego Gas and Electric Company filed an application with the Atomic Energy Commission (now Nuclear Regulatory Commission) for permits to construct San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2 & 3). Construction Permits Nos. CPPR-97 (Unit 2) and CPPR-98 (Unit 3) were issued on October 18, 1973, following reviews by the AEC regulatory staff and the Commission's Advisory Committee on Reactor Safeguards, as well as a public hearing before an Atomic Safety and Licensing Board in San Diego and San Clemente, California on January 16 to 24, March 13 to 15, and May 14 to 22, 1973. An additional session of the hearing was held in Los Angeles, California on May 19, 20, and 21, 1976. The conclusions reached in the staff's environmental review were issued in a Final Environmental Statement (FES-CP) in March 1973.

As of December 1980, construction of Unit 2 was about 97% complete and construction of Unit 3 was about 68% complete. Each unit has a pressurized-water reactor that will produce up to 3410 MWt and a net electrical output of up to 1106 MWe.

In November 1976 Southern California Edison Company and San Diego Gas and Electric Company submitted an application including a Final Safety Analysis Report (FSAR) and Environmental Report (ER) requesting issuance of operating licenses for Units 2 and 3. These documents were docketed on March 22, 1977, and the operational safety and environmental reviews were initiated at that time.

The City of Anaheim, California, and the City of Riverside, California have recently been added as co-holders of the Construction Permits for San Onofre 2 and 3 and will soon request to be included as applicants for Operating Licenses. The four groups are co-owners of the facility and are referred to herein as the applicant.

1.2 PERMITS AND LICENSES

The applicant has provided a status listing of environmentally related permits, approvals, licenses, etc., which are required from Federal, regional, state, and local agencies in connection with the proposed project (ER, Sect. 12). The staff has reviewed that listing. An amendment to the permit from the California Coastal Commission may be required to obtain approval for the modified exclusion area plan. The staff is not aware of any other potential non-NRC licensing difficulties that would significantly delay or preclude the proposed operation of the plant.

2. THE SITE

2.1 RESUME

The staff visited the SONGS site in May 1977 primarily to determine what changes had occurred at the site and in surrounding areas since the preconstruction environmental review in late 1972. In addition, more detailed information about the operation of SONGS 2 & 3 was obtained as a result of this visit.

Population distribution estimates have been updated and extended to the year 2020. The major land use change has been the construction of the plant itself. Transmission line routes have undergone some changes.

An updated description of the surface-water hydrology is given in Sect. 2.3.1.

The section on meteorology has been revised to include the results of recent observations.

Considerable additional field work and sampling is reflected in the description of terrestrial and aquatic ecology in Sect. 2.5.

2.2 REGIONAL DEMOGRAPHY AND LAND USE

2.2.1 Population change

Population for 1976 by sectors within 80 km (50 miles) of the plant and the projected population estimates to the year 2020 are provided in Tables 2.1-2 through 2.1-15 of the ER. The population within a 16-km (10-mile) radius of the site in 1976 was 57,241. By 1980 this population was expected to increase to 67,547 – an annual growth rate of 4.2% (ER, Sect. 2.1.3.2.1). The major cities in the area and their 1975 populations are San Clemente (20,794), 6.4 km (4 miles) northeast; San Juan Capistrano (13,658), 16.8 km (10.5 miles) northwest; Oceanside (54,900), 27.2 km (17 miles) southeast; and San Diego (1,518,000), 81.6 km (51 miles) southeast. Table 2.1 provides 1976 population data by sector within 16 km (10 miles) of the site.

Table 2.1. Population by sector and distance with 10 miles of San Onofre site (1976)

	Distance (miles)						
Sector	0 to 1	1 to 2	2 to 3	3 to 4	4 to 5	5 to 10	Total 0 to 10
W	0	0	0	0	0	0	0
WNW	0	0	0	0	0	0	0
NW	0	656	54	3532	5298	21,979	31,519
NNW	0	732	630	0	0	6,541	7,903
N	0	0	0	4300	0	519	4,819
NNE	0	0	0	0	0	0	0
NE	0	0	4600	0	0	0	4,600
ENE	0	0	0	0	0	0	0
E	0	0	0	0	4300		4,300
ESE	0	0	0	0	0	3,100	3,100
SE	0	0	0	0	0	1,000	1,000
SSE	0	0	0	0	0	0	0
Total	0	1388	5284	7832	9598	33,139	57,241

Source: ER, Table 2.1-2.

(To convert miles to kilometers, multiply by 1.6.)

Table 2.2 presents projected population and annual growth rates within 16 km (10 miles) of the plant between 1976 and 2020. The total percentage change in population for the area between 1976 and 2020 is projected to be 99.4%. These projections are based on surveys made by the Southern California Association of Governments, the Comprehensive Planning Organization of San Diego County, the California State Department of Finance, and the applicant (ER, Sect. 2.1.3.2.3).

Table 2.2. Projected population and annual growth rate within 16 km of the San Onofre site

Year	Projected population	Annual growth[a] (%)		Change (%)
1976	57,241	4.2		
1980	67,547			
1980	67,547	2.9		
1990	89,521			
1990	89,521	0.3	1.6	99.4
2000	91,949			
2000	91,949	1.0		
2010	101,945			
2010	101,945	1.1		
2020	114,139			

[a]Compounded annually.

Source: Adapted from ER, Table 2.1-8.

2.2.2 Changes in land use

Since issuance of the FES-CP in 1973, the construction of SONGS 2 & 3 is the only major change in land use in the site vicinity. Site preparation required the excavation of 16.39 ha (40.5 acres) of the San Onofre Bluffs, which otherwise could be used primarily for recreation. Most of this material was deposited on 34 ha (84 acres) at Japanese Mesa, a relatively flat area just north and across Interstate 5 from the site on Camp Pendleton Marine Base (ER, Sect. 4.1.2). In addition, about 304.8 m (1000 ft) of beach front has remained closed except as a passageway during the construction period (ER, Appendix 12-B, p. 7).

The area within an 8-km (5-mile) radius of the site occupies parts of two counties. The part of this area that lies in Orange County is entirely within San Clemente. The predominant land use in San Clemente is single family residential, light commercial, and recreational. Industrial land use in San Clemente is limited to light industry only. Because the available developable land is steep, future development in that area is expected to be slow with only low residential densities permitted by the city (ER, Sect. 2.1.4.3.1). In San Diego County, the 8-km (5-mile) radius area lies within Camp Pendleton Marine Base. About 95% of Camp Pendleton is unimproved land that is used for military purposes, recreation, and conservation (FES-CP, Sect. 2.2.2). Figure 2.1-12 of the ER provides a detailed land use map of the area within an 8-km (5-mile) radius of the site.

Heavy-haul components for the plant arrive by barge or by vessel at the Del Mar Boat Basin near Oceanside, about 22.5 km (14 miles) south of the site (ER, Suppl. 2, Item 37). The haul route, which was not available at the time the FES-CP was issued, required that a road be cut through the bluffs between the beach and Highway 101, about 11 km (7 miles) north of the Del Mar Boat Basin (ER, Suppl. 2, Item 37).

The description of the transmission lines as presented in Sect. 3.7 of the FES-CP has been modified (Sect. 3.2.5). No new rights-of-way were required: about 5.2 ha (12.8 acres) will be used for new tower bases and for access-road extensions, and 2 ha (5 acres) of land will be covered by the Talega Substation (ER, Suppl. 2, Item 36). Three changes in land use adjacent to the San Onofre–Santiago transmission line route have occurred since the issuance of the FES-CP: (1) construction of a paved road immediately adjacent to a significant portion of the proposed transmission line, (2) bulldozing of a firebreak adjacent to the transmission line on Camp Pendleton Marine Base, and (3) active operation of a large aggregate borrow site adjacent to the line in a third location (ER, Appendix 6A).

2.2.3 Changes in the local economy

Construction activity peaked in late 1979 with an estimated work force of about 3000. The applicant has estimated, after discussions with officials of the labor unions represented at SONGS 2 & 3, that 20%, or about 600 workers, relocated to the southern California area from other parts of the country (ER, p. S.2-167). Although all union craft workers at the site were hired from unions located within a 96-km (60-mile) radius of the site, all of the workers who relocated were travel card members who were assigned by the local unions to SONGS 2 & 3 after the local list was exhausted. Because the construction workers lived throughout the metropolitan areas of San Diego, Orange County, and Los Angeles, the impact of the workers' income was diffuse.

From 1974 through 1976 the applicant estimated that about $4.1 million was spent within a 48-km (30-mile) radius of the site for materials and services. These expenditures accounted for about 0.2% of the total forecast plant cost (ER, p. S.2-174).

2.3 WATER USE

2.3.1 Surface-water hydrology

The only significant water resource in the vicinity of SONGS is the Pacific Ocean. A few streams are located near the site, but these are intermittent.

The currents in the San Onofre vicinity are a superposition of many effects. This current system can be decomposed into individual components. The two most persistent components are the California Current and the tides.

The California Current is evident close to shore and north of Point Conception. However, south of this point the coastline recedes to the east, and water is available for entrainment from the east side of the current. This entrainment tends to make the California Current more diffuse south of Point Conception. Furthermore, the effect of this entrainment in addition to upwelling, winds, and baroclinic instabilities[1] can produce a counter-rotating eddy through the Channel Islands which is known as the Southern California Eddy; the nearshore northward flowing current is the Southern California Countercurrent. Observations indicate that this eddy can exist year-round; however, it is strongest in the fall and in the early winter.

Tides along the California coast are a mixed type with diurnal and semidiurnal components. The diurnal period lasts about 25 hr, and the semidiurnal period is about half the duration of the diurnal. As a result of tidal rotation, flood tide flows up the coast and ebb tide flows down the coast. A more detailed discussion of the tides in the San Onofre vicinity can be found in Sect. 2.6.3 of the FES-CP.

The total near-shore current is the sum of the large-scale current systems, the tides, and other effects such as local winds and offshore storms. The net result is a highly complex current structure that is quite variable in speed and direction. An additional complication is stratification. During the winter when vertical homogeneity exists, near-shore currents are fairly uniform with depth. However, during the summer the presence of the thermocline divides the water column so that only certain components of the net flow are uniform with depth. These components, such as tides, are driven over the entire water column. Surface driving forces (the wind) will penetrate the epilimnion; however, the thermocline represents a barrier to these stresses reaching the hypolimnion. The wind energy is then concentrated in the epilimnion, resulting in an increased intensity of wind-driven flow which can dominate all other components. In contrast, the hypolimnion is relatively free of wind effects and, therefore, is strongly influenced by the tides. The net result is a two-layered flow regime in which the flow in the two layers is only weakly correlated. This already-complicated flow structure can be altered by large amplitude internal waves. The breaking of these waves provides periodic vertical mixing.

A survey of the currents in the San Onofre area was conducted in 1972 by Intersea Research Corporation.[2] Data from this study have been analyzed by Koh and List.[3] From this analysis the following summary information has been extracted.

1. A net drift current can occur in a number of directions; however, the onshore/offshore component of the drift is necessarily smaller than the longshore component.

2. The longshore component of the drift changes direction every 3 to 6 days with downcoast flow typically having a longer duration.

3. The magnitude of the longshore drift is less than 30 cm/sec (0.6 knot).

4. The onshore/offshore component of drift is less than 15 cm/sec (0.3 knot).

5. An upcoast component of drift usually is associated with an onshore component of drift, and vice versa.

6. Both components of tidal flow are typically 10 cm/sec (0.2 knot).

The most detailed study of natural temperature variations in the San Onofre vicinity is that of Koh and List.[3] This study was based on daily temperature measurements from 1966 through 1970 taken at the ends of piers at Balboa, San Clemente, Oceanside, and La Jolla. These data were separated into three frequency ranges - low, middle, and high. The low-frequency component represents data averaged over two months, and it reflects seasonal variations. After removal of these low frequencies, the data were averaged over one week. This is the middle-frequency band, which represents variation within periods from one week to two months. The residual data, the high-frequency band, represents daily to weekly fluctuations. Figure 2.1 is a plot of temperature vs time for the three frequency bands and the raw data for San Clemente. The temperature ranges from 12.1°C (54°F) to 22.9°C (73°F). The low-frequency curve shows an annual temperature cycle with a maximum in midsummer and a minimum in midwinter.

As part of their analysis, Koh and List performed a correlation study among the temperature records from the various locations. Both the low- and middle-frequency ranges showed very high correlations at zero lag time between Oceanside and San Clemente. This indicates that the mechanisms influencing these frequency components have a length scale greater than the distance between the two sampling locations. Therefore, temperature variations at San Onofre within periods of one week or longer can be represented adequately by the corresponding temperature variations at either San Clemente or Oceanside. The correlation of the high-frequency components between these two stations is very weak, indicating that short-term temperature fluctuations are a spatially localized phenomenon. This fact is substantiated by near-surface-temperature measurements made from a moving boat which show that horizontal temperature variations of 1.1°C (2°F) over 1.6 km (1 mile) are not uncommon off the coast of southern California.[3]

An additional feature of the thermal structure in the San Onofre vicinity is vertical stratification. During the winter this region is, in general, isothermal over the water column. As warming progresses, a vertical temperature gradient is established and reaches a maximum in late summer. This natural gradient has been as much as 0.55°C/m (0.3°F/ft).

Ocean salinity in the San Onofre vicinity shows little spatial variation. An annual salinity cycle does exist as a result of annual cycles in the local meteorology and large-scale current systems. During this cycle, salinity typically ranges from 33 to 34 ppt, with the minimum occurring in winter and the maximum occurring in summer.

2.3.2 Groundwater hydrology

The average elevation of the water table at the beach line is +1.5m (+5 ft) mean lower low-water level (MLLW) with a slope of less than 1%; inland, the gradients range from 2 to 8% toward the ocean. Some groundwater can be obtained from the San Onofre Groundwater Basin, and it is used at Camp Pendleton Marine Base, but it is not a resource used by the Station. The Station obtains its domestic supply of freshwater from the Tri-Cities Municipal Water District.

2.3.3 Water quality

Dissolved oxygen concentration in southern California coastal waters ranges from about 5 to 13 mg/liter. Observations at the site vary from 5.4 to 10.0 mg/liter (2 to 3.6 grains/gal). The pH of southern California surface waters varies from 7.5 to 8.4 with a mean of about 8.0.

Measurements of coliform concentrations at the site were made during the period 1967 to 1975. Most of the measurements gave a mean probable number (MPN) of 4 to 43 colonies/100ml (1 to 13 colonies/oz). Only two measurements exceeded 43, and these occurred in 1972 and both gave a MPN value of 460 (140).

Turbidity in the vicinity of the site is due primarily to the suspension of bottom material in the surf zone. Outside the surf zone, turbidity generally decreases as distance from shore increases. Typical depths of Secchi Disc visibility range from 2 to 5 m (6.5 to 16 ft).[4] The vertical variation of turbidity is often quite complex, with alternating layers of clear and turbid water. Visible plumes of turbidity have been observed occasionally on the ocean surface in the vicinity of the Unit 1 offshore discharge structure. These plumes have been observed and, depending on ambient conditions, are caused by the intake and subsequent discharge of naturally turbid water and the entrainment of naturally turbid water into the discharge stream as it moves towards the surface (ER, Sect. 2.4.3.8.2).

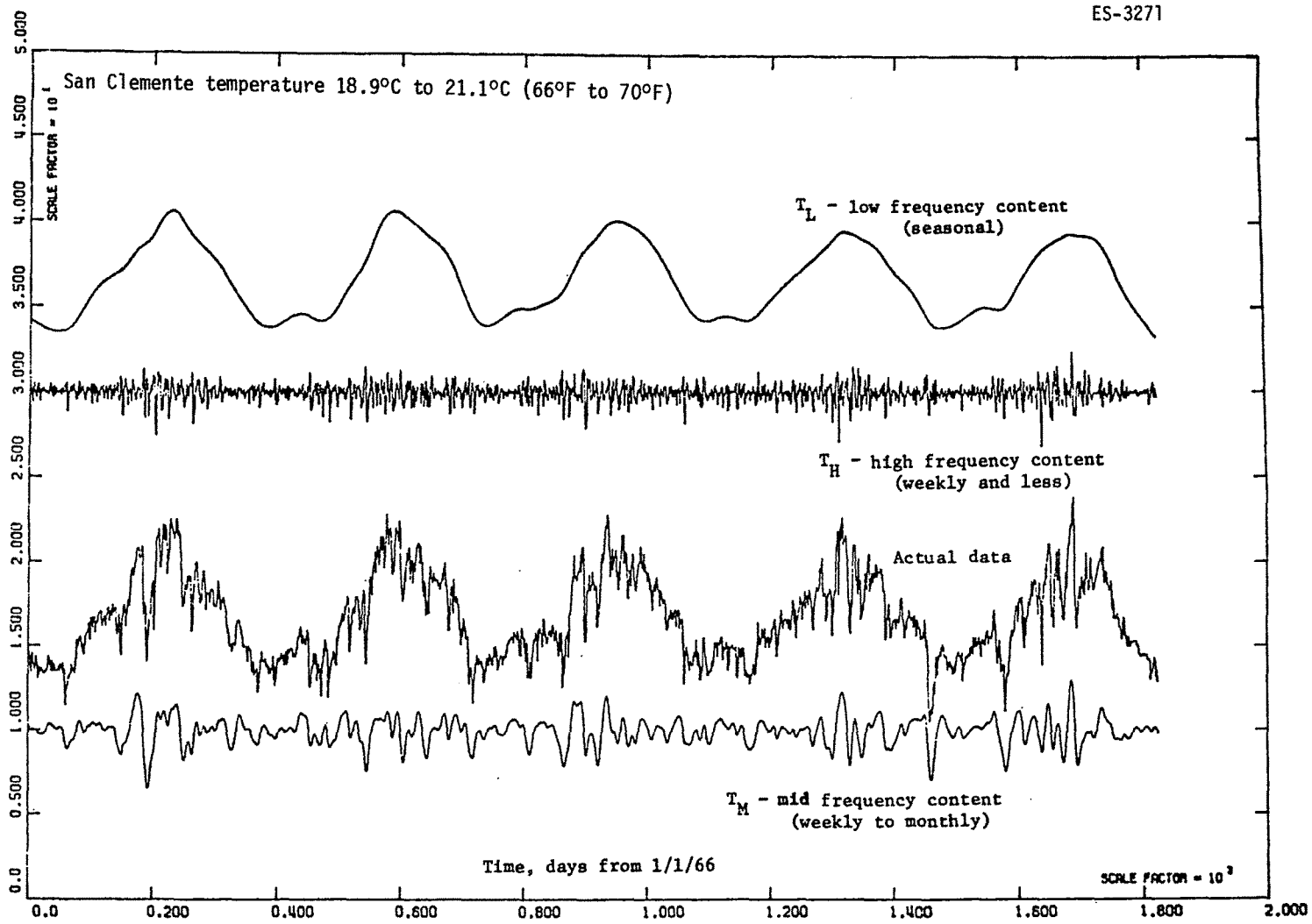

Fig. 2.1. Daily temperatures and decompositions into various frequency bands at San Clemente. Source: R. C. Y. Koh and E. J. List, *Report to Southern California Edison Company on Further Analysis Related to Thermal Discharges at San Onofre Nuclear Generating Station*, Sept. 30, 1974, Fig. 3.2.

2.3.4 Storm runoff

The probable maximum 1-hr thunderstorm rainfall is 17.8 cm (7.0 in). Much of the country to the north and east of the Station site drains into the San Onofre Creek, which flows into the ocean 2 km (1-1/4 miles) northwest of the site. The land immediately east of the site now drains into a 3.7-m-wide (12-ft-wide) ditch that parallels Interstate Highway 5 (I-5) just east of the Station. Both lanes of I-5 also drain into this ditch, which discharges into San Onofre Creek. Storm runoff from the hills above the site drains through one 182-cm-(72-in.-) and one 107-cm-(42-in.-)diam culvert that run north along the highway right-of-way and then turn under the site to the beach. The culverts and channel are designed for the runoff associated with a 1% chance (100-year) storm. To preclude flooding at the site during the occurrence of a probable maximum thunderstorm, an earthen dike will be constructed to the east side of I-5 to divert runoff and debris from the foothills area to San Onofre Creek.

2.4 METEOROLOGY

2.4.1 Regional climatology[5-9]

The climate of the coastal regions of southern California is strongly influenced by the Pacific Ocean. Summers are relatively cool with daytime temperatures averaging only in the low-to-mid-20s (°C) (70°F); daytime seabreezes are frequent. Outbreaks of hot, dry desert air from east of the coastal mountains (Santa Ana winds) may intrude onto the coastal plain several times each year, primarily in the fall, but temperatures exceed 32°C (90°F) usually less than five days annually. The proximity to the Pacific Ocean also results in mild winters, with daytime highs in the upper teens (°C) (60s°F) and nighttime lows around 5 to 10°C (40s°F). Temperatures below freezing are rare.

Precipitation along the coastal plain averages around 250 mm (10 in.) annually. The rainfall is very seasonally dependent with 85% of the total occurring from November through March; almost no rain falls during the summer months. Average relative humidities range from about 80% during the early morning hours of summer and fall, down to around 55% during winter afternoons.

2.4.2 Local meteorology[5,6,8,9]

The San Onofre site is located on the relatively narrow coastal plain, near the mouth of San Onofre Canyon. Coastal bluffs, nearby hills and valleys, and the Pacific Ocean contribute to the complexity of the site topography. Within 8 km (5 miles) of the site, elevations range from 525 m (1725 ft) above sea level [about 5.5 km (3.5 miles) east of the site] to sea level along the Pacific Ocean.

To assess the local meteorological characteristics of the San Onofre site, climatological data from San Diego, California [80 km (50 miles) southeast of the site]; from Los Angeles, California [95 km (60 miles) northwest]; and data collected onsite are available. These data are reasonably representative of the climatological conditions expected in the vicinity of the site.

In the site area, average daily maximum and minimum temperatures range between 25°C (77°F) and 18°C (64°F) in August, the warmest month, and between 18°C (65°F) and 8°C (46°F) in January, the coolest month. The extreme maximum temperature recorded was 44°C (111°F) at San Diego in September 1963; the extreme minimum temperature was -5°C (23°F) at Los Angeles in January 1937.

The area receives about 250 mm (10 in.) of rain annually; December, January, and February — the wettest three-month period — averages about 150 mm (6 in.), and June, July, and August combined averages less than 2.5 mm (0.1 in.). The maximum 24-hr rainfall recorded among these stations is 157 mm (6.2 in.) at Los Angeles in January 1956. Snowfall is a rarity, with a trace [less than 0.25 mm (0.01 in.)] being the most ever recorded. Heavy fogs [visibility of 0.4 km (0.25 mile) or less] occur on about 30 to 40 days each year along the coast with about half of the occurrences during October through January.

Windflow at the site has a strong diurnal dependence primarily due to the land-sea breeze effect. During daytime hours the windflow has a predominant onshore directional component, whereas at night windflow tends toward a seaward direction. Table 2.3 shows the wind direction with the greatest frequency of occurrence for each hour of the day for the three-year period of January 25, 1973, through January 24, 1976, as measured at the 10-m (33-ft) level of the onsite meteorological tower. Figure 2.2 shows the directional frequency of onsite winds. About 25% of the total windflow over the site was from the northeast and north-northeast (principally night-time offshore flow); 19% of the flow occurred from the west and west-northwest (daytime onshore flow). Winds were calm [windspeeds less than 0.34 m/sec (0.75 mph)] less than 1% of the time at the 10-m (33-ft) level.

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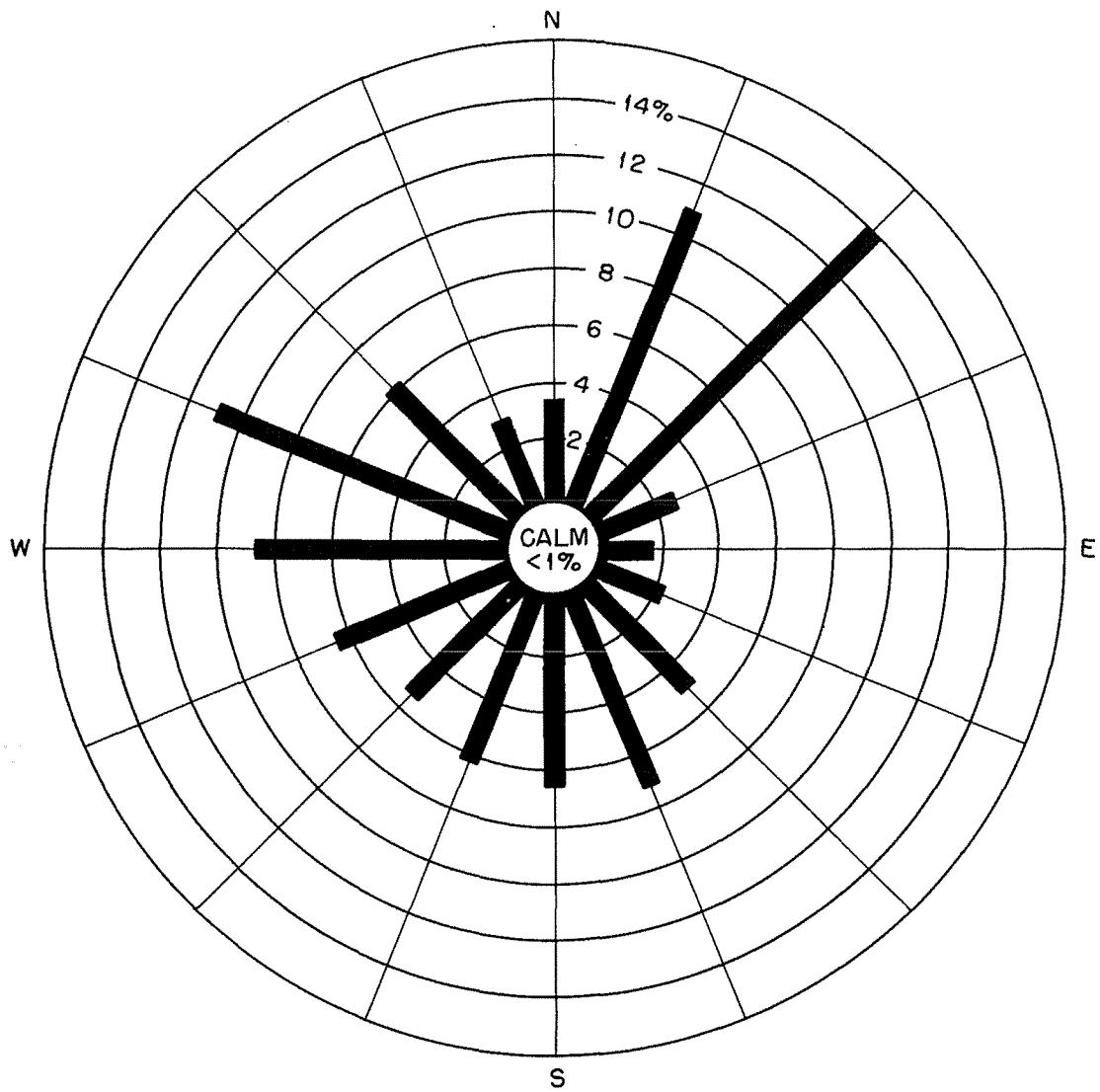

Fig. 2.2. Directional frequency of wind at the San Onofre site. Onsite data at 10 m (33 ft) above ground level, Jan. 25, 1973 through Jan. 24, 1976. Bars show the direction from which the wind blows. Calms are those winds with hourly average speeds less than 0.34 m/sec (0.75 mph).

Table 2.3. Wind direction with greatest frequency of occurrence by time of day at San Onofre Nuclear Generating Station

Data measured at 10-m (33-ft) level of onsite meteorological tower

Hour (AM)	Wind direction	Frequency (%)	Hour (PM)	Wind direction	Frequency (%)
1	NE	28	1	WNW	25
2	NE	26	2	WNW	27
3	NE	27	3	WNW	27
4	NE	28	4	WNW	27
5	NE	30	5	WNW	22
6	NE	30	6	WNW	16
7	NE	25	7	NW	14
8	NE	19	8	NE	13
9	S	12	9	NE	16
10	W	17	10	NE	20
11	W	20	11	NE	23
Noon	WNW	22	Midnight	NE	25

2.4.3 Severe weather[5-13]

Although infrequent, thunderstorms, tornadoes, tropical cyclones, and dust storms can affect the site area. Thunderstorms occur less than 5 days annually. Tropical storms are also rare in the site area, with a storm entering the region less than once every 10 years. The "fastest mile" of wind recorded at Los Angeles was 28 m/sec (62 mph) (March 1952). Snow, glaze, and hail are almost nonexistent in the site vicinity.

Between 1952 and 1975, 23 tornadoes and 21 waterspouts were reported within a 34,000-km^2 (13,000-mi^2) area containing the site. Staff analysis of these tornado data indicates that the mean path area of a tornado in this region is about 0.3 km^2 (0.1 mi^2). Using the methods of Thom, this results in a recurrence interval of 70,000 years for a tornado or waterspout at the plant site.

Dust storms are relatively infrequent within the site region; between 1940 and 1970, dust or blowing dust and sand reduced visibility to under 11 km (7 miles) about 1 hr annually. About 8 days each year there is a high meteorological potential for air pollution.

2.4.4 Atmospheric dispersion[5,6,14,15]

Southern California Edison Company (SCE) has provided joint frequency distributions of wind speed and direction by atmospheric stability class, based on the vertical temperature gradient, collected onsite during the period January 25, 1973 to January 25, 1976. The distributions were for wind speed and direction measured at both the 10- and 40-m (33- and 131-ft) levels with the vertical temperature difference between the 6.1- and 36.6-m (20- and 120-ft) levels. SCE has also conducted a tracer test program to assess the atmospheric dispersion in the landward directions at the San Onofre site. Section 6.2.5 describes the onsite meteorological program and the tracer test program.

The staff has made reasonable estimates of average atmospheric dispersion conditions for SONGS 2 & 3 using an atmospheric dispersion model for long-term releases; this model is based on the "Straight-Line Trajectory Model" described in Regulatory Guide 1.111. The onsite tracer tests showed that ground-level relative concentrations normalized by windspeed were similar whether the source of release was elevated or ground level; thus it was assumed that all plant releases were from ground level. The calculations also include considerations of intermittent releases during more adverse atmospheric dispersion conditions than indicated by an annual average calculation as a function of total duration of release. The calculations include an estimate based on the criteria outlined in Regulatory Guide 1.111 of maximum increase in calculated relative concentration and deposition due to the spatial and temporal variation of the airflow not considered in the straight-line trajectory model. Radioactive decay of effluents and depletion of the effluent plume were also considered as described in Regulatory Guide 1.111.

In the evaluation, we used meteorological data collected onsite between January 25, 1973 and January 24, 1976. All releases were evaluated using joint frequency distributions of wind speed and direction measured at the 10-m (33-ft) level by atmospheric stability [defined by the temperature difference between the 36.6- and 6.1-m (120- and 20-ft) levels]. Data recovery for this time period was 88%.

Table 5.1 presents the calculated values of relative concentration (χ/Q) and relative deposition (D/Q) for specific points of interest.

2.5 SITE ECOLOGY

2.5.1 Terrestrial ecology

The FES-CP describes the terrestrial ecology of the San Onofre site (FES-CP, Sect. 2.8.1). Field work for this description, however, was conducted only during November 1971 and contained very little quantitative data. Consequently, the issuance of the construction permit was subject to the applicant's expansion of its current environmental monitoring program "to determine environmental effects which may occur as a result of site preparation and construction of Units 2 and 3, and to establish an adequate preoperational baseline by which the operational effects of Units 2 and 3 may be judged" (FES-CP, p. iv). In response, the applicant conducted terrestrial ecological studies for a period of 1 year on a 0.61-ha (1.5-acre) quadrat located immediately south of Units 2 and 3 construction site (ER, Appendix 2A). This monitoring program documented seasonal changes in the biotic communities over a 1-year time span and fulfilled the recommendations of NRC Regulatory Guide 4.11.

About 80% of the study area is in a natural plant community of coastal sage scrub, and the remaining 20% has been disturbed by man-related activities. Total cover on the study area ranged from 81 to 98%. The greatest cover was found in February, decreasing toward midsummer. Vegetative diversity in the coastal sage scrub community was relatively low; California sagebrush (*Artemesia californica*) was the dominant species (65% relative cover). Coyote bush (*Baccharis pilularis*) ranked second in the study area (9% relative cover) but had higher relative cover in the disturbed areas than in the climax stand. The applicant's survey suggests that surface disturbances significantly alter the composition of the coastal sage scrub community by encouraging the invasion of exotic perennial and annual plant species, especially mustards and grasses. Establishment of these plants occurred only in areas that have been disturbed (ER, Appendix 2A). As expected for this very small study area (0.61 ha), no endangered plant species were observed.

Fauna observed within the study area included 5 species of reptiles, 12 species of mammals, and 36 species of birds; no amphibians were sighted. None of the species observed in the study area are threatened or endangered as defined by the U.S. Department of the Interior[16] (ER, Sect. 2.2.1.2).

The endangered animal species[16] whose ranges include the vicinity of the plant and associated transmission lines are listed in Table 2.4. Two of these species have been observed by the applicant. The California brown pelican has occurred several times on the beach adjacent to the construction area (ER, Sect. 2.2.1.2), and the California least tern has a nesting colony located near the Del Mar Boat Basin, a facility used by the applicant to move heavy components (see Sect. 2.2.2).

Examination of the geographical distributions[17,18] of the 266 endangered plant species in California[19] indicates that 26 of these species occur in those counties (Orange and/or San Diego) traversed by the transmission lines (Table 2.5). No endangered plant species, however, were observed during the applicant's biological study of the San Onofre-Santiago transmission line route.[20] Biological surveys of the other transmission line routes have not been conducted, but no habitats adjacent to or within the transmission line right-of-way have been classified by state or Federal authorities as being critical to any endangered species (ER, Suppl. 1, Item 22).

2.5.2 Aquatic ecology

The aquatic ecology of the site was described in the FES-CP issued in March 1973, and was based on descriptive data obtained from literature concerning the southern California coast. The FES-CP site description contained minimal baseline information on spatial and temporal differences in species occurrences and population densities. The data obtained since issuance of the FES-CP is primarily from three sources: (1) a thermal effects study performed jointly by Environmental Quality Analysts, Inc., and Marine Biological Consultants, Inc., in 1973 using data and results obtained from 1964-72 by Bendix Marine Advisers, Inc., and Intersea Research Corporation.[21] (2) the SONGS 1 Environmental Technical Specifications (ETS) monitoring program begun in November 1974, conducted by the Lockheed Aircraft Service Company's Department of Marine biology,[22-27]

Table 2.4. Endangered animal species[a] whose ranges include Orange and San Diego counties, California

Common name	Scientific name	Habitat	Reason for decline
California brown pelican	*Pelecanus occidentalis californicus*	Pacific coast from Canada to Mexico	Egg shell thinning due to pollutants such as DDT
California least tern	*Sterna albifrons brownii*	Pacific coast from S. San Francisco Bay, California, to S. Baja, California	Loss of nesting habitat (sandy beaches) due to increased human activity
American peregrine falcon	*Falco peregrinus anatum*	Coast and higher mountains inland	Egg shell thinning due to DDT; human disturbance
Southern bald eagle	*Haliaeetus leucocephalus leucocephalus*	Estuarine areas and inland around large lakes, reservoirs, and wetlands	Disturbance of nesting birds; illegal shooting; loss of nest trees; contamination of food chain by persistent pesticides
Light-footed clapper rail	*Rallus longirostris levipes*	Coastal salt marshes	Destruction of its natural habitat by filling for housing and industrial use, marine development, and water pollution destroying food species and/or habitat

[a]U.S. Department of the Interior, "Endangered and Threatened Wildlife and Plants," 41 F.R. 47180–47198.

Table 2.5. Endangered plant species of Orange and San Diego counties, California

Plant name[a]		Habitat and geography[a]
Scientific	Vernacular	
Acanthomintha ilicifolia	San Diego thornmint	Clay depressions on mesas and slopes; coastal sage scrub, chaparral; SW San Diego County
Arctostaphylos glandulosa var. *crassifolia*	Thickleaf manzantia	Sandy mesas and bluffs; chaparral; coast of San Diego County
Aster chilensis		Dry banks, grassy fields, etc., sea level to 5000 ft; many plant communities; mountains of San Diego County to Santa Barbara County
Astragalus tener titi	Coastal dunes rattleweed	Sandy places near the coast; coastal strand; near San Diego
Berberis nevinii	Nevin's bayberry	Sandy and gravelly places below 2000 ft; coastal sage scrub, chaparral; San Diego County
Brodiaea filifolia	Thread-leaved brodiaea	Heavy clay soil below 2000 ft; coastal sage scrub, chaparral; San Diego County
Brodiaea orcuttii	Orcutt's brodiaea	Near streams and around vernal pools and seeps, up to 5500 ft; chaparral; Yellow Pine Forest, San Diego County
Chorizanthe orcuttiana	Orcutt's chorizanthe	Sandy places; coastal sage scrub; San Diego County
Cordylanthus maritimus ssp. *maritimus*	Salt marsh bird's beak	Coastal salt marsh; Lower California to Oregon
Dicentra ochroleuca	Yellow dicentra	Occasional in dry disturbed places below 3000 ft; chaparral; Santa Ana and Santa Ynez mountains
Dichonda occidentalis	Western dichondra	Mostly dry sandy banks in brush or under trees; coastal sage scrub, chaparral, southern oak woodland; coastal San Diego and Orange counties
Dudleya multicaulis	Many-stemmed dudleya	Dry stony places below 2000 ft; coastal sage scrub, chaparral; San Onofre Mountain, Orange and San Diego counties
Dudleya stolonifera	Laguna Beach dudleya	Cliffs in coastal sage scrub; canyons near Laguna Beach, Orange County
Eryngium aristulatum var. *parishii*	San Diego coyote-thistle	Vernal pools; chaparral; San Diego region
Ferocactus viridescens	San Diego barrel cactus	Dry hills; coastal sage scrub, valley grassland; around San Diego, NW Lower California
Galium angustifolium ssp. *borregoense*		Creosote bush scrub; Borrego Valley, E. San Diego County
Githopsis filicaulis (last reported in 1884)	Mission Canyon blue-cup	Mission Canyon, San Diego
Hemizonia conjugans	Otay tarweed	Mesas; coastal sage scrub; SW San Diego County
Hemizonia floribunda	Tecate tarweed	Dry slopes and valleys below 3500 ft; coastal sage scrub, chaparral; S. San Diego County, N. Lower California
Limnathes gracilis var. *parishii*	Parish slender meadow-foam	Moist lake shores and wet places from 4500 to 5000 ft; Yellow Pine Forest; Cuyamaca and Laguna mountains
Monardella linoides ssp. *viminea*		Rocky washes below 1000 ft; coastal sage scrub, chaparral; SW San Diego County
Monardella macrantha var. *halli*	Hall's monardella	San Gabriel and San Bernardino mountains to Cuyamaca and Santa Ana mountains
Nolina interrata	San Diego nolina	Dry slope; chaparral; W. of Dehesa School, 8 miles east of El Cajon, San Diego County
Orcuttia californica var. *californica*	California orcuttia	Drying mud flats; valley grassland; San Diego County
Poa atropurpurea	San Bernardino bluegrass	Meadows and grassy slopes from 6000 to 7000 ft; Montane Coniferous Forest; San Diego County
Pogogyne abramsii	San Diego pogogyne	Beds of dried pools; chaparral, coastal sage scrub; mesas from San Diego to Miramar

[a] Nomenclature, habitat, and geography from P. A. Munz, *A Flora of Southern California*, University of California Press, Berkeley, Calif., 1974; and W. R. Powell, Ed., *Inventory of Rare and Endangered Vascular Plants of California*, Special Publication No. 1, Berkeley, Calif., 1974.

Source: U.S. Department of the Interior, "Endangered and Threatened Species, Plants," 41 F.R. 24542–24572.

(To convert ft to m, multiply by 0.3048.)

and (3) the Annual Report to the California Coastal Commission, August 1976-1977, by the Marine Review Committee,[28] a special study group established by the California Coastal Commission to estimate the consequences of operating SONGS 2 & 3. Because the ETS program contains the most recent data, included seasonal fluctuations in species occurrences and population densities, and evaluated the effects of SONGS 1 operation on the local marine environment, the description of the site aquatic ecology that follows is based on these data (obtained from November 1974 through December 1976). SONGS 2 & 3 are adjacent to SONGS 1, on the same site. Additionally, the effects of SONGS 1 operation are now a part of the environment of SONGS 2 & 3 and should therefore be included in a complete description of the site ecology.

The biotic communities relevant to an adequate description of the site ecology are the plankton, nekton, benthic, kelp, and intertidal communities.

2.5.2.1 Plankton

Bimonthly plankton sampling was conducted four times in 1975 and six times in 1976 at seven stations along the 10-m (33-ft) contour from 2.4 km (1.5 miles) upcoast to 6.7 km (4.2 miles) downcoast of the SONGS 1 intake/ discharge line (Fig. 2.3).

Phytoplankton

1975 Data. The 84 phytoplankton taxa recorded in the 1975 surveys are similar to those found in previous studies.[25] The phytoplankton was dominated numerically by dinoflagellates. *Prorocentrum micans* was the most abundant species, constituting 30 to 90% of the samples.[22] Other abundant organisms included *Prorocentrum* spp., *Ceratium* sp. A, and *Ceratium* sp. B. Several species of *Peridinium* and *Dinophysis* were also present. The number of taxa per station within each survey was relatively uniform. A complete list of phytoplankton taxa recorded during 1975 is given by station and survey in Appendix VIII, Table 2, p. 217 of ref. 25.

Chlorophyll α concentrations ranged from 0.24 to 2.32 mg/m^3 (0.004 to 0.04 grains/250,000 gal) during the four 1975 surveys.[25] Differences in chlorophyll α concentrations between stations were not significant. Differences were significant, however, between depths and between surveys; chlorophyll α concentrations were significantly greater at the 8-m (26-ft) depth, and the mean concentrations of September were significantly greater than those of the other survey months - May, July, and November.

Phaeopigment concentrations ranged from 0.08 to 1.23 mg/m^3 (0.076 to 0.174 grains/250,000 gal) during the four 1975 surveys.[25] Station differences were not significant, but differences in mean concentrations between surveys and between depths were significant. As with chlorophyll α, phaeopigment concentrations were greater at 8 m (26 ft) than at 1 m (3.3 ft), and the September survey showed the highest phaeopigment concentrations of all four surveys.

1976 Data. In 1976, 128 species or higher taxa of phytoplankton were reported from the six surveys conducted (Table II-2, pp. 11-13 of ref. 26). These taxa consisted of species when identifiable and higher taxa (genera, families, etc.) when identification to the species level could not be made. The taxa representing greater than 30% of any given sample by number were *Nitzschia* spp. (March and November), an unidentified pennate diatom (January, March, July, September, and November), *Gonyaulax* spp. (January and March), and *Prorocentrum micans* (May).[27]

Normal vertical distribution patterns were observed in 1976, as in 1975, with higher concentrations of chlorophyll α and phaeopigments again measured in the lower half of the 10-m (33 ft) water column. However, relatively high values of chlorophyll α were found during the January and May surveys in 1976, whereas in 1975, chlorophyll α concentrations were moderate in May and high in September. Also in contrast to 1975, there was no consistent vertical separation of diatoms from dinoflagellates.

Slightly higher surface temperatures at plankton stations nearest SONGS 1 during some surveys had no apparent effect on the distribution and abundance of phytoplankton; rather, distribution and abundance were apparently the result of natural spatial and temporal variation.[27]

Zooplankton

1975 Data. Zooplankton species encountered in the four 1975 surveys were common to the neritic waters of southern California.[22] A master species list of zooplankton found in the surveys is presented in Appendix VIII, Table 2, p. VIII-30 of ref. 22. The most common group consisted of copepodids of *Acartia* spp., usually accounting for more than 50% of the total number of individuals sampled.[22] Other species that commonly occurred in the samples were *Paracalanus parvus* copepodids, *Oikopleura* spp., *Evadne nordmanni*, *Labidocera trispinosa* copepodids,

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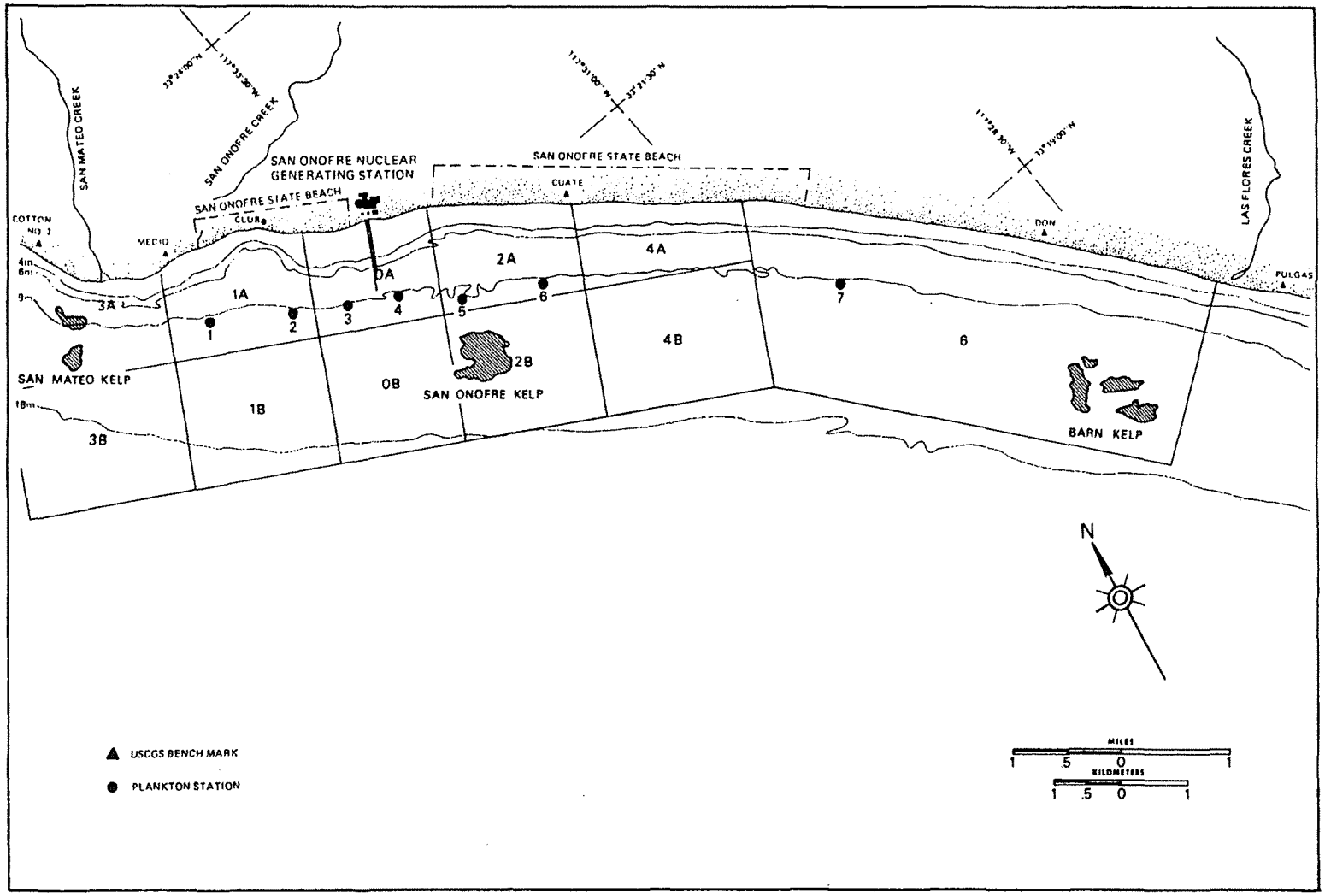

Fig. 2.3. Environmental Technical Specifications plankton station locations and environmental surveillance zones, San Onofre Nuclear Generating Station Unit 1. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

Sagitta euneritica, and Acartia tonsa. Less abundant species were adult Paracalanus parvus, cyphonautes larvae, Acartia clausi, and Clausocalanus spp. copepodids. Other species present usually accounted for less than 1% of any sample.[22]

Sampling stations were best differentiated by the distribution of five species: Sagitta euneritica, Corycaeus amazonicus, Oithona spp. copepodites, euphausiid larvae, and Podon polyphemoides. A clear separation of the stations, however, was not obtained, which suggests that no strong processes in the area acted to partition the environment.[25]

Total abundance per sampling station ranged from 600 to 10,900 per m^3 (568 to 10,322 per 250,000 gal) (Fig. 2.4), and total number of taxa ranged from 36 to 65 during the four surveys of 1975.[25] The number of taxa at station 4 near the SONGS 1 discharge was significantly higher than at all the other stations (Fig. 2.4).

1976 Data. In 1976, 115 species or higher taxa were reported from the six surveys performed (Table II-2, pp. 7-10 of ref. 26). Sixteen taxa were considered predominant because they were numerically dominant (number one in rank) during at least one survey, or because they represented more than 1% of the total number of individuals during the year.[27] These sixteen taxa constituted 90% of the total individuals recorded for the year.[27] The seasonal distribution of each of these taxa during the 1976 surveys is shown in Fig. 2.5. Significant differences were found among stations for all but five of the taxa, and significant differences were found between depths for all but six of them. All of these taxa exhibited significant differences among surveys.

Normal vertical distribution patterns were also observed in 1976, as in 1975, with higher concentrations of zooplankton observed in the lower half of the 10-m (33-ft) water column.

Although higher concentrations of zooplankton were measured near SONGS 1 in 1975, no effect of SONGS 1 was indicated by the 1976 studies. Even though water temperatures during the 1976 November survey (when SONGS 1 was off-line) were unusually warm for the season, the distribution and abundance of zooplankton, as with the phytoplankton, were apparently the result of natural spatial and temporal variation.[27]

2.5.2.2 Nekton

1975 Data

Quarterly nekton sampling was conducted in 1975 at six stations – three stations in the area of the SONGS 1 discharge (zone OA) and three stations about 6706 m (22,000 ft) downcoast (zone 6) (Fig. 2.6). The downcoast stations (zone 6) acted as control areas not under the influence of the SONGS 1 discharge.

A total of 3206 individuals representing 49 species or higher taxa were taken during the four 1975 surveys.[25] The most abundant fish was the queenfish (Seriphus politus), which accounted for nearly twice the number of individuals in the year's catch than the second most abundant species. Other abundant fish were the walleye surfperch (Hyperprosopon argenteum), white croaker (Genyonemus lineatus), spotfin croaker (Roncador stearnsii), jacksmelt (Atherinopsis californiensis), and white surfperch (Phanerodon furcatus). Fourteen species were both abundant and common. Five of the 14 species displayed significant differences in their distributions between zones; four of these – jacksmelt, white seabass (Cynoscion nobilis), white croaker, and queenfish - were significantly more abundant in zone OA, and the pile surfperch (Damalichthys vacca) was more abundant in zone 6.

The variability observed in abundance between zones was influenced significantly by the distribution of four species: white seabass, white croaker, white surfperch, and California corbina (Menticirrhus undulatus). The white seabass and white croaker were significantly more numerous in zone OA, and the California corbina and white surfperch were significantly more numerous in zone 6.

The number of individuals and number of taxa also varied significantly among surveys. However, the degree of similarity of species composition within zones did not differ significantly from the degree of similarity between zones.

1976 Data

A taxonomic summary of the 1976 nekton sampling data by station and by survey can be found in Table III-4, pp. 17-18 of ref. 26. A total of 46 species was reported from these surveys. Seven species – queenfish, white croaker, white surfperch, walleye

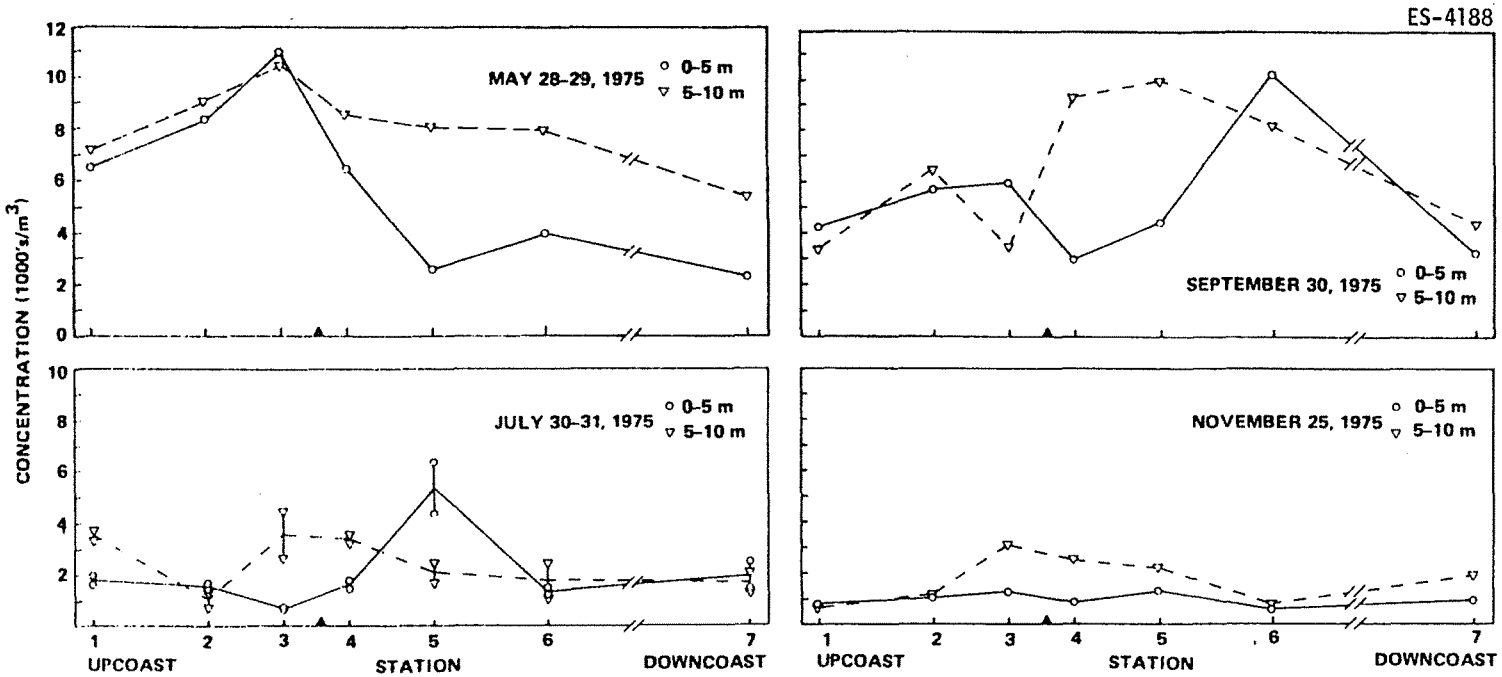

Fig. 2.4. Zooplankton concentrations from 1975 surveys. Open circles (o) and triangles (▽) indicate values from the upper and lower strata respectively. The relative distances of the plankton stations from SONGS 1 are shown. A solid triangle (▲) indicates the position of SONGS 1. A vertical bar connects the July replicates. Source: Lockheed Marine Biological Laboratory, *San Onofre Nuclear Generating Station Unit 1, Annual Analysis Report, Environmental Technical Specifications, January-December 1975*, 1976.

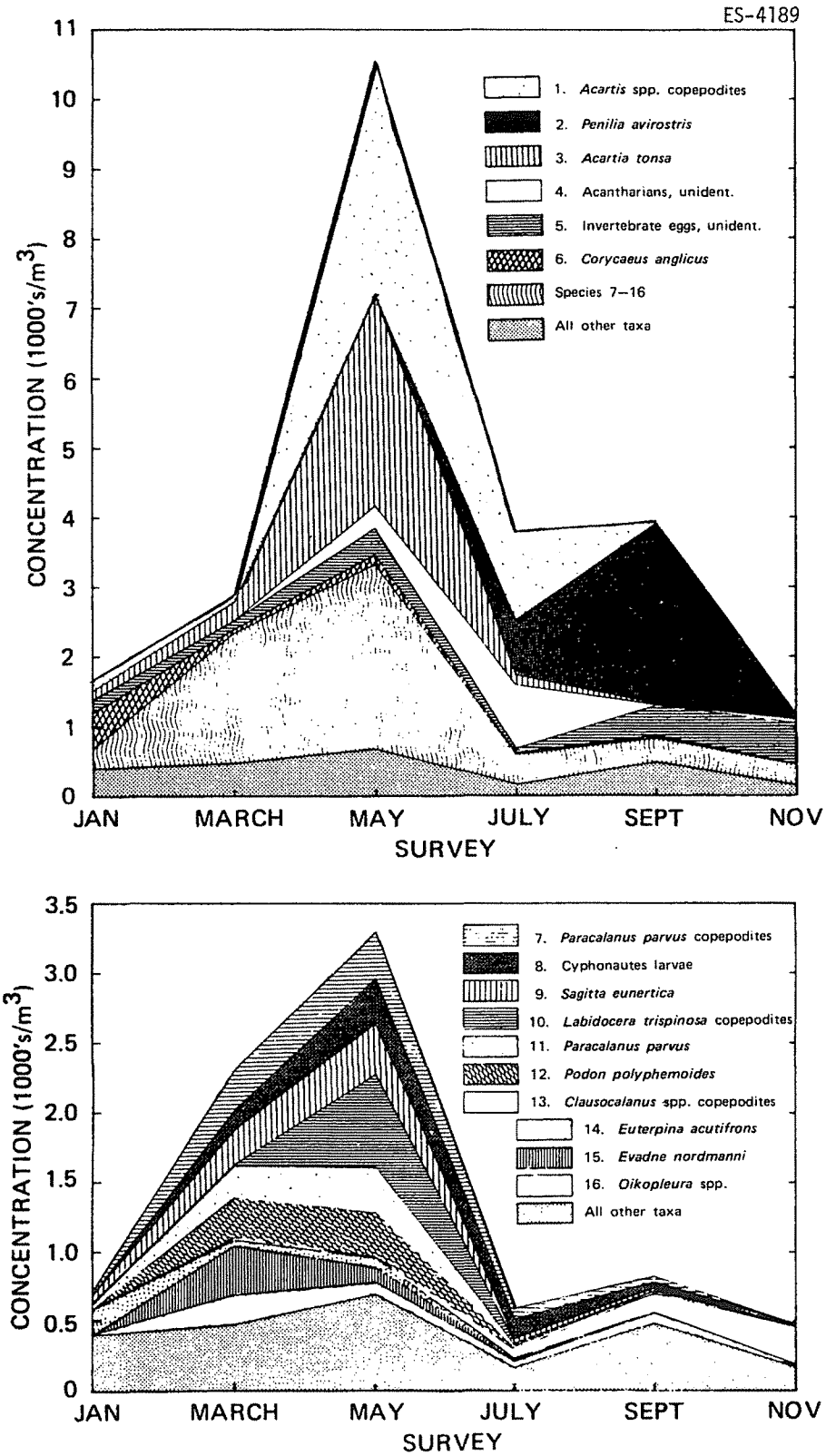

Fig. 2.5. Seasonal distribution of the 16 most abundant zooplankton taxa in 1976. Means of abundance during each survey are plotted. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis – 1976*, June 1977.

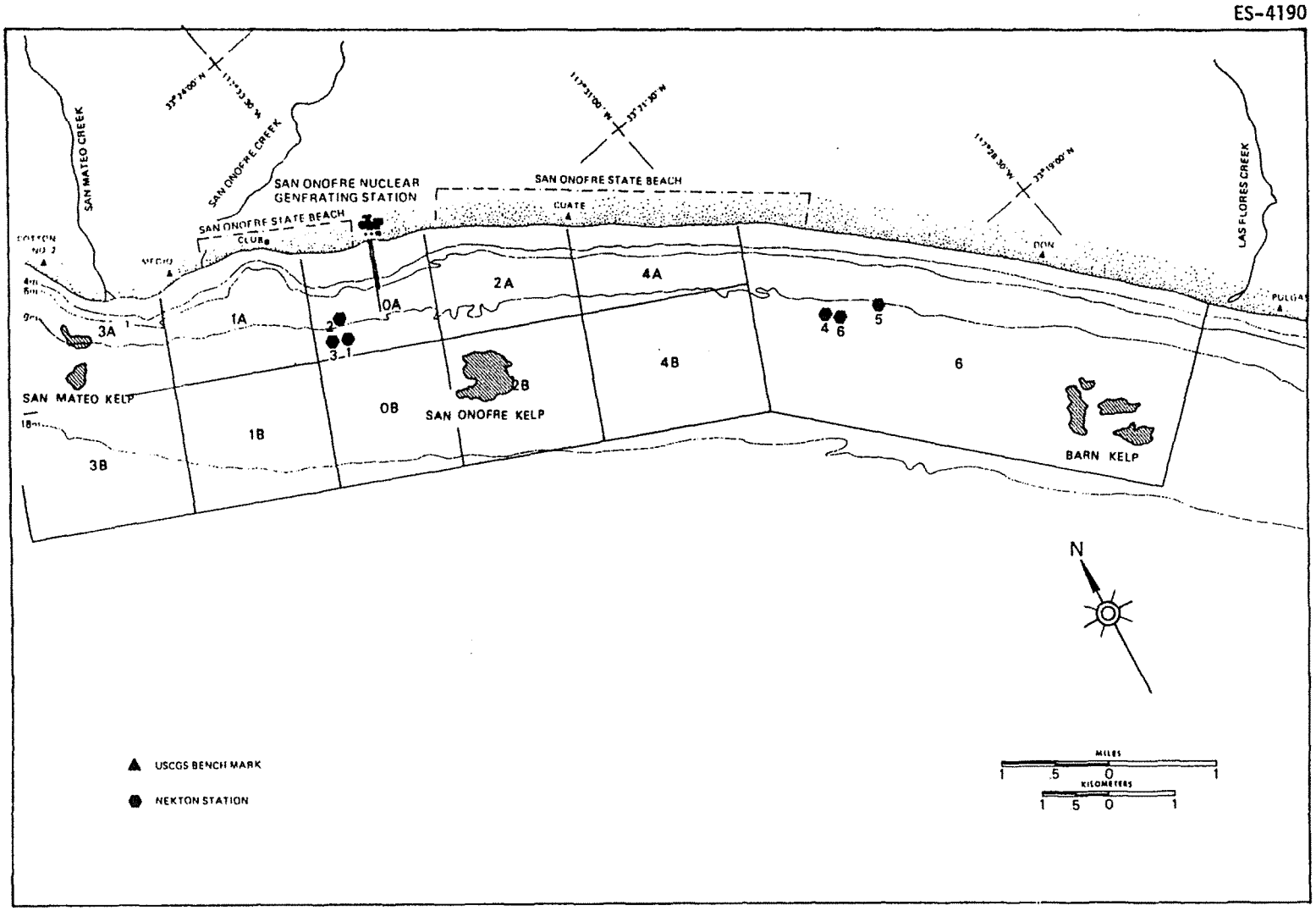

Fig. 2.6. Environmental Technical Specifications nekton station locations and environmental surveillance zones, San Onofre Nuclear Generating Station Unit 1. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

surfperch, black croaker (Chilotrema saturnum), spotfin croaker, and half moon (Medialuna californiensis) were captured in both zones.[27] As a group, these seven species accounted for 81.3% of the total catch for the year.[27] The first five of these species were tested for significant differences between zones and among surveys. Only the queenfish and white croaker showed a significant difference between zones, being significantly more abundant in zone OA than in zone 6. The remaining three species did not differ significantly between zones.

In contrast, six predominant species in 1975 (bottom nets) contributed 82.3% of the individuals collected.[25] Of the predominant species netted in both years, only the queenfish and white croaker were significantly more abundant in zone OA than in zone 6 during both years of the survey.

The spatial distribution of the queenfish, white croaker, and white surfperch differed significantly among the 1976 surveys. Temporally, the queenfish was found to be most abundant during the December survey and least abundant during the March survey. The white croaker was significantly more abundant during the December and March surveys than during the September and June surveys, and the white surfperch was significantly more abundant in the December catch than during all of the other 1976 surveys.

Significant differences were observed in the number of species between zones, with the number in zone OA being significantly greater than the number in zone 6. Four species best discriminated between zones OA and 6: white seabass, white croaker, yellowfin croaker (Umbrina roncador); and white surfperch.

There was also a significant difference among survey periods, with the number of species taken in March being significantly less than the number taken during all of the other surveys, which were not significantly different from each other.

The significant difference found in both number of individuals and number of species among surveys in 1976 was also found in 1975 although no obvious trend in species diversity was revealed (Fig. 2.7). On the other hand, a high similarity within zones existed during 1976; the 1975 data indicated similar but less distinct patterns.

The data suggest that the areas sampled in the two zones may support somewhat different nekton communities. Physical differences between the zones which may also affect the nekton results include the presence of the intake and discharge structures at SONGS 1 and riprap material in zone OA, general differences in substrate type and composition between the zones, turbidity, and the presence of a dense stand of the phaeophyte Cystoseria spp. in the area of the zone OA nekton stations. Temperature data collected during bimonthly cruises and nekton surveys revealed no obvious differences between zones, which indicates that temperature is not an important factor.

Fisheries statistics

Commercial and sport fisheries catch data for 1974 from the California Department of Fish and Game statistical blocks in the vicinity of SONGS 1 (Fig. 2.8) revealed that the number of fish per block ranged from 16,601 in block 737 to 123,246 in block 756.[27] With the exception of block 801, all of the blocks examined measured an increase in catch per unit effort between 1973 and 1974. However, the magnitude of the increase was small in comparison to the decrease shown by all of the blocks over the past 13 years.

The 1974 commercial catch reported a total of 46 taxa from the five blocks surrounding San Onofre.[27] The only taxon common to all five blocks was the Pacific bonito (Sarda chiliensis). Each of the five blocks yielded catches at about the expected level, based on the size of the blocks and the amount of coastline encompassed.[27]

2.5.2.3 Benthos

1975 Data

Three surveys conducted in 1975 at 11 benthic stations (Fig. 2.9) revealed a total of 160 species or higher taxa of epibenthic macrobiota (Tables X-1 to X-11, pp. X-12 to X-43 of ref. 22). The taxa represented members of 11 major taxonomic groups. Within zones not associated with kelp beds (zones OA and 6), the flora was dominated by rhodophyte taxa throughout the year. Mollusks were the dominant fauna during April and October, whereas molluscan and chordate taxa occurred in similar numbers during the July sampling period. Rhodophytes were also the dominant floral component and mollusks were the dominant faunal component of the kelp bed biota at all kelp bed stations during all survey periods.

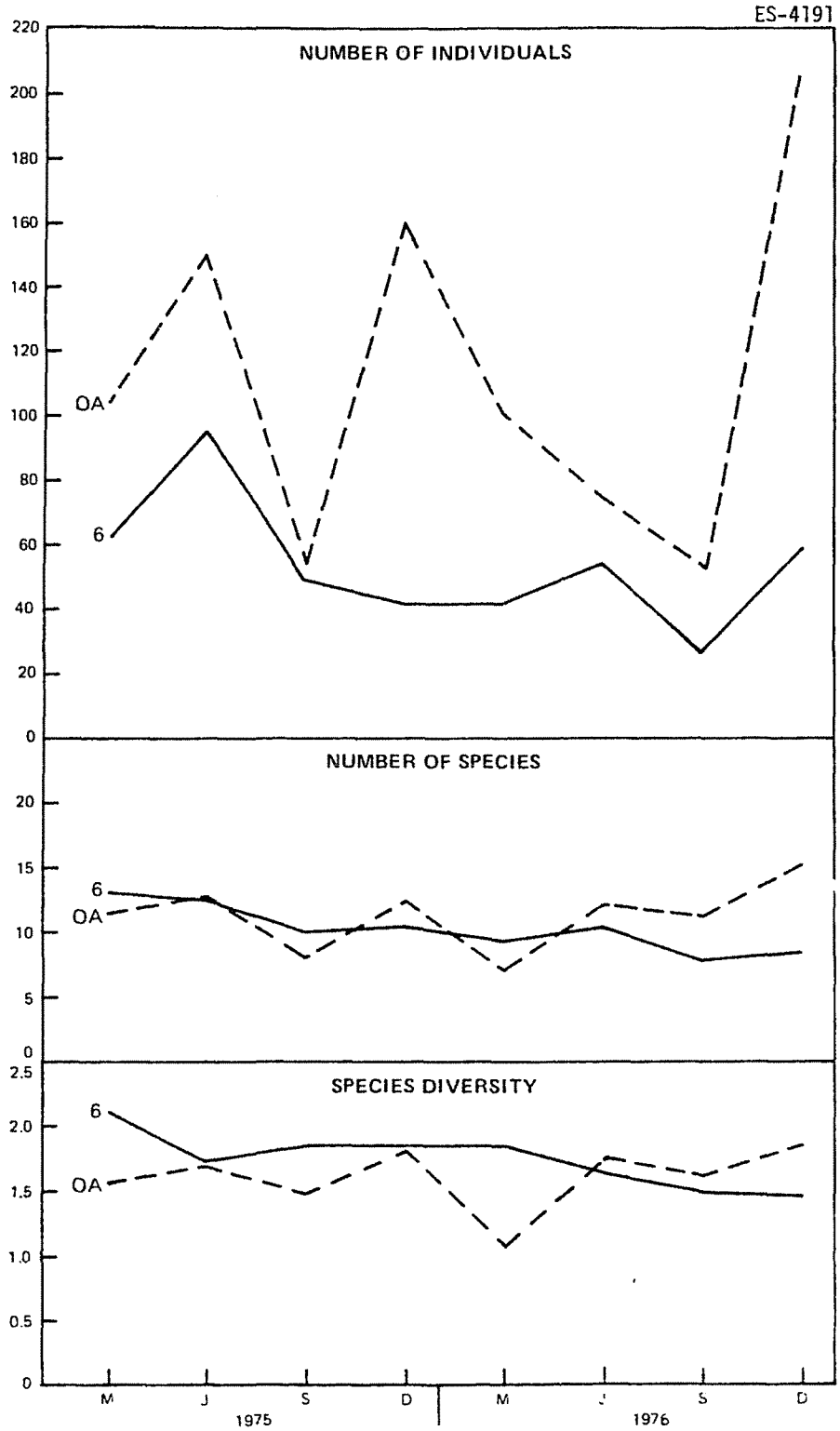

Fig. 2.7. The mean number of individuals and species per net by zone and species diversity of zones OA and 6 by survey during 1975 and 1976. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

The species whose distribution best discriminated between zones OA and 6 were the anthozoan Muricea californica, which occurred mostly in zone 6; the rhodophyte Prionitis spp., which was absent from zone 6; the holothuroid Parastichopus parvimensis, which occurred only in zone 6; and the gastropod Astrea undosa, which was observed only in zone OA.

The trophic composition based on the number of taxa of the two zones not associated with kelp beds (zones OA and 6) was similar among these zones and was dominated by suspension feeders and by primary producers during all surveys (Table 2.6).

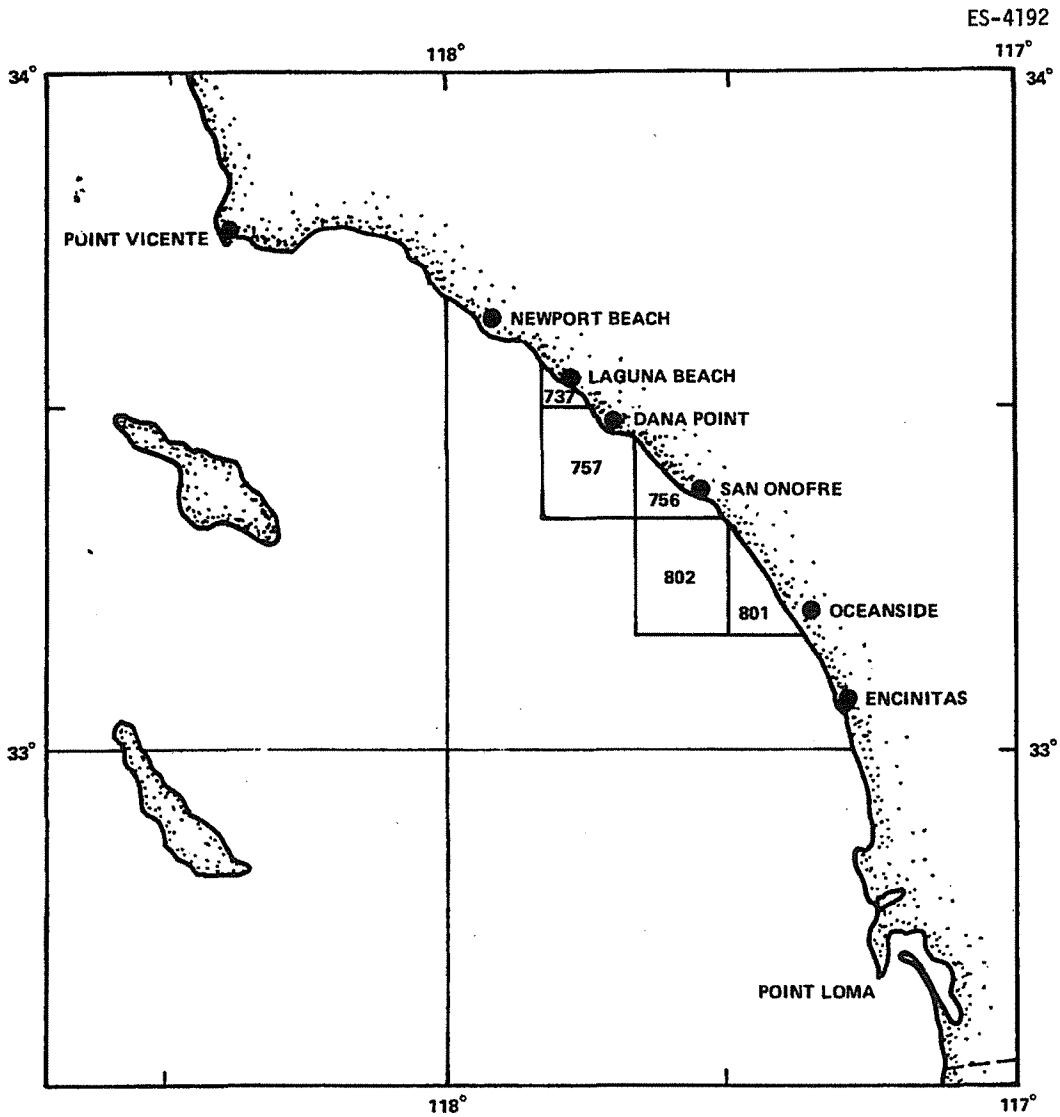

Fig. 2.8. California Department of Fish and Game catch statistic blocks in the vicinity of San Onofre. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis – 1976*, June 1977.

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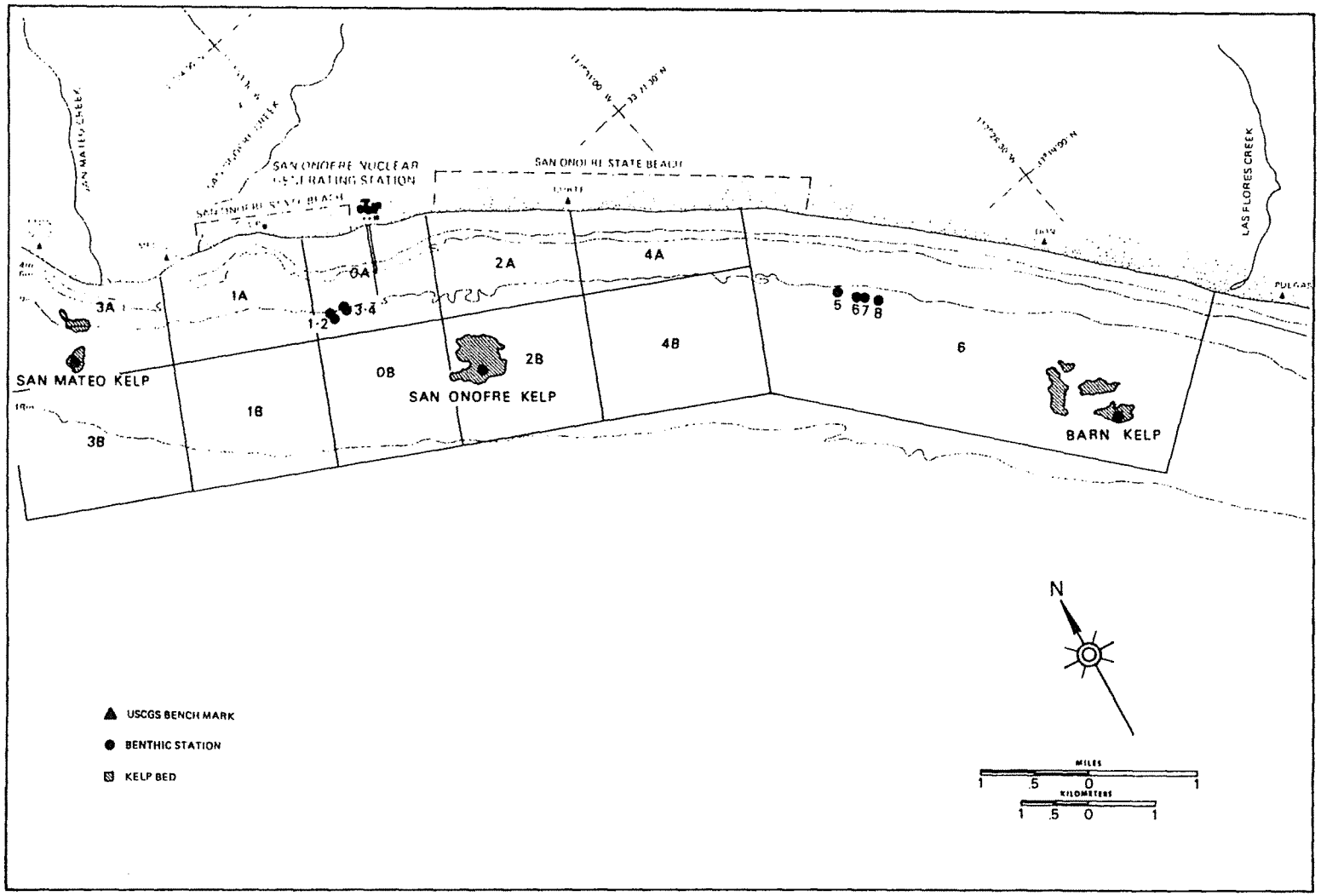

Fig. 2.9. Environmental Technical Specifications environmental surveillance zones, benthic station locations, San Onofre Nuclear Generating Station Unit 1. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

Table 2.6. Trophic composition (percent) of benthic taxa at discharge (zone 0A) and control (zone 6) based on the number of taxa of each trophic type present during 1975

	April 10–18		July 15–18		October 13–17	
Trophic types	Zone 0A	Zone 6	Zone 0A	Zone 6	Zone 0A	Zone 6
Primary producers	23	18	35	40	30	29
Suspension feeders	34	43	35	42	33	37
Grazers	10	3	12		12	5
Scavengers	13	13	7	10	12	11
Predators	20	22	12	7	13	18

Source: Lockheed Marine Biological Laboratory, *San Onofre Nuclear Generating Station Unit 1, Annual Analysis Report, Environmental Technical Specifications, January – December 1975,* 1976.

Kelp bed stations were best distinguished by four taxa: the gastropod *Cypraea spadicea*, which occurred only at San Onofre Kelp Bed; the anthozoan *Corynactis* spp., which occurred predominately at San Mateo and Barn kelp beds; the annelid *Spiochaetopterus costarum*, which did not occur at San Onofre Kelp Bed; and the white abalone, *Haliotis sorenseni*, which occurred only at San Onofre Kelp Bed. Twelve taxa were considered predominant at kelp bed stations: *Chelyosoma productum*, *Conus californicus*, *Corallina/Haliptylon*, *Corynactis* spp., Crustose corallines (unident.), *Dioptra* spp., *Leucilla nuttingi*, *Lytechinus pictus*, *Mitrella carinata*, *Muricea californica*, Pagurids (unident.), and *Rhodymenia* spp.

Trophic composition based on the number of taxa at the kelp bed stations was similar among stations and was dominated by suspension feeders (e.g., barnacles, which feed by filtering out suspended material) and primary producers (algae) during all surveys (Table 2.7).

Table 2.7. Trophic composition (percent) of benthic taxa at San Mateo (SMK), San Onofre (SOK), and Barn (BK) kelp beds based on the number of taxa of each trophic type present during 1975

	April 10–18			July 15–18			October 13–17		
Trophic types	SMK	SOK	BK	SMK	SOK	BK	SMK	SOK	BK
Primary producers	22	19	24	26	21	25	30	18	26
Suspension feeders	49	36	41	38	36	59	43	38	45
Grazers	2	17	9	8	12		7	10	4
Scavengers	12	12	9	12	12	9	7	12	10
Predators	15	17	17	16	18	6	12	22	16

Source: Lockheed Marine Biological Laboratory, *San Onofre Nuclear Generating Station Unit 1, Annual Analysis Report, Environmental Technical Specifications, January – December 1975,* 1976.

1976 Data

Diving surveys of the epibenthic macrobiota were conducted quarterly during 1976 at the same 11 benthic stations. A total of 159 species or higher taxa, which were members of 11 major taxonomic groups, were identified during the four surveys.[27] A taxonomic summary of these data by station and by survey is presented in Tables IV-1 and IV-2, pp. 21-28 of ref. 26. Zones 0A and 6 contained twelve predominant taxa whose combined abundance accounted for 84.3% of the total percent cover and 65.1% of the total enumerated individuals.[27] Seven of the twelve predominant taxa consisted of large taxonomic categories that were not field identifiable to a lower taxon. These seven taxa included parvosilvosa, unidentified ectoprocts, unidentified crustose coralline algae, and unidentified hydroids, rhodophytes, pelecypod siphons, and pagurids. These large taxonomic groups totaled 72% of the total percent cover and 20% of the total enumerated individuals for the entire year's data.[27] The magnitude of the abundances of these large taxonomic groups may be somewhat misleading, however, because each of these categories can contain members of several different species.[27]

The predominant taxa identified to at least the generic level consisted of *Rhodymenia* spp., *Bryopsis hypnoides*, *Diopatra ornata*, *Muricea californica*, and *Patiria miniata*. The distribution of these taxa among zones and stations is presented in Table V-12, p. 68 of ref. 27. The abundance of all of these taxa differed significantly between zones; *Rhodymenia* spp. and *Patiria miniata* were significantly more abundant in zone OA, whereas *Bryopsis hypnoides*, *Diopatra ornata*, and *Muricea californica* were significantly more abundant in zone 6. None of these taxa differed significantly among surveys.

A greater degree of similarity in both species composition and abundance was found within zones than between zones. Distribution of the anthozoan *Murica californica* and the rhodophyte *Prionitis* spp. contributed the greatest to the differences between zones OA and 6 in both years. Also in both 1975 and 1976, *M. californica* and the polychaete *Diopatra ornata* were significantly more abundant in zone 6. Species composition of the San Onofre Kelp Station was generally more similar to zone OA stations than to the other kelp bed stations; this is much the same as the 1975 survey data.

No significant differences existed between zones or kelp bed stations in the distribution of taxa among trophic levels during 1975 or 1976.

Aerial infrared kelp survey

An aerial infrared kelp survey revealed that both Barn and San Onofre kelp beds showed a slight increase in total area during 1975 (Fig. 2.10). All of the kelp beds increased in size between February and May 1976 (Fig. 2.10). During the period May to September 1976, Barn and San Onofre kelp beds underwent an 80 and 92% decrease respectively.[27] At the time of the November 1976 survey, Barn Kelp Bed had increased to 77% of the area it had covered during the May survey, whereas San Onofre Kelp Bed again underwent a slight decrease.[27] San Mateo Kelp Bed remained essentially the same. The same general trends were encountered during mapping of the kelp beds by electronic positioning during 1975 and 1976 as part of the construction surveillance program for SONGS 2 & 3.

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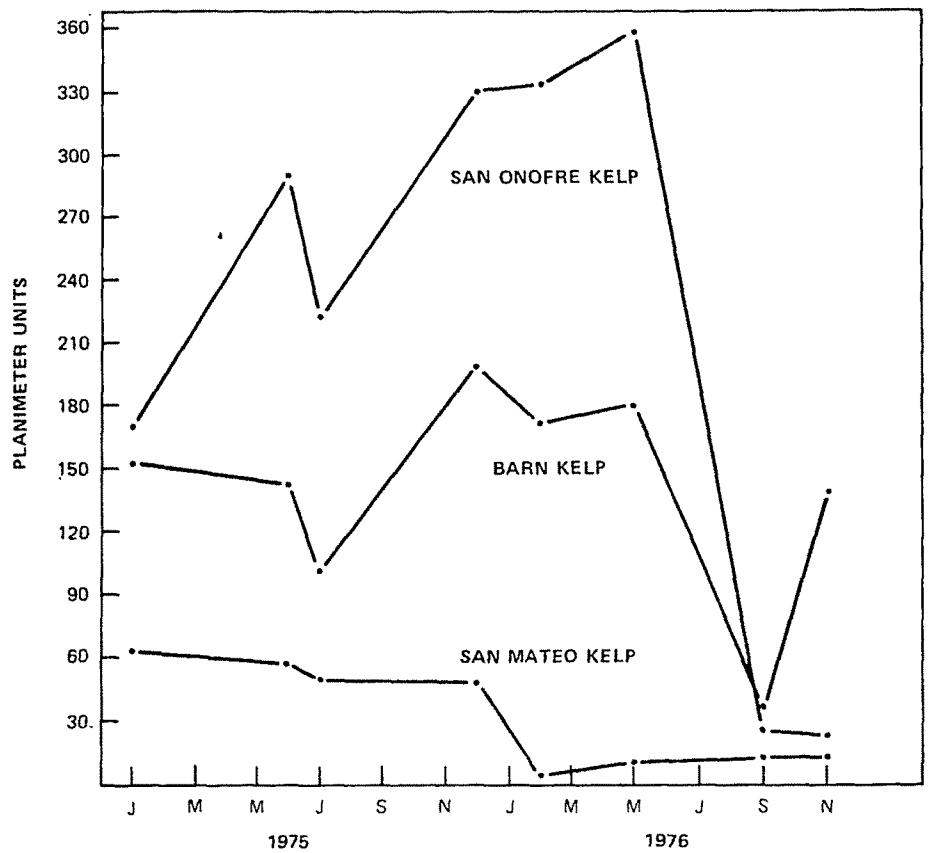

Fig. 2.10. Estimated relative total canopy area of San Mateo, San Onofre, and Barn kelp beds during 1975 and 1976, based on planimeter integration of aerial infrared photographs. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

Historical accounts of changes in kelp bed canopy areas throughout southern California have shown changes in magnitude equal to or much greater than those observed during this study, often over a short period of time.[27]

2.5.2.4 Intertidal community

1975 Data

During four intertidal surveys in 1975, 106 species or higher taxa representing 12 major taxonomic groups were observed at the five intertidal stations (Fig. 2.11).[25] These taxa are listed in Appendix XII, Tables 1 and 2, p. 246-52 of ref. 25. A comparison of the data collected in 1975 with historical data indicates that the fauna and flora encountered are typical inhabitants of this geographical area.[25] Phaeophytes, rhodophytes, and mollusks consistently exhibited the greatest number of taxa throughout the year at all stations. The distribution of five taxa were found to contribute significantly to the variability among stations: the rhodophytes *Corallina/Haliptylon, Pterocladia/Gelidium, Laurencia* spp.; the spermatophyte *Phyllospadix* spp.; and the anthozoan *Anthophleura* spp. Seventeen taxa, the majority of which were algae, were both common and abundant. The most abundant of these seventeen taxa were *Corallina/Haliptylon, Ulva* spp., and *Zonaria farolwii.*

Six predominant taxa exhibited distributions that varied significantly among stations, but no patterns that interrelated these differences were obvious. These six taxa were the anemone *Anthopleura* spp.; the rhodophytes *Corallina/Haliptylon, Lithothrix aspergillum, Pterocladia/Gelidium*; and the phaeophytes *Sargassum* spp. and *Zonaria farlowii.*

1976 Data

Quarterly intertidal sampling was also conducted in 1976. A taxonomic summary of these data by survey and station is presented in Table VI-1, pp. 35-38 of ref. 26.

Predominant taxa identified to at least the generic level were *Sargassum* spp., *Mitrella carinata, Macron lividus, Anthopleura elegantissima, Corallina/Haliptylon, Zonaria farlowii,* and *Dictyota/Pachydictyon.* The distribution of the abundance of these organisms for each station and for each survey is presented in Table VII-11, p. 104 of ref. 27. No significant differences were found in the abundance of *Dictyota/Pachydictyon, Macron lividus,* and *Mitrella carinata* among stations. The distribution of four taxa — *Corallina/Haliptylon, Zonaria farlowii, Sargassum* spp., and *Anthopleura elegantissima* — displayed statistically significant differences in abundance among stations. *Corallina/Haliptylon* was most abundant at station 5, *Zonaria farlowii* at stations 2 and 4, and *Sargassum* spp. was at station 3. The greatest number of *A. elegantissima* was observed at stations 1, 4, and 5.

The rhodophyte *Corallina/Haliptylon* contributed the most to the differences among stations during both 1975 and 1976 and was also predominant both years. During both years this taxon was more abundant at the station farthest downcoast of the SONGS 1 discharge and least abundant at the two stations upcoast of the discharge. Three other predominant taxa, *Sargassum* spp., *Zonaria farlowii,* and *Anthopleura elegantissima* exhibited statistically significant differences in abundance among stations during both 1975 and 1976. *Dictyota/Pachydictyon* exhibited no statistically significant differences in abundance among stations during either year.

No statistically significant difference in the distribution of taxa among trophic types existed among intertidal stations during either year. During both years, the intertidal communities of all stations were dominated by primary producers (algae).

The study area is accessible to considerable human intervention in the form of organism collecting in the tide pools, clam digging, surfing, and walking through intertidal cobble beds. Because of their accessibility via public roads, the stations nearest and upcoast of the generating station receive the heaviest use; the other stations receive less use because they are accessible only via hiking trail or the beach. Overall beach use in the study area is indicated by the San Onofre Beach State Park (which includes the study area) estimates of park use for 1976, which indicate that 378,483 people used the beach in the study area. The study area is also used heavily by clam diggers collecting littleneck clams, because this area is probably one of the most extensive and productive in the state. The large excavations and overturned cobble that result from clam digging may have considerable effect on the intertidal biota by disturbing habitats and interfering with mating activities.

Aerial infrared survey data on three occasions in 1976 revealed possible shore impingement of the 0.6°C (1°F) elevated temperature field at the four stations nearest the generating station. The 2°C (4°F) elevated field appeared to contact the shore immediately upcoast of the generating station but did not impinge on any intertidal cobble stations. Shore impingement of the elevated temperature field was not indicated in 1975.

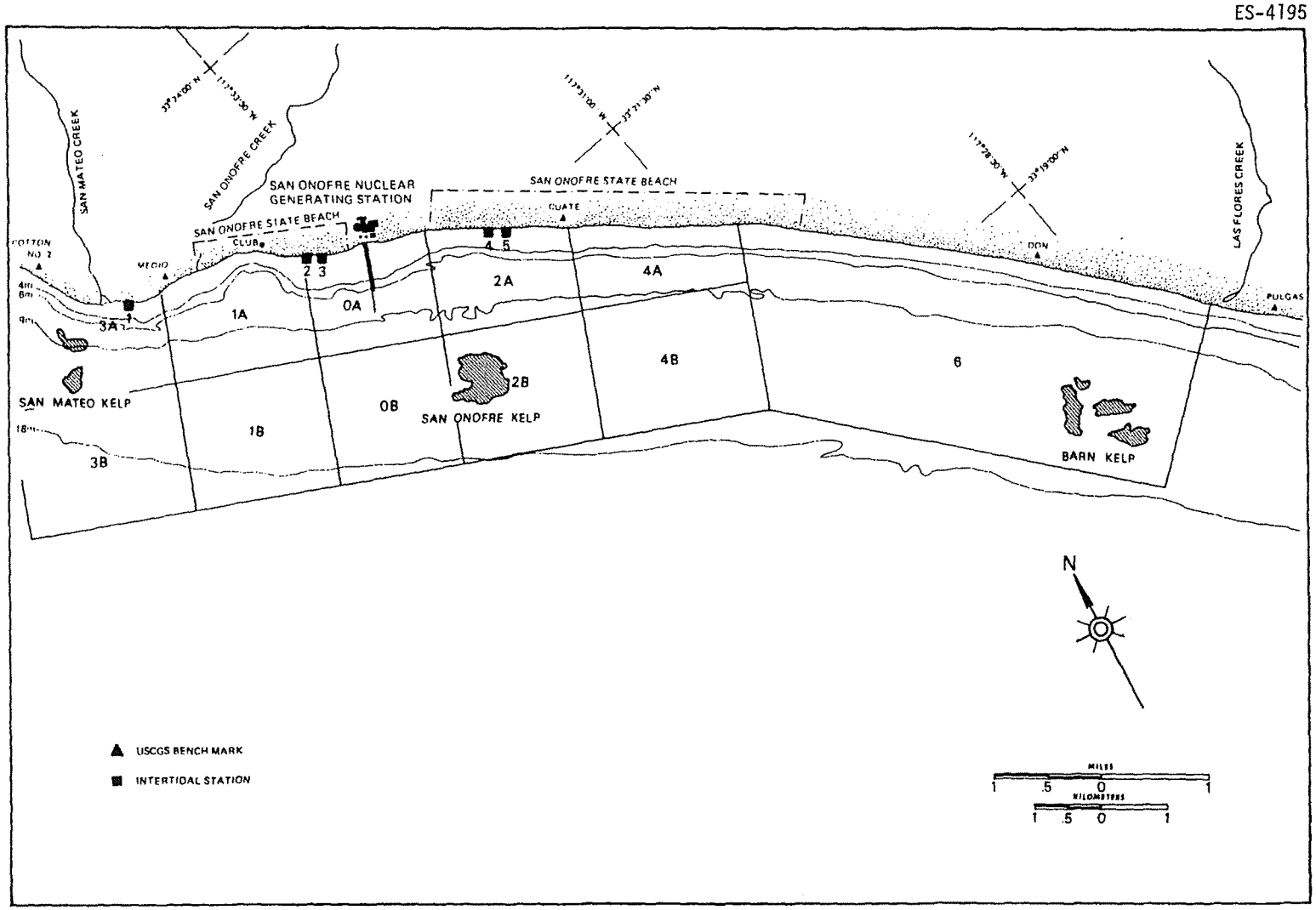

Fig. 2.11. Environmental Technical Specifications intertidal station locations and environmental surveillance zones, San Onofre Nuclear Generating Station Unit 1. Source: Lockheed Center for Marine Research, *San Onofre Nuclear Generating Station Unit 1, Environmental Technical Specifications, Annual Operating Report, Vol. IV, Biological Data Analysis — 1976*, June 1977.

Based on a comparison of the abundance of predominant taxa among stations and the similarity of stations during the study, the intertidal communities under study did not display a great deal of temporal variation during either 1975 or 1976. Minimal differences were detected among surveys with respect to the abundance of predominant taxa. These differences did not appear related to the offline condition of the generating station which occurred during two of four surveys.

2.6 BACKGROUND RADIOLOGICAL CHARACTERISTICS

The Environmental Protection Agency[29] has reported average background radiation dose equivalents for California as 96.6 millirems per person per year. The average background for San Diego is 104.6 millirems per person per year. (This is higher than the state average because of natural radioactivity in granitic rocks in the area.) Of the total for California, 42.2 millirems per person per year was attributed to cosmic radiation. Of this total external gamma radiation (primarily from K-40 and the decay products of the uranium and thorium series) was estimated at 36.4 millirems per person per year. The remainder of the whole body dose is due to internal radiation (mostly H-3, C-14, K-40, Ra-225, and Ra-228 and their decay products), which was estimated to average 18 millirems per person per year.

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3. THE PLANT

3.1 RESUME

The domestic water supply and service water system will now be supplied by the Tri-Cities Municipal Water District rather than obtained from flash boilers as previously contemplated (Sect. 3.2.1). The major design changes that have environmental effects relate to the heat dissipation system. The revised heat dissipation system is described in Sect. 3.2.2. These revisions and others result in a change in the chemical effluents and are discussed in Sect. 3.2.4.1. Changes in the radioactive waste treatment systems are described in Sect. 3.2.3. Significant changes have occurred in the transmission lines; the revised transmission line system is described in Sect. 3.2.5.

3.2 DESIGN AND OTHER SIGNIFICANT CHANGES

3.2.1 Plant water use

Both fresh water and seawater will be used at SONGS 2 & 3. About 0.05 m^3/sec (1.65 cfs) of fresh water will be supplied by the Tri-Cities Municipal Water District for the domestic water supply system and service water system. The major portion of the domestic water requirement will be used for landscaping and associated functions. The service water system will provide water to miscellaneous systems and equipment throughout the operating areas. A large amount of this fresh water will be used at the intake screenwell area for cooling of pump bearings.

The source of seawater is the Pacific Ocean. Cooling water will be withdrawn from the ocean at a rate of 53.5 m^3/sec (1887 cfs). This water will be used for turbine plant cooling, component cooling, main condenser cooling, and for the fish handling system. The turbine plant and component cooling water systems are closed-cycle systems. Heat is transferred to the seawater by heat exchangers.

Further details of the plant water use are given in Fig. 3.1.

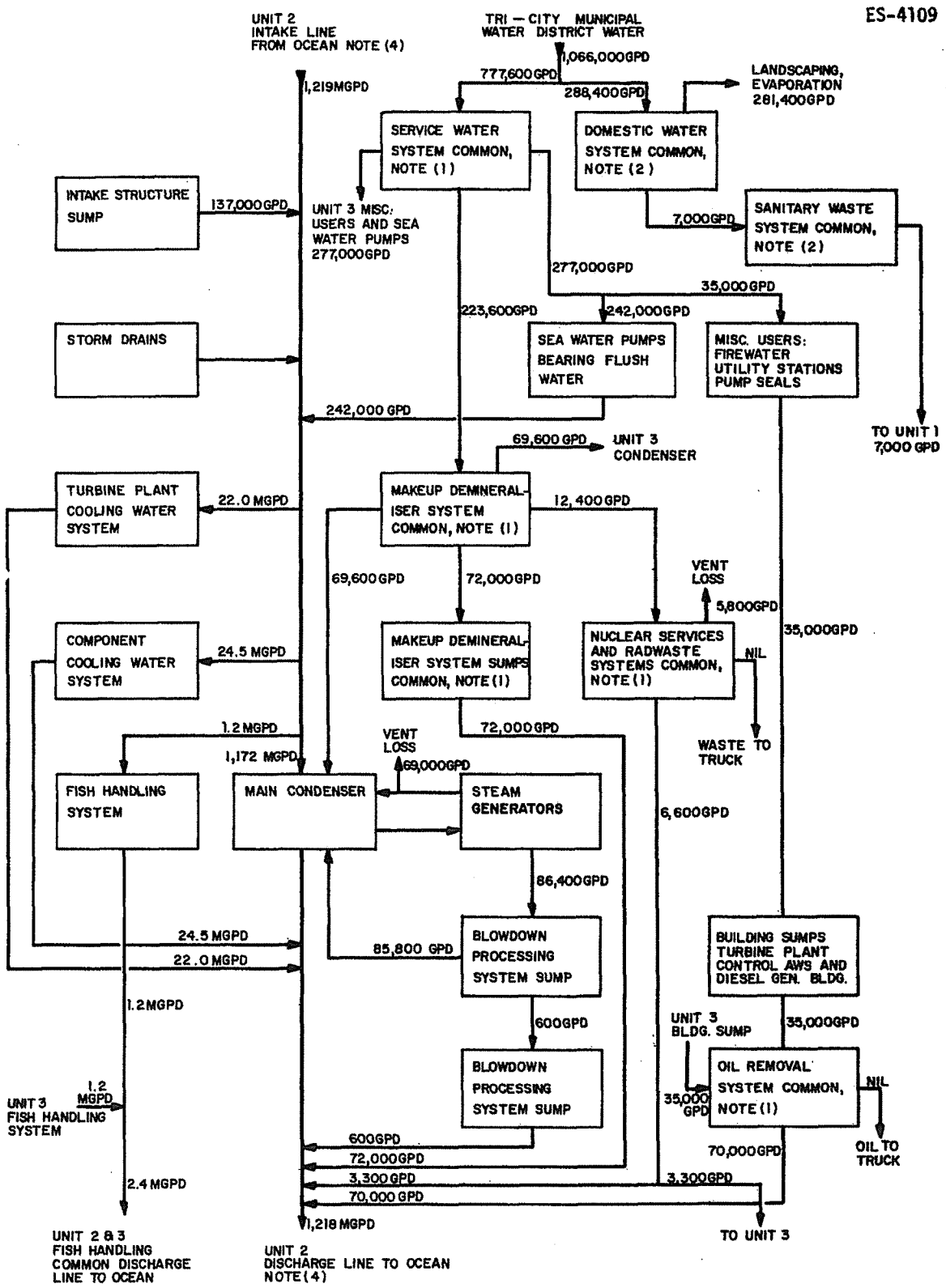
3.2.2 Heat dissipation system

Plant waste heat will be dissipated by means of a separate once-through cooling system for each unit. About 53.5 m^3/sec (1887 cfs) of seawater per unit is withdrawn from the ocean through a velocity-cap-type submerged intake, located about 975 m (3200 ft) from shore. The velocity cap is circular with a 15-m (50-ft) diameter. The lower lip of the cap is 2.7 m (9 ft) from the ocean bottom, and the interior separation of the upper and lower lip is 2.1 m (7 ft). The intake velocity will be about 0.5 m/sec (1.7 fps). The total water depth at the intake region is 9.1 m (30 ft). The intake structure is illustrated in Fig. 3.2.

Each unit has a Seismic Category I auxiliary intake structure to provide emergency core cooling. These structures are located approximately 32 m (100 ft) shoreward of the primary intake structures. Each structure has a 3.66 m (4-ft) ID vertical riser that extends upward from the intake conduit and is equipped with a velocity cap that is similar in design to that of the primary system. During normal operating conditions, water is estimated to enter the structure at 0.38 m/sec (1.3 fps). Details of these structures are shown in Fig. 3.2.

After passing through the intake, the cooling water for each unit will travel to the plant via a 5.5-m (18-ft) ID pipe that becomes a 4.9-m (16-ft) square box conduit at the shoreline. Here, water is delivered to a forebay leading to the intake structure screenwell. The water will then pass through a series of baffles as the channel widens to about 12.5 m (41 ft). At this point, the channel narrows and the main volume of water turns through an angle of 70°, where it passes through six adjacent sets of traveling bars and screens. A small volume of water does not turn towards these bars and screens but continues along the narrowing channel and enters the fish collection chamber.

Each screenwell is outfitted with traveling bar racks behind which are 1-cm (3/8-in.) mesh traveling screens. In the forebay behind the traveling screens are four 1/4-capacity vertical, wet pit,



Notes: (1) Common system, serves Units 2&3
(2) Common system, serves Units 2&3, AWS bldg
(3) MGPD, millions of gallons per day
(4) Unit 3 flows are same as Unit 2
(5) To convert GPD to liters per day, multiply by 3.7854

Fig. 3.1. Plant water use. Source: ER, Fig. 3.3-1.

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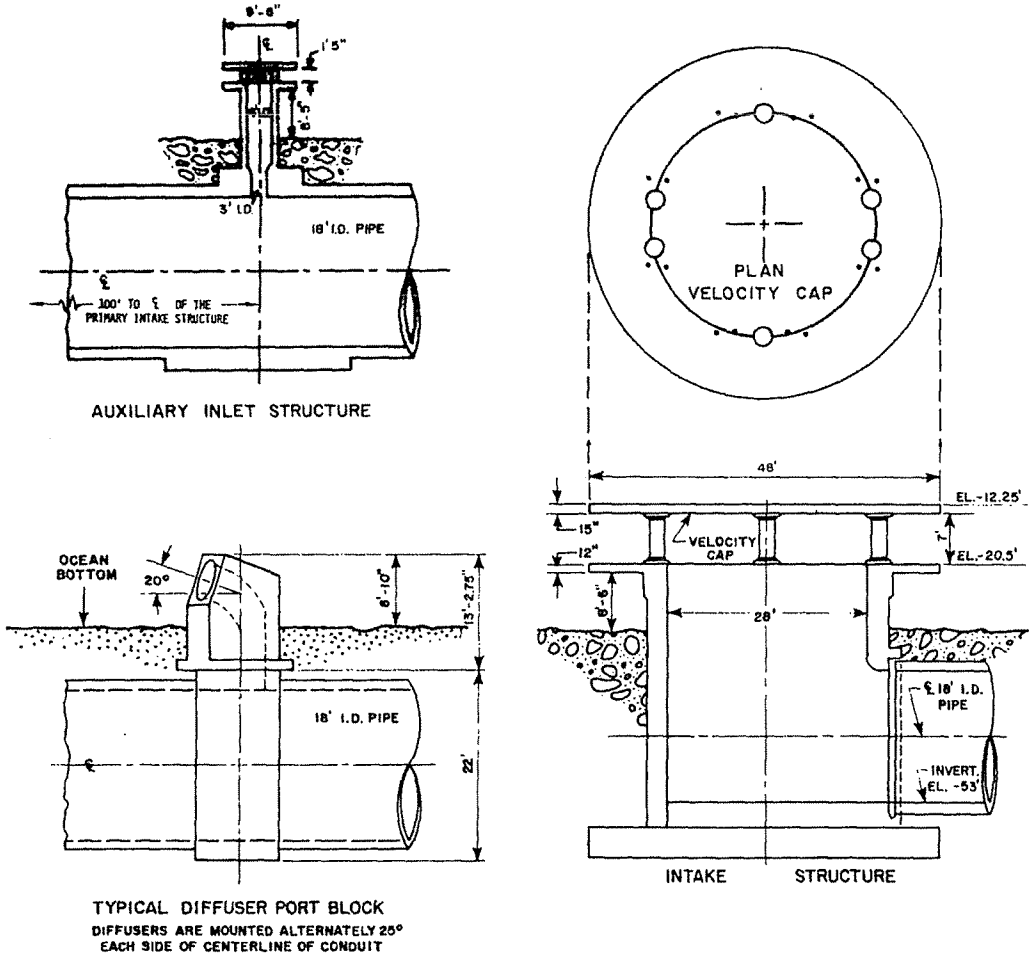

Fig. 3.2. Design details of the velocity-cap intake structure and typical diffuser port. Source: ER, Fig. 3.4-2.
(To convert ft to m, multiply by 0.3048.)

circulating water pumps. These pumps provide 50.3 m^3/sec (1775 cfs) of water to a two-shelled condenser. This water experiences an 11.1°C (20°F) temperature rise across the condenser. About 2.1 m^3/sec (75.8 cfs) of water is withdrawn prior to reaching the condenser for use in the turbine plant cooling loop and the fish return systems. Details of the intake screenwell structure are shown in Fig. 3.3.

After passing through the condenser, the heated water will pass through the Amertap strainer, which collects the Amertap balls used for cleaning the condenser tubes. Subsequently, this heated water is supplemented by 1.1 m^3/sec (37.9 cfs) of water from the turbine plant cooling system and screenwashing. The water then passes into a seal well weir chamber designed to ensure proper siphon flow through the condenser. This chamber terminates into a 4.9-m (16-ft) square box conduit to which 1.1 m^3/sec (37.9 cfs) of nuclear component cooling water flow is added. At the shoreline, this square conduit joins a 5.5-m (18-ft) ID buried pipe that conveys the heated water to the diffuser.

The diffuser for each unit is about 762 m (2500 ft) in length, and each diffuser has 63 ports spaced 12 m (40 ft) apart. Each port extends 1.8 m (6 ft) from the bottom and is oriented from the horizontal at an angle of 20°. The ports are alternately aligned at angles of ±25° from the offshore direction. The port throat diameter will vary from 56 cm (22 in.) to 61 cm (24 in.), and the maximum discharge velocity from any port will be 4 m/sec (13 fps). The Unit 3 diffuser begins about 1150 m (3800 ft) from shore, and the Unit 2 diffuser begins about 1950 m (6400 ft) from shore. The Unit 2 diffuser is located about 220 m (722 ft) upcoast of the Unit 3 diffuser.

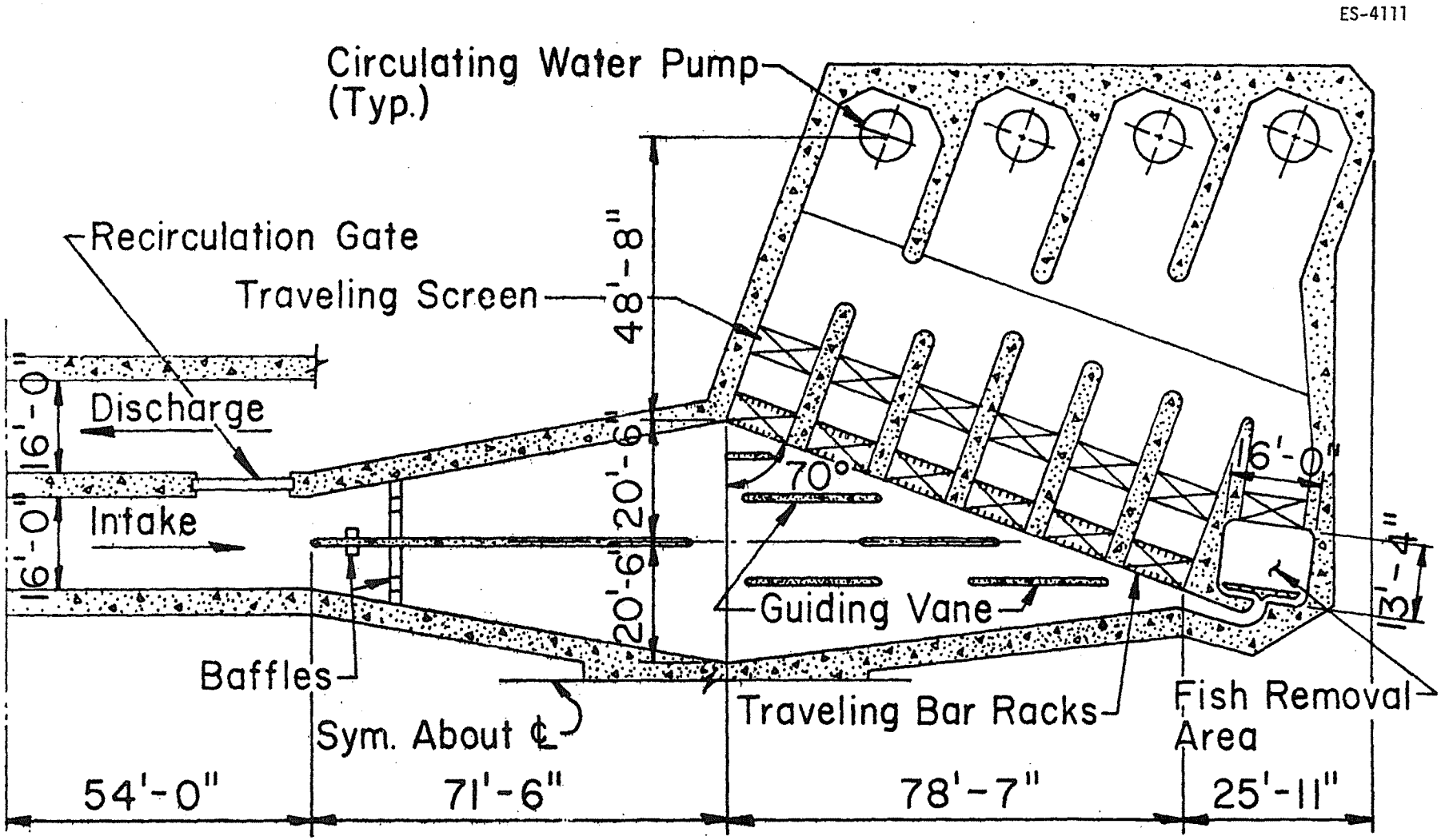

Fig. 3.3. Design details of the intake screenwell area. Source: ER, Fig. 3.4-3.
(To convert ft to m, multiply to 0.3048; to convert in. to mm, multiply by 25.4.)

To control biofouling, the circulating water system is designed to allow heated water to reach all portions of the system. To accomplish this, an intake/discharge crossover gate allows seawater to be drawn into the plant through the diffusers and the heated water to be discharged via the intake. To achieve the temperature required to control biofouling, each unit has a recirculation and crossover gate. This system allows the cooling water requirement to be reduced by recirculating a portion of the heated water through the condenser. The temperature rise will be proportional to the degree of recirculation. During diffuser heat treatment, the circulating water follows the normal path but with recirculation. Intake heat treatment is performed by opening the intake/discharge crossover gate to reverse the flow direction, as well as to allow recirculation. Circulating water flow paths for the various plant operations are shown in Fig. 3.4.

A fish return system minimizes the mortality of fish that have reached the intake screenwell area. The louvered bar racks are designed and oriented in such a way that the fish are encouraged to follow a narrowing channel terminating at a fish holding chamber. This chamber is equipped with a vertical elevator basket that periodically rises slowly from the bottom to capture the fish in the chamber. Subsequently, the fish are flushed from the basket with seawater into a 1.2-m (48-in.) diameter pipe, which returns them to the ocean via an offshore submarine outfall.

3.2.3 Radioactive waste systems

During the operation of SONGS 2 & 3 radioactive material will be produced by fission and by neutron activation of corrosion products in the reactor coolant system. From the radioactive material produced, small amounts of gaseous and liquid radioactive wastes will enter the waste streams. These streams will be processed and monitored within the station to minimize the quantity of radioactive nuclides ultimately released to the atmosphere and to the Pacific Ocean.

The waste handling and treatment systems to be installed at the station are discussed in the applicant's Final Safety Analysis Report (FSAR) and in the ER. Information submitted to meet the requirements of Appendix I to 10 CFR Part 50 is contained in both the FSAR and ER. In these documents, the applicant has presented an analysis of the radioactive waste treatment systems and has estimated the annual release of radioactive waste materials in liquid and gaseous effluents resulting from normal operation.

In the following paragraphs, the radioactive waste treatment systems are described, and an analysis is given based on the staff's model of the applicant's proposed radioactive waste treatment systems. The staff's model has been developed from a review of available data from operating nuclear power plants, adjusted to apply over a 30-year operating life. The reactor coolant activities and flow rates used in the staff's analyses are based on experience and data from operating reactors. As a result, the parameters used in the model and the calculated releases vary somewhat from those used in the applicant's evaluation.

On April 30, 1975, the NRC announced its decision in the rulemaking proceeding (RM 50-2) concerning numerical guides for design objectives and limiting conditions for operation to meet the criterion "as low as is reasonably achievable" for radioactive material in light-water-cooled nuclear power reactor effluents. This decision is implemented in the form of Appendix I to 10 CFR 50.[1] To effectively implement the requirements of Appendix I, the NRC staff has reassessed the parameters and mathematical models used in calculating releases of radioactive materials in liquid and gaseous effluents in order to comply with the Commission's guidance.

This guidance directed that current operating data, applicable to proposed radwaste treatment and effluent control systems for a facility, be considered in the assessment of the input parameters. These parameters, models, and their bases are given in NUREG-0017.[2]

By letter of February 25, 1976, the applicant was requested to submit additional information concerning the means proposed to keep levels of radioactive materials in effluents from SONGS 2 & 3 to unrestricted areas "as low as is reasonably achievable," in conformance with the requirements of Appendix I to 10 CFR 50. The applicant was also given the option of providing either a detailed cost benefit analysis or demonstrating conformance to the guidelines given in the September 4, 1975, Annex to Appendix I. The applicant chose to perform the cost-benefit analysis required by Sect. II.D of Appendix I to 10 CFR Part 50.

The staff performed an independent evaluation of the applicant's proposed methods to meet the requirements of Appendix I. The evaluation consisted of (1) a review of the information provided by the applicant, (2) a review of the applicant's proposed radwaste treatment and effluent control systems, (3) the calculation of new source terms based on models and parameters as given in NUREG-0017,[2] and (4) a cost-benefit analysis to determine the cost-effectiveness of proposed augments to the liquid and gaseous radwaste treatment systems.

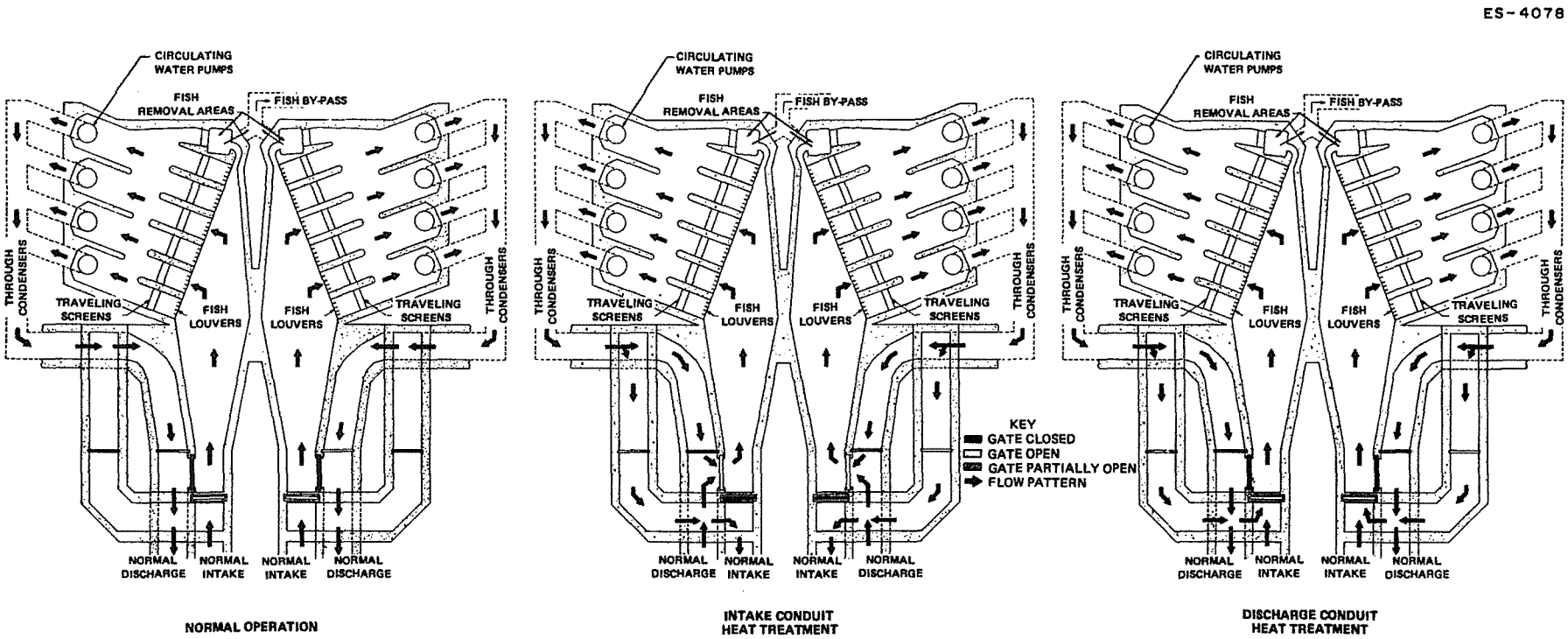

Fig. 3.4. Circulating water flow paths for normal plant operation, intake heat treatment, and discharge heat treatment. Source: Fig. 2-9 of *Thermal Effects Study Final Summary Report, San Onofre Generating Station Units 2 & 3 Volume 1*; Environmental Quality Analysts and Marine Biological Consultants, September 1973.

On the basis of the following evaluation, the staff concludes that the liquid and gaseous radio-active waste treatment systems for SONGS 2 & 3 are capable of maintaining releases of radioactive materials in liquid and gaseous effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a, and meet the requirements of Sect. II.A, II.B, II.C, and II.D of Appendix I to 10 CFR Part 50.[1]

3.2.3.1 Liquid radioactive waste treatment system

The liquid radioactive waste treatment system, which is shared by Units 2 and 3, will consist of equipment and instrumentation necessary to collect, process, monitor, recycle, or dispose of potentially radioactive liquid wastes generated during normal operation including anticipated operational occurrences. Liquid radioactive waste will be processed on a batch basis to permit optimum control of releases. Prior to release, samples will be analyzed to determine the types and amounts of radioactivity present; on the basis of the results, the waste will be recycled for reuse in the plant, retained for further processing, or discharged under controlled conditions to the Pacific Ocean via the circulating water outfall. A radiation monitor will automatically terminate liquid waste discharge if radiation measurements exceed a predetermined level in the discharge line. A schematic diagram of the liquid radioactive waste treatment system is given in Fig. 3.5.

The liquid radioactive waste treatment system will consist of the coolant radwaste (boron recovery) system, the miscellaneous (aerated) waste system, and the chemical waste system. The plant does not have a separate laundry and hot shower system; this function is combined in the aerated waste system.

The coolant radwaste system is shared by Units 2 and 3 and will process shim bleed and equipment drain wastes collected inside the reactor containment. The principal system components will be a gas stripper, four primary coolant radwaste holdup tanks, two preholdup demineralizers, two intermediate holdup tanks, two evaporator feed demineralizers, one evaporator, two polishing demineralizers, and two makeup storage tanks.

The miscellaneous liquid waste system will process non-reactor-grade liquid wastes, including floor drains, equipment drains containing non-reactor-grade water, and building sumps. After treatment these wastes will be transferred to the waste monitor tanks for reuse in the plant or for discharge to the Pacific Ocean via the circulating water outfall. The principal miscellaneous liquid waste system components will consist of one collection tank, four demineralizers, an optional evaporator, and two recycle monitor tanks. The liquid process stream may be routed through the optional evaporator if additional treatment is indicated.

The chemical waste system will process non-reactor-grade liquid wastes with high chemical content, including demineralizer regenerant solutions and laboratory drains. After treatment, these wastes will be transferred to the waste monitor tanks for reuse in the plant or for discharge to the Pacific Ocean via the circulating water outfall. The principal chemical waste system components will consist of one collection tank, an evaporator, two demineralizers, and two recycle monitor tanks.

The steam generator blowdown will be processed continually through a flash tank, with the liquid being cooled in a heat exchanger before passing through a filter and two demineralizers in series. The processed liquid is piped to the main condenser. The flashed steam is routed to the third point heater. The processed water will be reused in the plant, but may be discharged to the circulating water outfall under certain circumstances provided that radioactivity concentrations are below predetermined values.

Coolant radwaste system

Primary coolant will be withdrawn from the reactor coolant system at about 151 liters/min (40 gpm) and processed through the chemical and volume control system (CVCS). The letdown stream will be cooled, reduced in pressure, filtered, and processed through one of two mixed bed demineralizers. At the end of core cycle life this letdown stream will be passed through an anion demineralizer to remove boron when the feed and bleed mode of operation is not practicable. Radionuclide removal by the CVCS was evaluated by assuming 151-liters/min (40-gpm) letdown flow at primary coolant activity (PCA) through one mixed bed demineralizer (Li_3BO_3 form), and a continuous 30-liters/min (8-gpm) flow through one mixed bed demineralizer (H_3BO_3 form) for lithium control. The CVSC will be used to control the primary coolant boron concentration by diverting a side stream of about 3,785 liters/day (1000 gpd) per reactor of the treated letdown stream to the shared coolant radwaste system as shim bleed.

The shim bleed from the letdown stream will be processed through two mixed bed demineralizers (Li_3BO_3 form) in series, through a gas stripper, and routed to one of four 227,124-liter (60,000-gal) radwaste primary holdup tanks. Valve leakoffs and equipment drain wastes in the

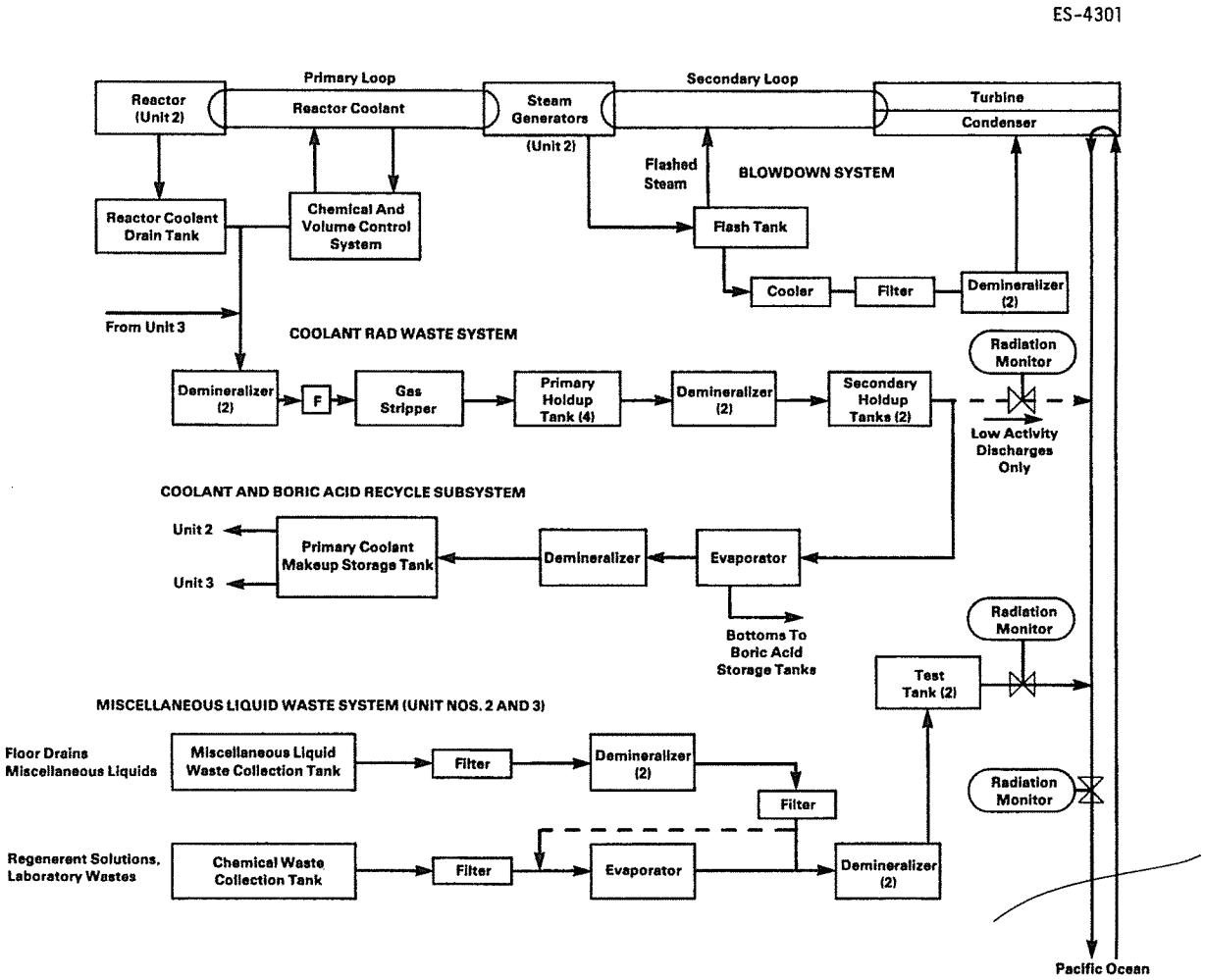

Fig. 3.5. SONGS 2 & 3 radioactive liquid waste treatment systems.

reactor containment, as well as excess spent fuel pit water, will be processed as above and will be transferred to the radwaste primary holdup tanks where it will be combined with the shim bleed. These streams will form the inputs to the coolant radwaste system and will be processed batchwise from the four radwaste primary holdup tanks. The combined streams are next processed batchwise through two mixed bed demineralizers (H_3BO_3 form) and routed to one of two 454,248-liter (120,000-gal) radwaste secondary holdup tanks. From the radwaste secondary holdup tanks, the processed liquid can be recycled to the reactor coolant makeup tank, can be discharged to the circulating water outfall if radioactivity concentrations are within established limits, or can be processed further through a boric acid evaporator and mixed bed deborating and polishing demineralizers.

In the latter mode of operation, the boric acid recovered in the evaporator bottoms can be recycled. Because the system is capable of continuously operating in the boron recovery mode with inputs from both Units 2 and 3, and because the staff's source term calculation assumes a failed fuel rate of 0.12%, the staff's evaluation was made on the basis of the system being operated in the boron recycle mode. The staff calculated the collection time in a radwaste secondary holdup tank to be about 38 days, based on a combined input flow rate of 9463 liters/day (2500 gpd) from Units 2 and 3. Based on an assumption of 80% tank capacity and process flow rate of 189 liter/min (50 gpm), the staff calculated the decay time during processing to be about 1.3 days. If the radioactivity is below predetermined value, the treated stream may be pumped to the waste monitor release tank and discharged. The staff assumed that 10% of the treated stream will be discharged to the circulating water outfall and to the Pacific Ocean because of anticipated operational occurrences and for tritium inventory control. The decontamination factors listed in Table 3.1 were applied for radionuclide removal in the coolant radwaste system. The concentrated bottoms from the evaporator and the spent resins from the demineralizers will be transferred to the radioactive solid waste system for disposal by burial offsite.

Miscellaneous liquid waste system

The miscellaneous liquid waste system of the liquid radioactive waste treatment system is designed to collect and treat non-reactor-grade water for reuse within the plant from auxiliary building sumps, the containment sumps, and other miscellaneous sources. These wastes will be collected in a shared 22,712-liters (6000-gal) waste holdup tank at an input flow rate of about 5300 liters/day (1400 gpd) per unit. The staff calculated the collection time to be about 1.7 days. The wastes will be processed through four series connected mixed bed demineralizers and collected in a 94,635-liter (25,000-gal) test tank. The staff calculated the decay time during processing to be about 0.03 days. If necessary, the stream can be diverted to the evaporator in the chemical waste system for additional treatment.

The decontamination factors listed in Table 3.1 were applied for radionuclide removal in the miscellaneous liquid waste system of the liquid waste treatment system. The contents of the treated stream will be sampled periodically, recycled for further treatment, recycled for in-plant use, or discharged. The staff assumed that 100% of the treated stream will be released to the Pacific Ocean.

Evaporator bottoms and spent resins will be transferred to the radioactive solid waste system for disposal by burial offsite.

Chemical waste system

The chemical waste system of the liquid radioactive waste treatment system is designed to collect and treat non-reactor-grade liquid wastes from laboratory drains and from the regeneration of demineralizers. These wastes will be collected in a shared 94,635-liter (25,000-gal) chemical waste tank and sampled and analyzed. The wastes will be treated through the chemical waste system evaporator and two series connected mixed bed demineralizers prior to entering the waste monitor tanks. The staff calculated the collection time to be about 25 days, based on an input flow of about 1514 liters/day (400 gpd) per unit, and a decay time during processing of about 0.1 day.

Turbine building drain

The turbine building drains will be released through a radiation monitor to the Pacific Ocean via the circulating water outfall without treatment. The monitor will automatically terminate liquid discharge if radioactivity exceeds a predetermined level. The staff assumed a release of 27,255 liters/day (7200 gpd) per reactor and that the wastes will be discharged without processing.

Table 3.1. Principal parameters and conditions used in calculating releases of radioactive material in liquid and gaseous effluents from SONGS 2 & 3

Reactor power level, MWt	3600
Plant capacity factor	0.80
Failed fuel, percent	0.12[a]
Primary system:	
Mass of coolant, lb	5.6×10^5
Letdown rate, gpm	40
Shim bleed rate, gpd	1×10^3
Leakage to secondary system, lb/day	100
Leakage to containment building	*b*
Leakage to auxiliary building, lb/day	160
Frequency of degassing for cold shutdowns, per year	2
Secondary system	
Steam flow rate, lb/hr	1.5×10^7
Mass of liquid steam generator, lb	1.7×10^5
Mass of steam/steam generator, lb	1.2×10^4
Secondary coolant mass, lb	2.2×10^6
Rate of steam leakage to turbine building, lb/hr	1.7×10^3
Containment building volume, ft^3	2×10^6
Annual frequency of containment purges, shutdown	4
Containment low volume purge rate (cfm)	2000
Iodine partition factors, gas/liquid	
Leakage to auxiliary building	0.0075
Leakage to turbine building	1.0
Main condenser/air ejector, volatile species	0.15

Liquid radwaste system decontamination factors (DF)

	Coolant radwaste system (CRS)	Miscellaneous liquid-waste system	Chemical-waste system
I	1×10^5	1×10^3	1×10^4
Cs, Rb	2×10^5	2×10^1	1×10^5
Others	1×10^6	1×10^3	1×10^5

	All nuclides except iodine	Iodine
Radwaste evaporator DF	10^4	10^3
Coolant radwaste system evaporator DF	10^3	10^2

	Anions	Cs, Rb	Other nuclides
Boron recycle feed demineralizer DF, H_3BO_3	10	2	10
Primary coolant letdown demineralizer DF, Li_3BO_3	10	2	10
Evaporator condensate polishing demineralizer, H^+OH^-	10	10	10
Mixed-bed radwaste demineralizer	10^2(10)	2(10)	10^2(10)
Steam generator blowdown demineralizer	10^2(10)	10(10)	10^2(10)
Containment building internal recirculation system charcoal filter DF, iodine removal			10
Main condenser air-removal system charcoal bed DF, iodine removal			10

[a]This value is constant and corresponds to 0.12% of the operating power fission product source term as given in NUREG-0017 (April 1976).

[b]One percent per day of the primary coolant noble gas inventory and 0.001% per day of the primary coolant iodine inventory.

(To convert lb to kg, multiply by 0.4536; to convert gals to liters, multiply by 3.7854; to convert ft^3 to m^3, multiply by 0.0283.)

Steam generator blowdown

The steam generator blowdown system for Units 2 and 3 will continuously process steam generator blowdown at an average flow rate of 325,545 liters/day (86,000 gpd) per reactor (design flow rate is 1136 liters/min (300 gpm)). The blowdown from the two steam generators for each unit will be directed to a common flash tank. The liquid will be cooled, filtered, and treated through two series connected demineralizers before being returned to the main condenser. The flashed steam will be condensed in the main condenser hotwell. The staff did not consider any direct releases from this system to the environment.

Liquid waste summary

Based on the staff's evaluation of the radioactive liquid waste treatment systems and the parameters listed in Table 3.1, the staff calculated the release of radioactive materials in liquid waste effluent to be about 1.1 Ci per year per reactor, excluding tritium and dissolved gases. The staff estimates that about 300 Ci per year per reactor of tritium will be released to the Pacific Ocean. In comparison, the applicant estimated a release of radioactive material in liquid effluent, exclusive of tritium, to be about 0.67 Ci per year per reactor and a tritium release of 710 Ci per year per reactor. The differences between the staff's values and those of the applicant lie principally in assumptions as to the parameters used for each radwaste system component and the distribution of tritium between gaseous and liquid releases. The staff's calculations of the radionuclides expected to be released annually from SONGS 2 & 3 are given in Table 3.2.

On the basis of the calculated releases of radioactive materials in liquid effluents given in Table 3.2, the staff calculated the annual dose or dose commitment to the total body or to any organ of an individual in an unrestricted area, as shown in Table 5.3, to be less than 3 millirem per reactor and 10 millirem per reactor, respectively, in conformance with Sect. II.A of Appendix I to 10 CFR Part 50.

Cost-benefit analysis of liquid radwaste system augments

The staff evaluated potential liquid radwaste system augments based on a study of the applicant's system designs, the population dose information provided in Table 5.3 of this statement, a value of $1000 per total body man-rem and $1000 per man-thyroid-rem for reductions in dose by the application of augments, and the methodology presented in Regulatory Guide 1.110.[3]

The principal parameters used in this cost-benefit analysis are: (1) labor cost correction factor, FPC Region VIII, 1.2 (Regulatory Guide 1.110[3]); (2) indirect cost factor, 1.75 (Regulatory Guide 1.110[3]); (3) cost of money, 15%; and (4) capital recovery factor, 0.0806 (Regulatory Guide 1.110[3]).

The calculated total body and thyroid doses from liquid releases to the projected population within a 80 km (50-mile) radius of the station, when multiplied by $1000 per total body man-rem and $1000 per man-thyroid-rem, resulted in cost-assessment values of $170 per year per unit and $140 per year per unit respectively. Potential radwaste system augments were selected from the list given in Regulatory Guide 1.110.[3] The most effective augment was the optional use of an existing 0.189 liters/min (50-gpm) evaporator in the miscellaneous liquid waste system; however, the calculated total annualized cost of $80,000 for operation and maintenance of the augment exceeded the cost-assessment values of $170 per unit for the total body man-rem dose and $140 per unit for the man-thyroid-rem dose. The staff concludes, therefore, that there are no cost-effective augments to reduce the cumulative population dose at a favorable cost-benefit ratio, and that the proposed liquid waste management system meets the requirements of Sect. II.D of Appendix I to 10 CFR Part 50.

3.2.3.2 Gaseous radioactive waste treatment system

The gaseous radioactive waste treatement and building ventilation exhaust systems will be designed to collect, store, process, monitor, recycle, and/or discharge potentially radioactive gaseous wastes that will be generated during normal operation including anticipated operational occurrences. The system will consist of equipment and instrumentation necessary to reduce releases of radioactive gases and particulates to the environment.

The principal source of radioactive gaseous wastes are the gaseous waste processing system, condenser vacuum pump, and ventilation exhausts from the auxiliary, radwaste, fuel handling, containment, and turbine buildings. The principal system for treating gaseous wastes stripped from the primary coolant will be the gaseous waste processing system (GWPS). The GWPS will be a once-through nitrogen system containing a surge tank, two compressors, and six pressurized storage tanks. The off-gas from the main condenser air ejector will be processed through HEPA

Table 3.2. Calculated releases of radioactive materials in liquid effluents from SONGS 2 & 3

Nuclide	Curies per year per unit
Corrosion and activation products	
Cr-51	5.6(−4)
Mn-54	9(−5)
Fe-55	4.9(−4)
Fe-59	3(−4)
Co-58	4.8(−3)
Co-60	6.1(−4)
Np-239	2.5(−5)
Fission products	
Br-83	7(−5)
Rb-86	1.1(−3)
Rb-88	1.4(−2)
Sr-89	1(−4)
Sr-91	4(−5)
Y-91m	3(−5)
Y-91	2(−5)
Zr-95	2(−5)
Nb-95	1(−5)
Mo-99	1.9(−2)
Tc-99m	1.5(−2)
Ru-103	1(−5)
Rh-103m	1(−5)
Te-127m	8(−5)
Te-127	1.1(−4)
Te-129m	4.1(−4)
Te-129	2.8(−4)
I-130	1.9(−4)
Te-131m	4(−4)
Te-131	7(−5)
I-131	8.1(−2)
Te-132	6.2(−3)
I-132	7.8(−3)
I-133	5.3(−2)
I-134	2.3(−4)
Cs-134	3.5(−1)
I-135	9.5(−3)
Cs-136	1.7(−1)
Cs-137	2.5(−1)
Ba-137m	1.6(−1)
Ba-140	6(−5)
La-140	4(−5)
Ce-141	2(−5)
Pr-143	1(−5)
All others	5(−5)
Total, except H-3	1.1
H-3	300

filters and charcoal absorbers prior to release to the environment. The containment building atmosphere will be recirculated through HEPA filters and charcoal absorbers prior to release to the environment. Ventilation exhaust air from the auxiliary building and the fuel handling area will not be processed prior to release to the environment. The turbine building ventilation exhaust air will be released to the environment without treatment. The gaseous waste and ventilation treatment systems are shown schematically in Fig. 3.6.

Gaseous waste processing system (GWPS)

The GWPS will be designed to collect and process gases stripped from the primary coolant in the CVCS, coolant radwaste system, and miscellaneous tank cover gases. The GWPS is shared between Units 2 and 3. The GWPS will contain an inventory of nitrogen and hydrogen which will act as a carrier gas to transport radioactive gases removed from the primary coolant. Hydrogen and nitrogen cover gases from the volume control and reactor coolant drain tanks, and gases stripped in the coolant radwaste system degasifier will be collected, compressed, and stored in one of six pressurized storage tanks. The storage tanks will collect and store gases to allow short-lived radionuclide decay. After holdup, the gases will be discharged to the environment.

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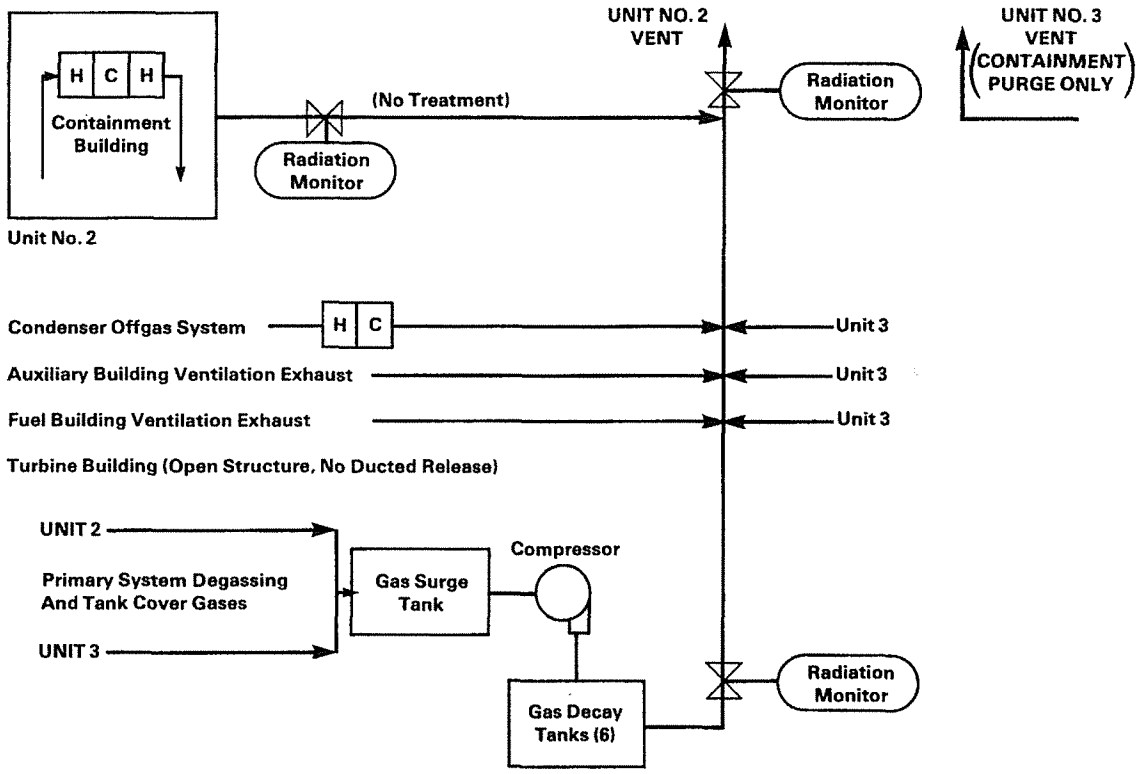

Fig. 3.6. SONGS 2 & 3 radioactive gaseous waste treatment systems.

In its evaluation, the staff assumed three tanks for storage, with two tanks held in reserve for back-to-back shutdowns, and one tank in the process of filling. Each tank has a volume of 14.16 m^3 (500 ft^3) and operates at 300 psig. On this basis, the staff calculated a holdup time of 90 days prior to discharge of gases to the environment.

Containment ventilation system

Radioactive material will be released inside the containment when primary system leakage occurs. The staff assumed on the basis of system parameters that the containment will be purged continuously during power operations at 56.6 m^3/min (2000 cfm) and in addition will have four high volume shutdown purges per year at 1132 m^2/min (40,000 cfm). Prior to purging, the containment atmosphere will be recirculated through HEPA filters and charcoal absorbers. The staff assumed radionuclide removal during the recirculation phase to be based on a flow rate of 453 m^3/min (16,000 cfm), system operation for 16 hr, a mixing efficiency of 70%, a particulate decontamination factor of 100 for HEPA filters, and an iodine decontamination factor of 10 for charcoal absorbers. The purge exhaust gases are released without filtration or other treatment.

Ventilation releases from other buildings

Radioactive materials will be released into the plant atmosphere due to leakage from equipment transporting or handling radioactive materials. Ventilation air from the auxiliary building and fuel building is not processed prior to release. The staff estimated that 72.58 kg (160 lb) of primary coolant per day will leak to the auxiliary building with an iodine partition factor of 0.0075. Small quantities of radionuclides will be released to the open turbine building, based on an estimated 771 kg/hr (1700 lb/hr) of steam leakage. The open turbine building releases will be released directly to the environment.

Main condenser air ejector

Off-gas from the main condenser air ejectors will contain radioactive gases as a result of primary to secondary leakage. In its evaluation, the staff assumed a primary to secondary leak rate of 45 kg/day (100 lb/day). Noble gases and iodine will be contained in steam generator leakage and released to the environment through the main condenser air ejectors in accordance with the partition factors listed in Table 3.1. The air ejector exhaust will be released to the environment through HEPA filters and charocal absorbers.

Gaseous waste summary

Based on the staff's evaluation of the gaseous radioactive waste treatment and building ventilation systems and the parameters listed in Table 3.1, the staff calculated the release of radioactive materials in gaseous effluents to be about 15,000 Ci per year per unit for noble gases and 0.44 Ci per year per unit for iodine-131. In comparison, the applicant estimated a release of 8600 Ci per year per unit for noble gases and 0.096 Ci per year per unit for iodine-131. The staff estimated a release of 0.39 Ci per year per unit of particulates and 1100 Ci per year per unit of tritium. The applicant estimated a release of 0.2 Ci per year per unit of particulates and 710 Ci per year per unit of tritium.

The staff's calculated annual releases of radioactive materials in gaseous effluents from radionuclides expected to be released annually from SONGS 2 & 3 are given in Table 3.3. Based on the calculated releases of radioactive materials in gaseous effluents given in Table 3.3, the staff calculated the annual air in an unrestricted area, as shown in Table 5.3. to be less than 10 millirads per reactor for gamma radiation or 20 millrads per reactor for beta radiation and the annual external doses to the total body and skin of an individual in an unrestricted area to be less than 5 millirems and 15 millirems, respectively, and an organ dose of less than 15 millirems per reactor for radioiodine and radioactive particulates in conformance with Sect. II.B and II.C of Appendix I to 10 CFR 50.

Table 3.3. Calculated releases of radioactive materials in gaseous effluents from SONGS 2 & 3 (Curies per year per unit)

Nuclide	Decay tanks	Reactor building	Auxiliary building	Turbine building	Air ejector	Total
Kr-83m	*a*	2	*a*	*a*	*a*	2
Kr-85m	*a*	24	2	*a*	2	28
Kr-85	430	170	5	*a*	3	610
Kr-87	*a*	5	1	*a*	*a*	6
Kr-88	*a*	30	4	*a*	3	37
Kr-89	*a*	*a*	*a*	*a*	*a*	*a*
Xe-131m	*a*	90	3	*a*	2	95
Xe-133m	*a*	140	5	*a*	3	150
Xe-133	*a*	13,000	410	*a*	260	14,000
Xe-135m	*a*	*a*	*a*	*a*	*a*	*a*
Xe-135	*a*	120	8	*a*	5	130
Xe-137	*a*	*a*	*a*	*a*	*a*	*a*
Xe-138	*a*	*a*	*a*	*a*	*a*	*a*
Total noble gases						15,000
I-131	*a*	0.35	0.08	0.0042	0.005	0.44
I-133	*a*	0.27	0.09	0.0033	0.0056	0.37
Mn-54	4.5(−3)[b]	2.2(−2)	1.8(−2)	*c*	*c*	4.4(−2)
Fe-59	1.5(−3)	7.4(−3)	6(−3)	*c*	*c*	1.5(−3)
Co-58	1.5(−2)	7.4(−2)	6(−2)	*c*	*c*	1.5(−2)
Co-60	7(−3)	3.3(−2)	2.7(−2)	*c*	*c*	6.7(−2)
Sr-89	3.3(−4)	1.7(−3)	1.3(−3)	*c*	*c*	3.3(−3)
Sr-90	6(−5)	2.9(−4)	2.4(−4)	*c*	*c*	5.9(−4)
Cs-134	4.5(−3)	2.2(−2)	1.8(−2)	*c*	*c*	4.4(−2)
Cs-137	7.5(−3)	3.7(−2)	3(−2)	*c*	*c*	7.4(−2)
Total particulates						1.2
H-3						1,100
C-14	7	1	*a*	*a*	*a*	8
Ar-41	*a*	25	*a*	*a*	*a*	25

[a] Less than 1 Ci/year for noble gases and carbon-14, less than 10^{-4} Ci/year for iodine.
[b] Exponential notation: 4.5(−3) = 4.5×10^{-3}.
[c] Less than 1% of total for this nuclide.

Cost-benefit analysis of gaseous radwaste system augments

The staff has evaluated potential gaseous radwaste system augments based on a study of the applicant's system designs, the population dose information provided in Table 5.3 of this statement, a value of $1000 per total body man-rem and $1000 per man-thyroid-rem for reductions in dose by the application of augments, and the methodology presented in Regulatory Guide 1.110.[3]

The calculated total body and thyroid doses from gaseous releases to the population within a 80 km (50-mile) radius of the station, when multiplied by $1000 per total body man-rem and $1000 per man-thyroid-rem, resulted in cost-assessment values of $21,000 per year per unit and $46,000 per year per unit respectively. Potential radwaste system augments were selected from the list given in Regulatory Guide 1.110. The most effective augment considered was the installation of charcoal adsorbers and HEPA filters on the containment mini-purge ventilation exhaust. The addition of this augment would result in a dose reduction of approximately 6.3 total-body man-rem and 23.8 thyroid man-rem with corresponding cost assessment values of $6,300 and $23,800, respectively. The calculated total annualized cost of $26,500 for the augment is more than the annual cost assessment values of $6,300 and $23,800 given above. The staff concludes, therefore, that there are no cost-effective augments to reduce the cumulative population dose at a favorable cost-benefit ratio, and the proposed gaseous waste treatment and ventilation systems meet the requirements of Sect II.D of Appendix I to 10 CFR Part 50.[1]

The staff concludes that the gaseous radwaste system for Units 2 and 3 is capable of maintaining releases of radioactive materials in gaseous effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a and meets the requirements of Appendix I to 10 CFR Part 50. The staff, therefore, concludes that the proposed system is acceptable.

3.2.3.3 Solid wastes

The solid waste system will be designed to process two general types of solid wastes: "wet" solid wastes which require solidification prior to shipment, and "dry" solid wastes which require packaging and, in some cases, compaction prior to shipment to a licensed burial facility. "Wet" solid wastes will consist mainly of spent filter cartridges, demineralizer resins, and evaporator bottoms which contain radioactive materials removed from liquid streams during processing. "Dry" solid wastes will consist mainly of low-activity ventilation air filters, contaminated clothing, paper, and miscellaneous items such as laboratory glassware and tools. Spent resins from the demineralizers will be collected in the spent resin storage tank. When the resin is to be packaged, it will be sluiced to a disposable liner and dewatered before solidification. The resin beads are solidified by filling the void spaces with urea formaldehyde and catalyst. A disposable paddle is used to agitate the mixture in the liner during the solidification process. Concentrated evaporator wastes will be collected in an evaporator bottoms tank, and then pumped batchwise through an inline mixer where they are blended with a urea formaldehyde solution. From the inline mixer, the mixture is sprayed into a disposal liner while a liquid catalyst is simultaneously sprayed into the liner by a separate nozzle to assure intimate mixing of the waste-urea formaldehyde solution and the catalyst.

On the basis of its evaluation and on recent data from operating plants, the staff has determined that about 425 m^3 (15,000 ft^3) per unit of "wet" solid wastes, containing about 1060 Ci of activity, will be shipped offsite annually. The principal radionuclides in the solid wastes will be long-lived fission and corrosion products, mainly Cs-134, Cs-137, Co-58, Co-60 and Fe-55. The applicant estimated the combined production of solid wastes from Units 2 and 3 to be 283 m^3/yr (10,000 ft^3/ year) of solidified wastes. The applicant calculated the total curie content of these solid wastes to be about 6500 Ci. The waste containers will be stored in a shielded area, as required, to reduce contact radiation levels.

Dry solid wastes will be packaged in cardboard boxes, wooden boxes, and special DOT-approved containers. Compressible wastes such as clothing and rags will be compressed prior to packaging. The staff estimates the dry solid wastes to total 283 m^3 (10,000 ft^3) per unit per year with a total activity content of less than 5 Ci. The applicant estimates the combined production of dry wastes from Units 2 and 3 to be 207 m^3/yr (7300 ft^3/year) with a calculated total curie content of about 21 Ci.

3.2.4 Chemical, sanitary, and other waste effluents

3.2.4.1 Chemical effluents

Several design changes have had significant impacts on chemical discharges. The condenser tubes are made of titanium (ER, Table 3.4-1) rather than of a copper-nickel alloy; this should eliminate the small amounts of copper and nickel in the discharge as described previously

(FES-CP, Sect. 3.5.1). An Amertap condenser tube cleaning system has been installed (ER, Sect. 3.4.4). In this system, sponge rubber balls are injected into the inlet piping of the condenser and are forced through the condenser tubes to scrape them clean. The balls are collected in the circulating water discharge conduit and are recirculated. This change helps to control fouling within the circulating water system and should reduce the frequency of chlorination necessary to maintain a clean condenser system. A makeup demineralizer system will replace the flash evaporators. Chemicals originally indicated as being discharged from the flash evaporators (FES-CP, Table 3.9) will not be discharged. A cellulose sealant for the circulating water system (FES-CP, Sect. 3.5.1) will not be used. Steam generator blowdown will be treated by filtration and demineralization and will be recycled to the condenser. Phosphates will not be added to the blowdown (FES-CP, Sect. 3.5.2), and the discharge of salts and heavy metal ions will be eliminated.

The only significant chemical discharge results from the use of sodium hypochlorite as a biocide. The chlorination system is common to both Units 2 and 3. The two units will not be treated at the same time. Hypochlorite solution will be injected into the circulating water pump discharge headers three times each day. Each injection will last about 15 min but will not exceed 90 min per unit per day. The chlorine residual in the circulating water discharge line is monitored by amperometric titration, and the addition of hypochlorite is adjusted to maintain a 0.5-mg/liter (1.89 grains/gal) maximum concentration of free available chlorine. The applicant estimates that this will result in a maximum free available chlorine concentration of 0.1 mg/liter (0.38 grains/gal) in the immediate vicinity of the discharge.

Other chemicals may be discharged at certain times. These chemicals generally will be discharged at low concentrations and, when mixed with the circulating water flow, represent a negligible concentration at the discharge to the ocean. During restarts the discharge of condensate from the hotwell may contain concentrations of several milligrams per liter of iron and copper. These substances will be reduced to negligible concentrations in the circulating water discharge. The discharge from the regeneration of demineralizers will contain sodium and sulfate ions; the concentrations at the discharge to the ocean will be less than 10 mg/liter (38 grains/gal) – negligible concentrations as compared to the natural concentrations in seawater. Small amounts of oil, not to exceed 5 mg/liter (19 grains/gal), will be discharged from the oil removal system and diluted to negligible concentration in the circulating water discharge. Various closed-loop cooling systems will be treated with potassium chromate to inhibit corrosion.

Offsite rainfall runoff from the coastal hills and from Interstate Highway 5 (I-5) is collected by the storm runoff drainage system for the highway. Part of this drainage is discharged directly to the ocean and part is discharged with the onsite plant drainage. Onsite plant drainage is collected in catch basins and is discharged with the circulating water discharge. Drainage collected in areas in which significant quantities of oil or grease might be present are routed through the oil removal system.

A National Pollutant Discharge Elimination System (NPDES) permit for SONGS 2 & 3 was issued on June 14, 1976, by the California Regional Water Quality Control Board, San Diego Region. The chemical effluent limitations for the combined discharges (cooling water, low-volume wastes, and storm drains) are: (1) the monthly average free available chlorine discharged shall not exceed 0.2 mg/liter (0.757 grains/gal), and the daily maximum shall not exceed 0.5 mg/liter (1.89 grains/gal); (2) discharge of free available chlorine or total residual chlorine from any plant unit for more than 2 hr in any one day or for more than one unit in the plant at any one time is prohibited; (3) the pH of the effluent shall be within the range of 6.0 to 9.0; and (4) after July 1, 1976, the discharge shall not exceed the limits given in Table 3.4. The permit prohibits the discharge of any chemicals or pollutants from the fish handling system. The low-volume waste discharge shall not exceed the following limits: (1) a monthly average of 30 mg/liter (113.6 grains/gal) and a daily maximum of 100 mg/liter (378.6 grains/gal) for total suspended solids and (2) a monthly average of 15 mg/liter (56.78 grains/gal) and a daily maximum of 20 mg/liter (75.7 grains/gal) for oil and grease. The discharge from the storm drains shall not exceed a monthly average of 10 mg/liter (38 grains/gal) and a daily maximum of 15 mg/liter (56.78 grains/gal) for oil and grease.

3.2.4.2 Sanitary and other waste effluents

Sanitary wastes from Units 2 and 3 will receive secondary level treatment in the sewage treatment plant located at Unit 1, which will serve all three units. The treated wastes will have the following water quality characteristics (average daily concentration): suspended solids, 30 mg/liter (113.6 grains/gal); biological oxygen demand, 30 mg/liter(413.6 grains/gal); coliform, mean probable number of 200 per 100 ml (59 per ounce); pH, 7.0 to 8.5; and total residual chlorine, 2.0 mg/liter (7.57 grains/gal) (ER, Table 5.4-1). The treated wastes will be discharged into the Unit 1 circulating water discharge at an average rate of about 0.02 m^3/min (5 gpm). Because the circulating water discharge at Unit 1 is about 1200 m^3/min (320,000 gpm), the sanitary waste effluents will be reduced to negligible concentrations at the point of discharge to the ocean. The sanitary waste effluents for all three units will be within the

Table 3.4. NPDES chemical effluent limitations

Constituent	Concentration (mg/liter) not to be exceeded more than	
	50% of time	10% of time
Arsenic	0.01	0.02
Cadmium	0.02	0.03
Total chromium	0.005	0.01
Copper	0.2	0.3
Lead	0.1	0.2
Mercury	0.001	0.002
Nickel	0.1	0.2
Silver	0.02	0.04
Zinc	0.3	0.5
Cyanide	0.1	0.2
Phenolic compounds	0.5	1.0
Total chlorine residual	1.0	2.0
Ammonia (as N)	40	60
Total identifiable chlorinated hydrocarbons	0.002	0.004
Toxicity concentration	1.5[a]	2.0[a]

[a]Toxicity units.
Source: ER, Appendix 12C.

(To convert mg/liter to grains/gal, multiply by 3.785.)

limitations established for Unit 1 by the California Regional Water Quality Board and the Environmental Protection Agency.

Some gaseous wastes from the operation of diesel generators and the auxiliary boiler will be discharged intermittently. Four diesel generators will serve Units 2 and 3, and it is anticipated that these will operate for about 2 hr once per month. The estimated hourly full-load emission in kilograms (pounds) from each generator is nitrogen oxides, 84 (185); sulfur dioxide, 11 (25); particulates, 0.9 (2); hydrocarbons, 3.9 (8.5); and carbon monoxide, 9.5 (21) (ER, Sect. 3.7.4.1). A single auxiliary boiler will be used for both Units 2 and 3. This boiler will be operated for varying time periods throughout the life of the plant (ER, Sect. 3.7.4.2). The maximum annual use is expected to be 1250 hr at full load and 3130 hr at half load. Under these conditions, the anticipated annual emissions in tonnes (tons) are nitrogen oxides, 44 (49); sulfur dioxide, 98 (108); and particulates, 34 (38).

Trash from screens for the circulating water system for Units 2 and 3 will be taken to the Bonsall Sanitary Landfill near the city of Vista, California. This landfill is used for the disposal of trash from Unit 1.

3.2.5 Transmission lines

Much of the description of the transmission lines presented in Sect. 3.7 of the FES-CP is no longer valid. Construction of SCE's transmission line from SONGS to Santiago Substation will be completed only up to Santiago Tap, thereby deleting that portion between Santiago Tap and Santiago Substation. SDG&E's line from Telega Substation to Escondido Substation has also been deleted. SCE will retrofit transmission lines from SONGS to Santiago Tap, Santiago Tap to Santiago Substation, and Santiago Tap to Black Star Canyon Tap. SDG&E will add a line from SONGS to Mission Substation. SDG&E's lines from SONGS to Telega Substation and SONGS to Encina Substation will still be constructed but the staff has received additional information with regard to these lines since issuance of the FES-CP. Therefore, these lines will be further discussed in Sect. 3.2.5.2. All transmission lines for operation of SONGS Units 2 and 3 are illustrated in Figs. 3.7 and 3.8. Generally, the lines are coastal, using existing rights-of-way traversing northward from SONGS to Talega Substation, Santiago Tap, Santiago Substation, and Black Star Canyon Tap, and southeast to Encina and Mission Substations. A total of about 159.1 km (98.9 miles) will be crossed by the transmission lines. No new rights-of-way, however, will be required.

The SCE and SDG&E transmission lines will each be supported by two steel horizontal portal structures (Fig. 3.9) for the initial 0.6 km (0.4 mile) of right-of-way northeast of the SONGS switchyard. These structures will replace the steel lattice towers now supporting the existing circuits in this area. No additional land for tower bases or access roads will be required.

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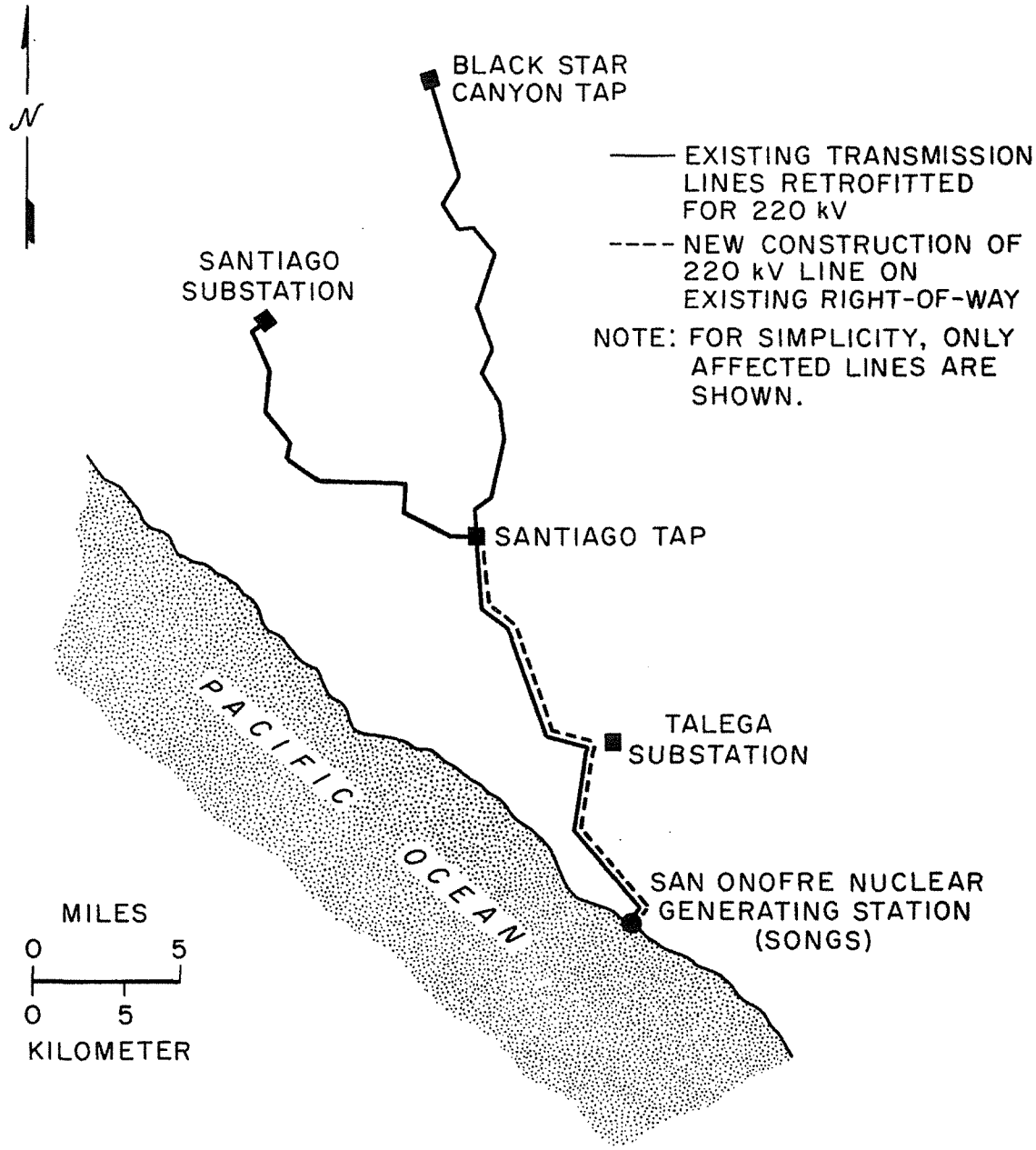

Fig. 3.7. Schematic diagram of proposed Southern California Edison Company transmission lines for SONGS 2 & 3.

3.2.5.1 SCE transmission lines

A double circuit 220-kV transmission line will be constructed between SONGS and Santiago Tap, an approximate distance of 24.3 km (15.1 miles) (Fig. 3.7). About 73 steel lattice towers (Fig. 3.10) will be required for this line, with an average span of about 335 m (1100 ft) between towers. The average tower height is estimated to be 39.6 m (130 ft). The new tower bases will require 2.44 ha (6.03 acres), and access road extensions are expected to require 1.32 ha (3.25 acres) of land (ER, Suppl. 2, Item 36). Additional transmission lines required by SCE that were not discussed in the FES-CP are those from SONGS to Santiago Tap, Santiago Tap to Santiago Substation, and Santiago Tap to Black Star Canyon Tap. These lines, totaling

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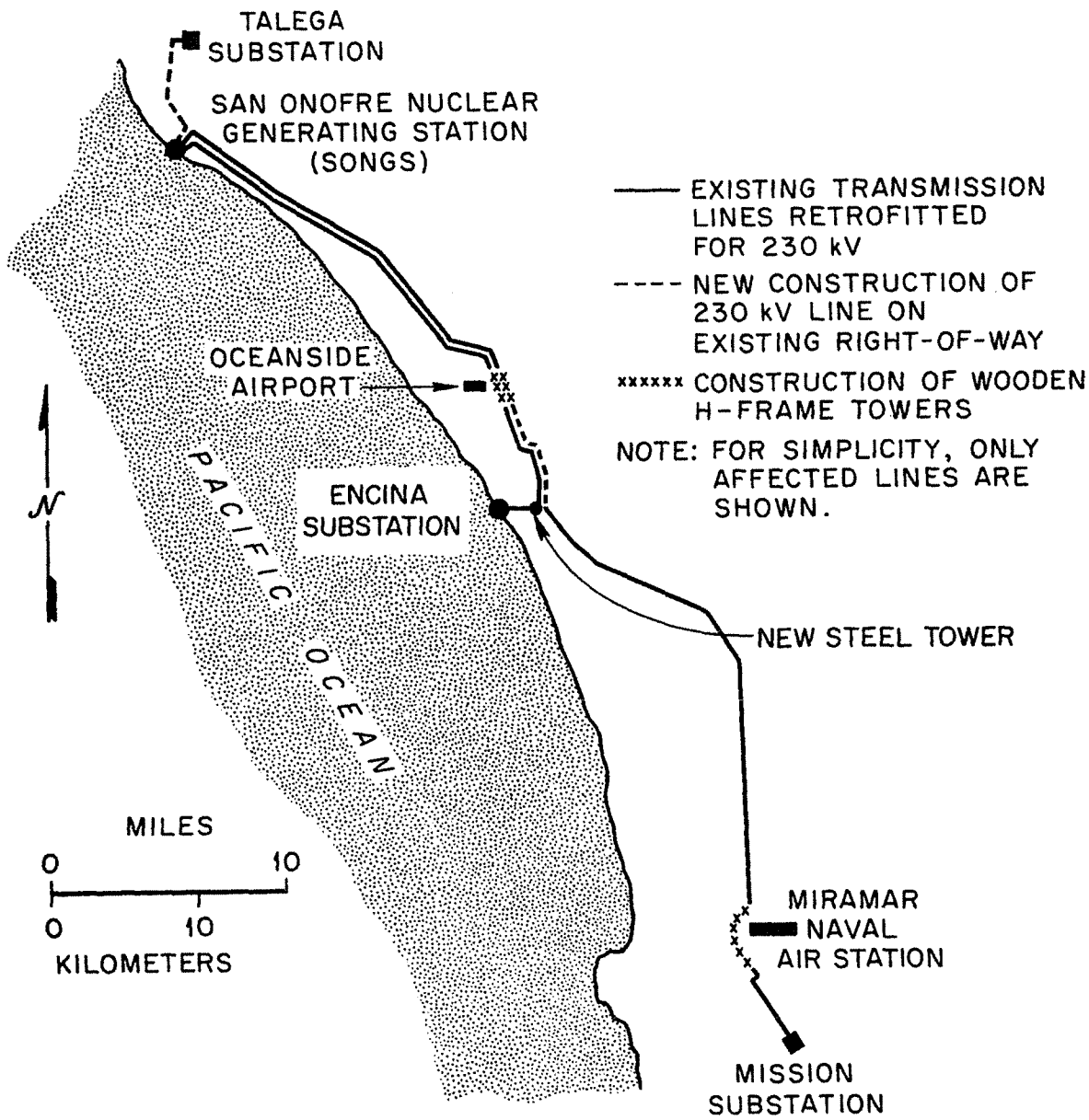
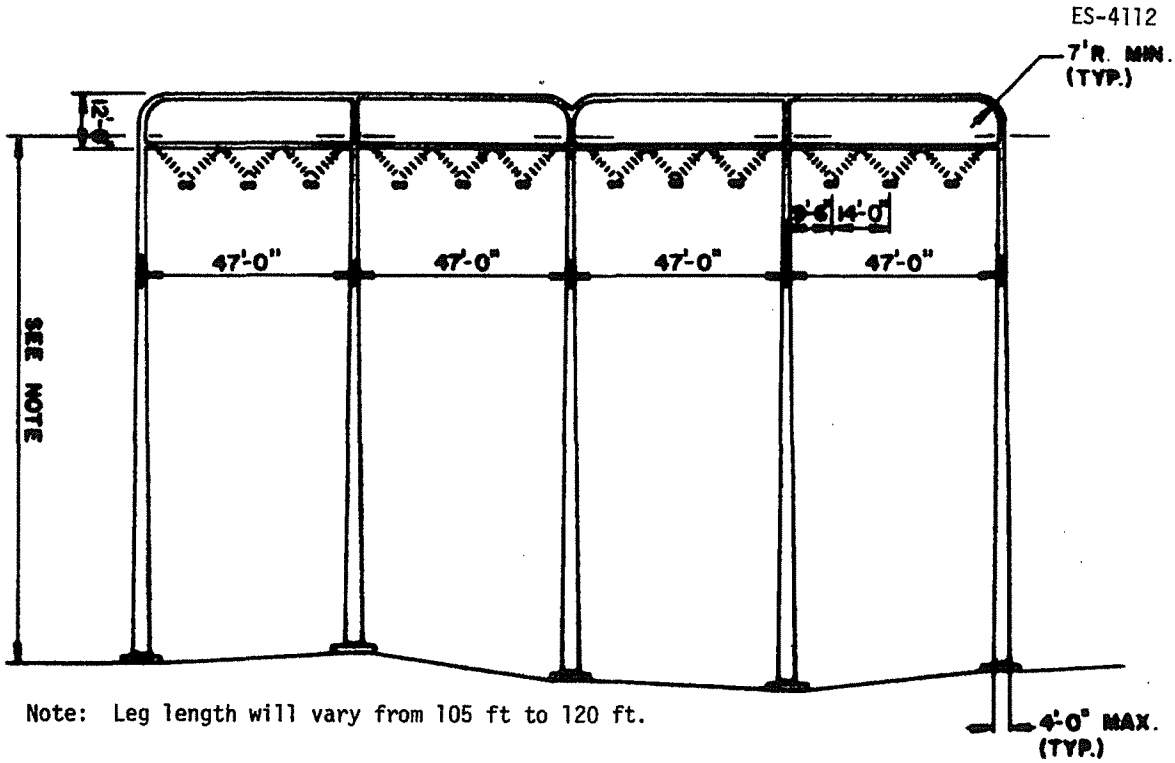


Fig. 3.8. Schematic diagram of proposed San Diego Gas and Electric Company transmission lines for SONGS 2 & 3.

71.7 km (44.2 miles) will be retrofitted to operate at 220 kV. Retrofitting will involve the replacement of existing conductors with larger ones (on existing towers) and the construction of four additional towers between Santiago Tap and Black Star Canyon Tap.[4] These towers are required to provide adequate ground clearance in some spans where the wire tension will have to be reduced from its present value (ER, Sect. 3.9.1.1). This additional construction is expected to require 0.13 ha (0.33 acres) of land for new tower bases and 0.52 ha (1.3 acres) for access road extensions (ER, Suppl. 2, Item 36).

The material storage yard for SCE transmission lines will be located about 1.6 km (1 mile) north of the San Onofre Nuclear Generating Station within Camp Pendleton Marine Base. The area involved will be about 2.2 ha (5.5 acres) and will not require any clearing or opening of new roads (ER, Suppl. 2, Item 30).



Note: Leg length will vary from 105 ft to 120 ft.

Fig. 3.9. Four-circuit steel horizontal portal structures used by Southern California Edison Company; San Diego Gas and Electric Company will use a similar structure with five circuits. Source: ER, Fig. 3.9-2.
(To convert ft to m, multiply by 0.3048.)

3.2.5.2 SDG&E transmission lines

The only transmission line required by SDG&E that was not discussed in the FES-CP will run between SONGS and Mission Substation, a distance of 85 km (53 miles) (Fig. 3.8). This line will be installed by adding a 230 kV circuit to the vacant position on existing double circuit towers;[1] some of the existing towers will be replaced. A total of about 36 wooden H-frame towers (Fig. 3.11) will be constructed along a 1.6-km (1-mile) segment east of Oceanside Airport and a 6.8-km (4.2-mile) segment opposite Miramar Naval Air Station to accommodate FAA regulations.[1] About 9 km (5.6 miles) of existing 138 kV wood structures south of the Oceanside Airport will be replaced by approximately 32 double circuit steel lattice towers (Fig. 3.12). The construction of the new towers for this line will not require any additional land for tower bases or access roads (ER, Suppl. 2, Item 36). Subsequent to issuance to the FES-CP, additional information was supplied by the applicant regarding the line from SONGS to Encina Substation and SONGS to Talega Substation. The line from SONGS to Encina Substation, 40 km (25 miles), will be formed by adding a 230 kV circuit to the vacant position on existing double circuit towers.[1] In addition, approximately four wooden H-frame towers (Fig. 3.11) will be constructed along a 1-km (0.6 mile) segment east of Oceanside Airport to accommodate FAA regulations. To facilitate arrangement of the new conductors, a single steel tower will also be installed east of Encina Substation. All new structures will be constructed within existing rights-of-way and will not require any additional land for tower bases or access roads (ER, Suppl. 2, Item 36). The line from SONGS to Talega Substation traverses about 11.3 km (7 miles) and will require construction of about 32 steel lattice towers (Fig. 3.12). The new tower bases will require about 0.23 ha (0.58 acre), and access road extensions are expected to require 0.53 ha (1.3 acres) of land (ER, Suppl. 2, Item 36). Because SDG&E's original plan assumed that the Talega Substation would be constructed and in operation prior to completion of SONGS 2 & 3 (ER, Suppl. 2, Item 25), this facility was discussed in the FES-CP as if it were already in existence. Construction, however, was delayed. The proposed Talega Substation is expected to cover 2 ha (5 acres) of land; an additional 2 ha (5 acres) around the substation will also require grading.

The material storage yard for SDG&E transmission lines will be located in existing substations with the following exceptions: (1) fencing a level area of about 0.09 ha (0.23 acre) adjacent

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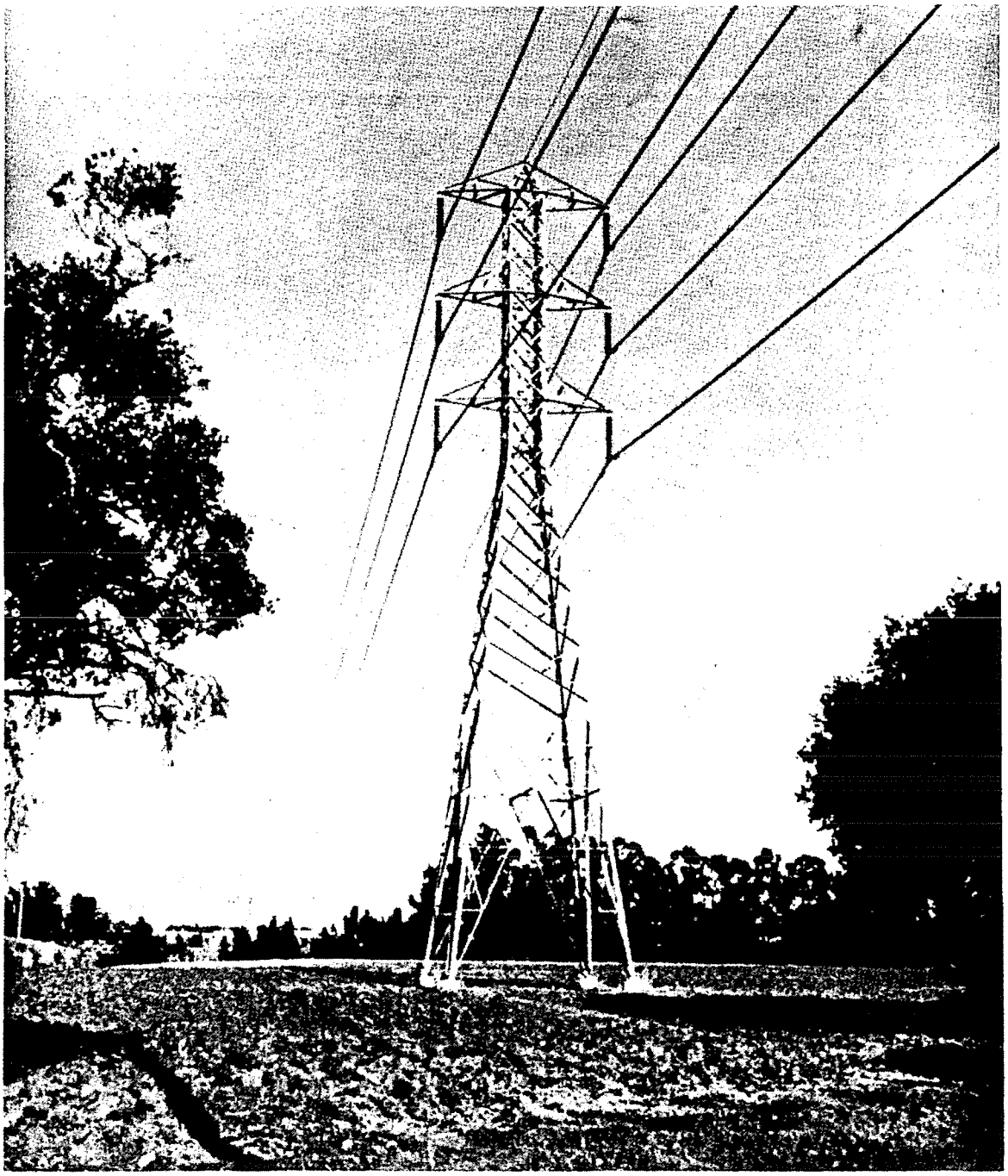

Fig. 3.10. Typical steel lattice tower design used by Southern California Edison Company. Source: ER, Fig. 3.9-3.

to the existing Pulgas Substation and (2) fencing a level area of about 0.09 ha (0.23 acre) adjacent to the Japanese Mesa Substation. No grading, clearing, or additional access roads are anticipated for this project (ER, Suppl. 2, Item 30).

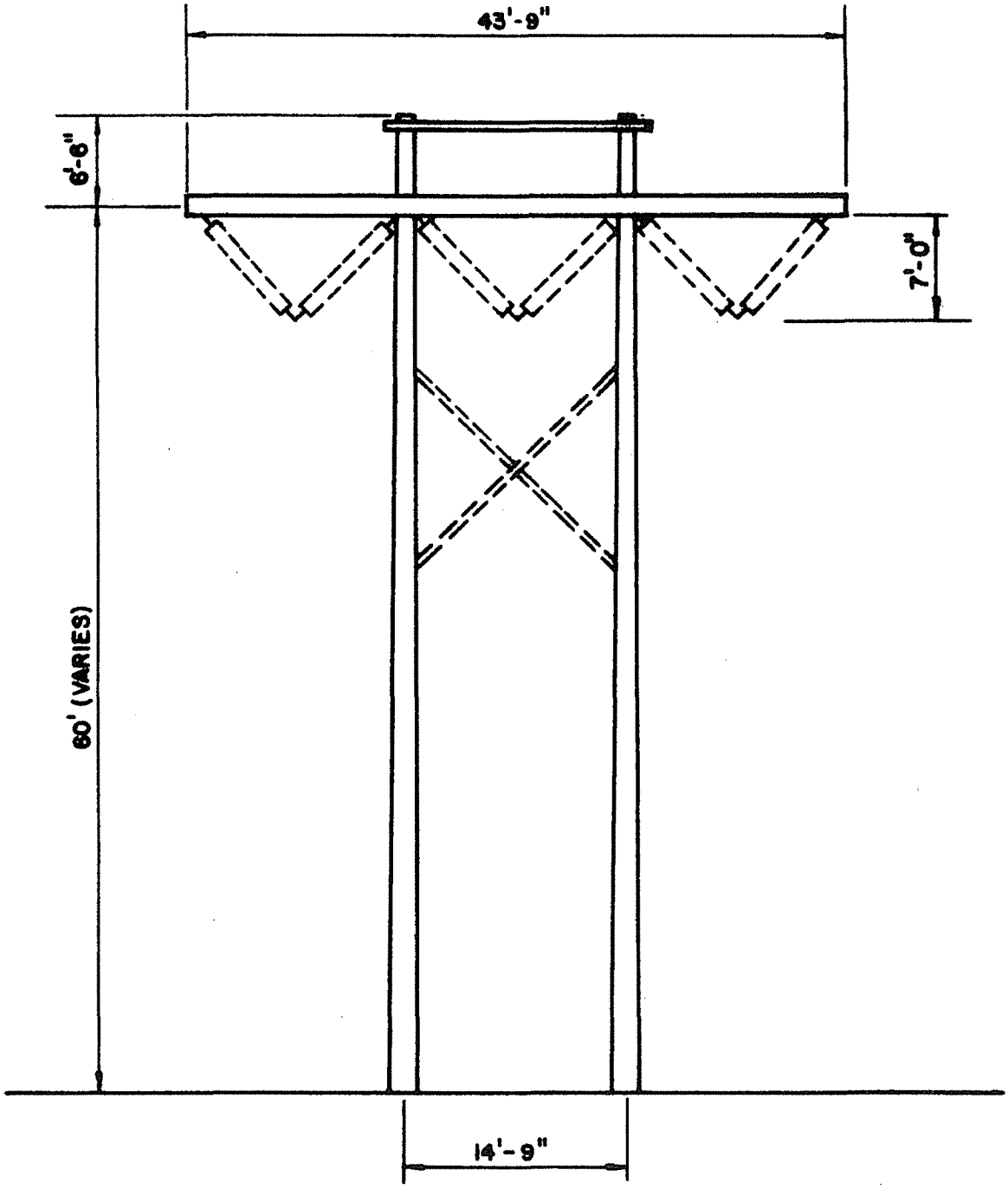

Fig. 3.11. Wooden H-frame tower used by San Diego Gas and Electric Company. Source: ER, Fig. 3.9-9.(To convert ft to m, multiply by 0.3048; to convert in. to mm, multiply by 25.4.)

3.2.6 Probable maximum flood berm

3.2.6.1 Description of structure and existing environment

Subsequent to issuance of the FES-CP the applicant was required to construct an earthern berm to protect the Station form the probable maximum flood (PMF). Construction of this structure

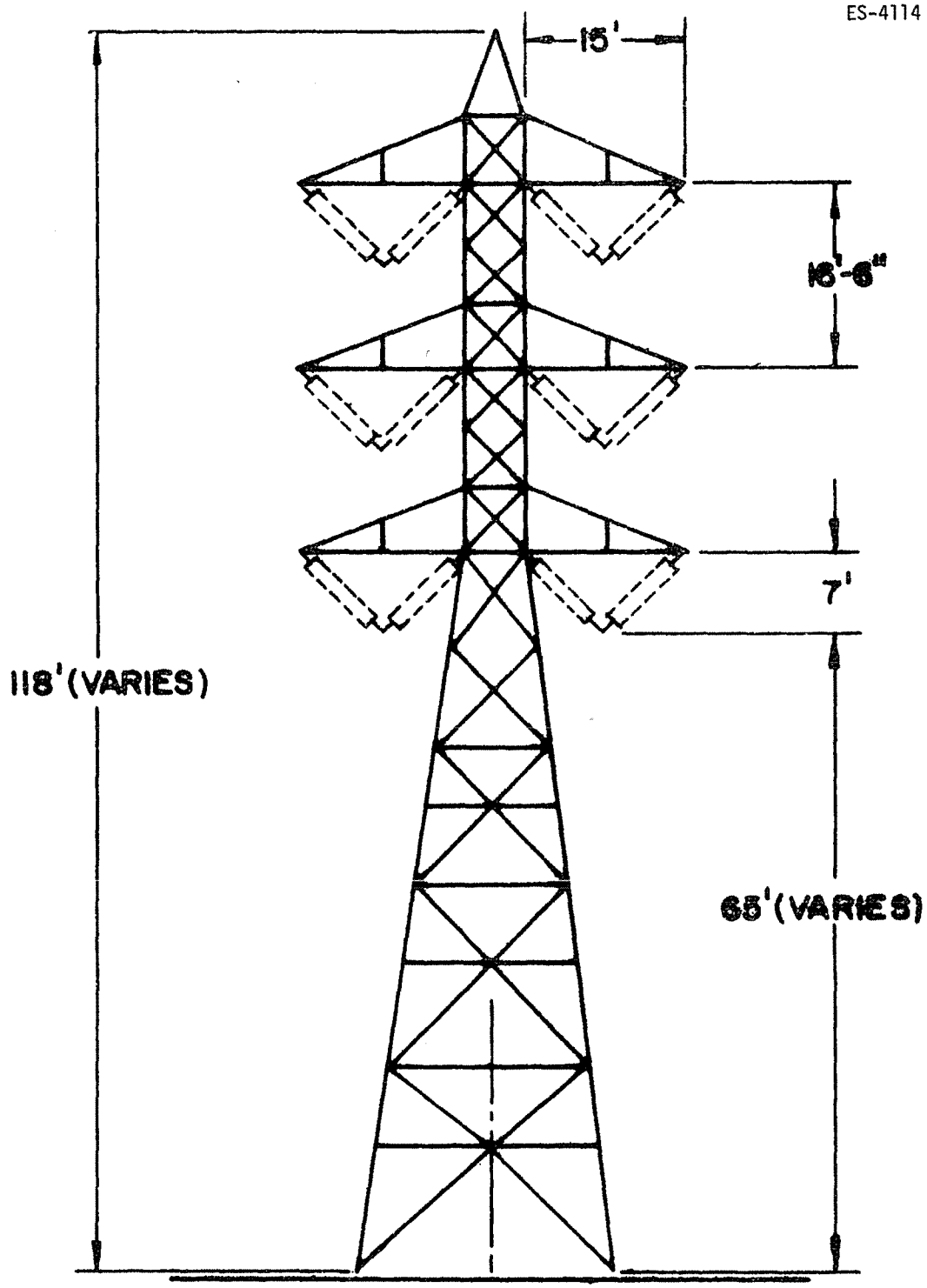

Fig. 3.12. Typical steel lattice tower design used by San Diego Gas and Electric Company. Source: ER, Fig. 3.9-8.(To change ft to m, multiply by 0.3048.)

and associated environmental impacts are presented by the applicant in a letter to the NRC[5] and in the applicant's final safety analysis report (FSAR).

The San Onofre site is located on a coastal plain at the base of the western foothills of the Santa Margarita Mountain Range. Elevation in this area rises sharply from sea level to a fairly level terrace formation 30 to 61 m (100 to 200 feet) above sea level. About 450 m (1500 feet) inland the foothills begin, rising with moderate slopes to an elevation of about 900 m (3000 ft) above sea level. Natural plant cover in the coastal plain typically consists of coastal chaparral and grassland, while in the foothills it is composed primarily of chaparral and open woodland.

There are no perennial streams in the general vicinity of the plant site. However, ephemeral streams and water courses do exist. The major streams are San Mateo Creek, located about 3.2 km (2 miles) to the northwest and San Onofre Creek located approximately 1.6 km (1 mile) to the northwest. The drainage divide separating San Mateo and San Onofre Creeks precludes the plant site from being influenced by San Mateo Creek. The applicant's results of the probable maximum flood (PMF) analysis concluded that the San Onofre Creek Basin exhibits no flooding potential to the site (FSAR, Sect. 2.4.2.2). Topographical features of the basin would contain the maximum flood stage and thereby preclude flooding of the site by this source. The foothill drainage basin, however, does contribute to the hydrologic factors influencing the plant site. The basin totals 2.2 km^2 (0.86 mi^2). There are no gaging stations located within the basin and, consequently, stream flow records are not available.

The entire watershed of the foothill drainage basin lies within the boundaries of the Marine Corps Base, Camp Pendleton. Elevation of the basin varies between 30 to 365 m (100 to 1200 feet) above sea level. Ground slope varies from 8 to 22%. Ground cover is moderate, consisting mainly of chaparral and grassland.

Water control structures at the foot of this basin consist of the 107- and 183-cm (42- and 72-in.) diameter concrete culverts under I-5. The capacity of these culverts is 5.1 and 14.7 m^3/sec (180 and 520 ft^3/sec), respectively. In addition to the two culverts, an earthern channel traverses the basin along the east side of I-5 diverting runoff to San Onofre Creek. The capacity of the channel is 52.4 m^3/sec (1850 ft^3/sec).

The applicant's analysis of the flooding potential of the foothill drainage area indicated that the plant site could be subjected to flooding during the occurrence of the PMF. In order to preclude flooding of the site by this source a diversion structure routes the surface runoff from the foothill drainage area to the San Onofre Creek Basin. This PMF structure will be an earthern berm, having an isoceles trapezoid cross section that is 2.4 m (8 feet) high and 12.8 m (42 feet) wide at its base, with 2:1 side slopes. The berm will parallel I-5 and will be 2.7 km (1.68 miles) long. The existing channel which parallels the proposed berm will be widened where necessary and will vary from 7.6 to 30.5 m (25 to 100 ft) in width. The berm will cover a portion of an existing road, El Camino Real Road, requiring the construction of a new road. The relocated road will run approximately parallel to and east of the proposed PMF berm.

Relocation of the road will require about 1.4 ha (3.5 acres) of land, the berm will cover approximately 3.5 ha (8.6 acres), and the channel (assuming a 30 m (96 ft) width) will require about 8.3 ha (20.6 acres) for a total land area requirement of 13.2 ha (32.7 acres). The existing channel and El Camino Real Road are included in this acreage.

A terrestrial biological survey of the site was conducted on October 25 and 31, 1977. Vegetation on the site is basically a southern coastal sage scrub community, being influenced by the coastal marine climatic conditions. However, nearly half of the site (northern portion) has been previously disturbed as evidenced by the presence of many non-native "weedy" species including saltbush (Atriplex semibaccata), Russian thistle (Salsola kali), mustard (Brassica geniculata) tree tobacco (Nicotiana glauca), and sow thistle (Sonchus oleraceus). Native species on this area include California sagebrush (Artemesia californica), California buckwheat (Eriogonum fascilculatum), and coyote brush (Baccharis pilularis). The southern half of the site is primarily vegetated with native species of the coastal sage scrub plant community including the native species listed above. The land on which the El Camino Real Road will be relocated contains many of the same species that occur at the berm site, but with a higher degree of cover.

Fauna surveys of the site and vicinity demonstrated that the majority of the species present were birds (24 species). Red-tailed hawks (Buteo jamaicensis) were prevalent in the vicinity using wooden posts, telephone and power poles as perches and a SCE lattice transmission tower for nesting. Although only 2 species of reptiles and 2 species of mammals were observed, others are likely to occur in the vicinity.

No threatened or endangered flora or fauna were observed on the proposed PMF Berm site, the area to be cut, or on the area where the El Camino Real Road is to be relocated.[5]

On November 14, 1977, an onsite inspection of the alignments of both the proposed berm and access road was conducted to determine the presence or absence of surficial paleontologic

values.[5] Although the survey did not result in locating any fossils, a review of the literature revealed that all sedimentary formations in the vicinity contain fossils. No localities in the immediate area have been placed on the National Registry of Natural Landmarks.

The site was surveyed for archaeological resources on December 8, 15, and 16, 1977 (ref. 5). The northern third of the berm was not surveyed because it had previously been studied; some portions of the berm also were not adequately surveyed because of dense vegetation.[5] In one area, eight pieces of marine shell were observed. The shells, however, were weathered and worn and gave the appearance of paleontological specimens, rather than archaeological remains.[5] An archaeological map and literature search revealed four recorded archaeological sites within 1.6 km (1 mile) of the proposed project, but none were located within the project area.[5]

3.2.6.2 Impacts of PMF berm

The berm will be built on top of an existing asphalt road. Consequently disruption of this area will have no significant biological impact. Widening the existing channel which parallels the proposed berm will require loss of about 8.5 ha (21 acres), and an additional 1.4 ha (3.5 acres) of habitat will be lost due to relocation of El Camino Real Road. Because these habitats do not represent unique communities, loss of this relatively small acreage should have no significant impact to biological resources of the area. To minimize the impact to raptors nesting in the vicinity the applicants will attempt to avoid construction activity during the period of March and April.[5]

The construction of the PMF berm might physically destroy fossils and/or relationships between fossils, or the environmental context of original deposition, that could provide significant paleontological data. In addition, the berm and new road may cover deposits containing significant paleontological data thereby making such data unreachable. To mitigate these potential impacts the applicants will conduct a paleontological survey prior to construction and monitor the excavation as it proceeds.[5] This will allow fossils to be salvaged as they are unearthed. Construction should be phased so that equipment could be shifted to other areas if fossils were located. Sufficient time should be allowed to uncover, record, and remove the fossils. If excavation were initiated in areas of highest paleontological potential, equipment could be moved to areas of low potential if paleontological values were encountered. This would provide a maximum amount of construction time and a maximum amount of time for paleontologic resource recovery.

Construction of the proposed PMF berm should not cause any direct or indirect adverse impact to known archaeological resources. However, the site would have been a favorable area for aboriginal habitation; i.e., an area of relatively flat topography with abundant fresh water and food resources.[5] The probability exists that buried resources may be in the area, especially where dense vegetation obscures the surface. Consequently, a trained archaeologist will monitor the construction activity and take appropriate conservation measures if necessary.[5]

No significant commitments of resources will result from construction and maintenance of the PMF Berm. The possibility exists that potential archaeological or palcontological resources would be destroyed during the excavation activity required for construction of the berm. However, if the proper mitigation measures are performed (monitoring, analysing, interpretating, preserving, and reporting), then these resources would not be irretrievable.

3.2.6.3 Floodplain management

The objective of Executive Order 11988, "Floodplain Management," is ". . . to avoid to the extent possible, the long- and short-term adverse impacts associated with the occupancy and modification of floodplains and to avoid direct and indirect support of floodplain development whenever there is a practicable alternative." The Construction Permit was issued and the majority of construction completed prior to issuance of the Executive Order. Thus we conclude that no practicable alternative locations exist. The following is a discussion of floodplain conditions prior to construction of the plant and alterations made to these floodplains as a result of construction of San Onofre Units 2 and 3.

The San Onofre Units 2 and 3 are bounded on the east by Interstate Highway 5, the Atchison Topeka and Santa Fe Railroad and Highway 101. Interstate Highway 5 was constructed in 1968 prior to San Onofre Units 2 and 3. As part of the I-5 construction, a drainage channel designed for 100-year storm runoff was constructed parallel to and east of I-5. This channel intercepted tributary rainfall runoff from the foothills east of I-5 and transported it to the north away from the plant. The channel then merged with San Onofre Creek which in turn flowed to the Pacific Ocean.

The plant site which is bounded on the west by the Pacific Ocean was originally on a high coastal bench approximately 100 feet above sea level. Located at this elevation, the site was protected from severe flooding events and thus was not in the 100-year ocean floodplain.

The existing drainage channel which is west of and parallel to I-5, is being enlarged to contain floods and debris. The design capacity of the channel enlargement and extension is the Probable Maximum Flood, an event which is greater than the one-percent chance flood. The improvement will not induce higher flood stages.

The San Onofre plant grade is lower than the original coastal bench. However, construction of a seawall on the seaward side of the plant and east of the original bluff line provides protection from events larger than the one percent chance flood.

The plant, including the intake structure and seawall, is not built in the 100-year floodplain and will not be flooded by any 100-year flood levels. The intake crib and intake and discharge conduits are submerged on the ocean floor. The channel improvement east of Interstate Highway 5 will not increase flood levels. Therefore, the construction and operation of the San Onofre Unit 2 and 3 Nuclear Generating Station will comply with the intent of Executive Order 11988.

3.2.7 Emergency facilities

Emergency plans for San Onofre Units 2 and 3 call for an onsite Technical Support Center adjacent to the control room and an interim onsite Operational Support Center in the lunch room of the administration, warehouse, and shop building. Neither requires changes in the structural design or layout of the facility. An offsite Emergency Operations Facility is tentatively planned to be constructed on Japanese Mesa, east of Interstate 5, within the Camp Pendleton Reservation. This area was used for disposal of excavated material during construction. The structures must be designed to accommodate a minimum of 35 people.

REFERENCES

1. U.S. Nuclear Regulatory Commission, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low as Practicable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," May 5, 1975, and as amended Sept. 4, 1975, and Dec. 17, 1975, in Title 10, "Code of Federal Regulations," Part 50, Appendix I.

2. U.S. Nuclear Regulatory Commission, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWR-GALE Code)," NUREG-0017, April 1976.**

3. U.S. Nuclear Regulatory Commission, "Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors," in Regulatory Guide 1.110, March 1976.**

4. Letter from Ira Thierer, Southern California Edison Co., to Dr. Knox Mellon, State Historic Preservation Officer, June 2, 1978.*

5. Letter from J. G. Haynes, Southern California Edison Co., to W. H. Regan, Jr., USNRC, undated, docketed on February 18, 1978.*

*Available for inspection and copying for a fee in the NRC Public Document Room, 1717 H St., N.W. Washington, DC 20555.

**Available from the NRC/GPO Sales Programs, Washington, DC 20555 and from the National Technical Information Service, Springfield, VA 22161.

4. STATUS OF SITE PREPARATION AND CONSTRUCTION

4.1 RESUME AND STATUS OF CONSTRUCTION

As of December 1980, the construction of SONGS Unit 2 was 97% complete, and SONGS Unit 3 was 68% complete. Figure 4.1 is a recent photograph of the site.

Impacts of construction have been identified in the FES-CP. The major terrestrial impact has been the excavation of about 16.4 ha (40.5 acres) of the San Onofre Bluffs, which resulted in the loss of a small amount of wildlife habitat. No rare or endangered animal species in the vicinity of the site have been or are expected to be adversely affected by construction activities.

The environmental impacts associated with changes in the routing of transmission lines subsequent to issuance of the FES-CP have been evaluated by the staff in its environmental impact appraisal regarding extension of the earliest and latest construction completion dates.

4.2 Offsite Emergency Operations Facility

An offsite Emergency Operations Facility is tentatively planned to be constructed on Japanese Mesa, east of Interstate 5, within the Camp Pendleton Reservation. This area was used for disposal of excavated material during construction. The structure must be designed to accommodate a minimum of 35 people. Construction of the Emergency Operations Facility on Japanese Mesa will not significantly disturb the area relative to previous disturbances.

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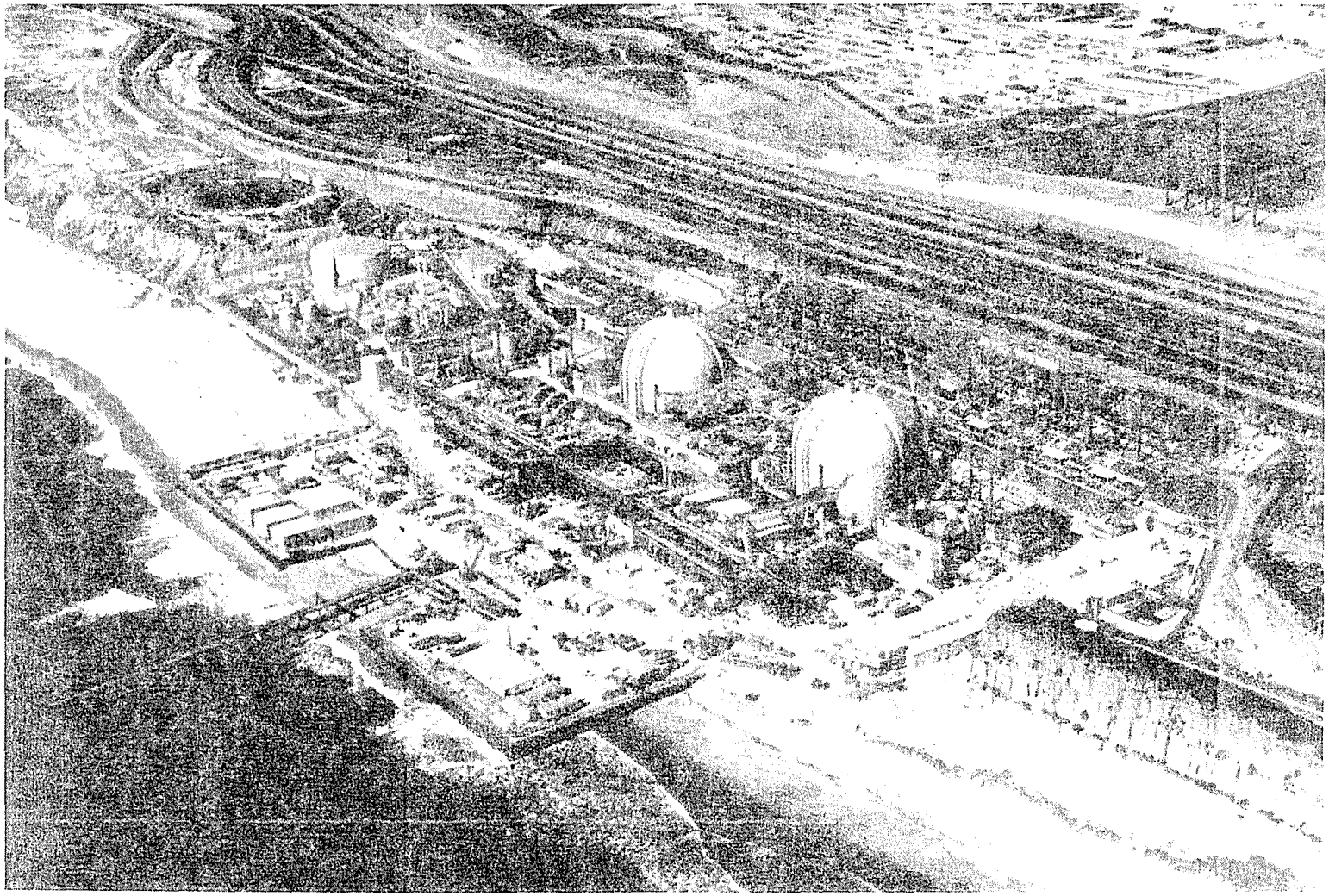

Fig. 4.1. Photograph of San Onofre Nuclear Generating Station taken in October 1980.

5. ENVIRONMENTAL EFFECTS OF STATION OPERATION

5.1 RESUME

The major design changes that have environmental effects involve the heat dissipation system. A more thorough analysis by the staff of the thermal plume is described in Sect. 5.3.1.2. The effects of the revised thermal-plume analysis on aquatic biota are discussed in Sect. 5.4.2.1. Changes in the effects of chemical effluents are discussed in Sects. 5.3.2 and 5.4.2.2. A revised discussion of radiological impacts is given in Sect. 5.5. Sect. 5.6 contains a revised assessment of the socioeconomic impacts.

5.2 IMPACTS ON LAND USE

Although the transmission line routes have been modified since the issuance of the construction permit (Sect. 3.2.5), the analysis of projected impacts as set forth in the FES-CP (Sect. 5.1) remains valid. All new transmission lines will be constructed on existing rights-of-way; a total of 5.2 ha (12.8 acres) of land will be required for access road extensions and for new tower bases.

The operation of SONGS 2 & 3 is not expected to affect any existing or proposed areas of the National Park System nor any existing or known potential sites to be listed as national landmarks.[1] In 1980, the applicant conducted a National Register assessment program of the 230 kV transmission right-of-way from San Onofre Nuclear Station to Black Star Canyon and Santiago Substation and to Encina and Mission Valley Substation and evaluated 41 previously identified archaeological sites. As a result of this effort, the NRC, in consultation with the State Historic Preservation officer, is seeking a determination of eligibility for inclusion in the National Register of Historic Places for 23 sites (see Appendix D, letter from Dr. Knox Mellon, State Historic Preservation officer, to D. C. Scaletti, USNRC, dated December 18, 1980). The staff agrees with the conclusions of the December 18, 1980, letter and will seek concurrence of determinations of effect from the Advisory Council on Historic Preservation.

5.3 IMPACTS ON WATER USE

5.3.1 Thermal discharges

5.3.1.1 Applicant's thermal analysis

The applicant retained the California Institute of Technology to perform a thermal analysis for the purpose of modifying the diffuser design in order to ensure compliance with state thermal standards. To accomplish this, a physical hydraulic model study was carried out at the W. M. Keck Laboratory of Hydraulics and Water Resources. The culmination of this effort was the diffuser design and configuration described in Section 3.2.2.

The physical model simulation was performed in a basin having horizontal dimensions of 11 m (36 ft) by 6 m (20 ft) which represents a prototype modeled region of about 8500 m (28,000 ft) by 4900 m (16,000 ft). The location and orientation of the Units 2 and 3 model intakes and diffusers within the basin are illustrated in Fig. 5.1. The bottom of the basin was filled with sand which was shaped to produce a simplified representation of the San Onofre bathymetry. The resulting bottom geometry was uniform in the longshore direction and varied as a composite of linear slopes in the offshore direction, as shown in Fig. 5.2. In order to satisfy scaling laws, the number of ports per laboratory diffuser was 16.

To perform simulations, the basin was filled with water at a constant temperature, then water at a temperature 16.67°C (30°F) higher was discharged through the diffusers. This excess temperature was required to maintain proper similitude and represents a 11.1°C (20°F) prototype excess temperature. Water was withdrawn from the basin through the intakes; however, this water was not recirculated. The model basin had the capability to simulate a variety of longshore current regimes, and among those investigated were no crossflow, crossflows of various amplitudes, reversing flows of various amplitudes, and special currents. The results of the simulations are summarized in the ER, Table 5.1-1. Among

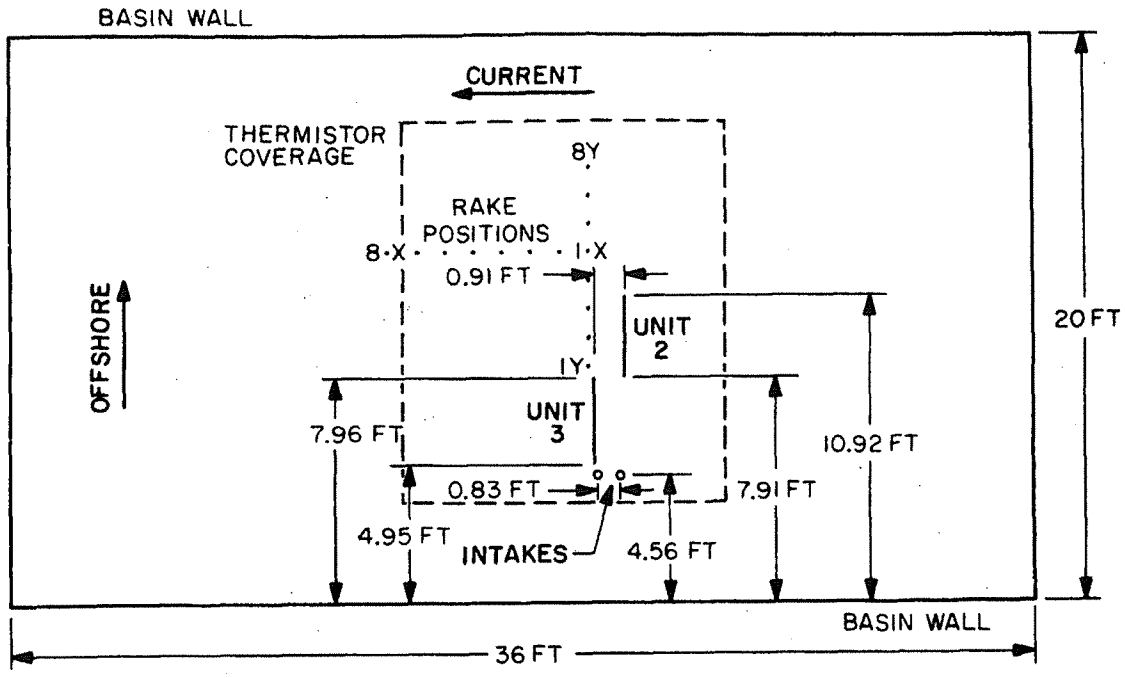

Fig. 5.1. Layout of basin used for the physical model study. Source: R. C. Y. Koh, N. H. Brooks, E. J. List, and E. J. Wolanski, *Hydraulic Modeling of Thermal Outfall Diffusers for the San Onofre Nuclear Power Plant*, W. M. Keck Laboratory of Hydraulics and Water Resources, California Institute of Technology, Report KH-R-30, January 1974, Fig. 6.1.
(To change ft to m, multiply by 0.3048.)

these simulations, the worst case was that of zero crossflow. A plot of surface isotherms produced by the model for this case is given in Fig. 5.3. Further details of the physical-model study can be found in ref. 2. There are, however, certain physical conditions and mechanisms that could not be properly modeled in the laboratory. In an effort to account for this limitation on modeling, the modelers associated a probable temperature excess with each uncertainty. The total of these individual uncertainties was 0.83°C (1.5°F). It was therefore reasoned that state thermal standards should be met if the laboratory results satisfied these standards for 1.39°C (2.5°F), with the 0.83°C (1.5°F) margin of error, rather than 2.2°C (4.0°F).

It is evident from Fig. 5.3 that this case satisfies the state thermal standards. The applicant suggests that this is the worst case and, therefore, concludes that SONGS 2 and 3 will, under all conditions, comply with California State thermal standards.

The staff has reviewed the applicant's thermal analysis and believes that the physical model does not adequately represent certain hydrodynamic mechanisms and certain physical features of the prototype. The most significant of these is the duration of the physical model simulation. The staff believes that the physical model simulation, which yielded the result given in Fig. 5.3, has not reached thermal equilibrium. This is apparent in the applicant's results for surface excess temperature versus time given in Fig. 5.4. The upper curve represents the maximum surface temperature as a function of time anywhere in the basin, while the lower curve represents the maximum surface temperature as a function of time beyond 305 m (1000 ft) from the discharge point. The time scale for thermal equilibrium in the upper curve is a function of the time required for the heated water from the discharge to reach the surface and, therefore, should be relatively short. The staff has substantiated this by performing a least-squares curve fit on the data shown in the upper curve. The results show that the maximum surface excess temperature anywhere in the basin is increasing less than 0.028°C (0.05°F) per day. This is small compared with the standard deviation of the curve fit and, therefore, thermal equilibrium can justifiably be assumed. Beyond 305 m (1000 ft) from the discharge, the thermal equilibrium time scale will be a function of the rate of transport of heated water by densimetric effects and diffuser momentum away from the discharge point. This time scale should be longer than that for thermal equilibrium near the discharge. A similar curve fit performed on the lower plot reveals that the excess surface temperature beyond 305 m (1000 ft) from the discharge is increasing by approximately 0.16°C (0.29°F) per day. The staff believes that such a time-rate-of-change of temperature does not represent thermal equilibrium. Using a mathematic model, the staff has qualitatively reproduced the applicant's results. However, this mathematical simulation demonstrates that for increased

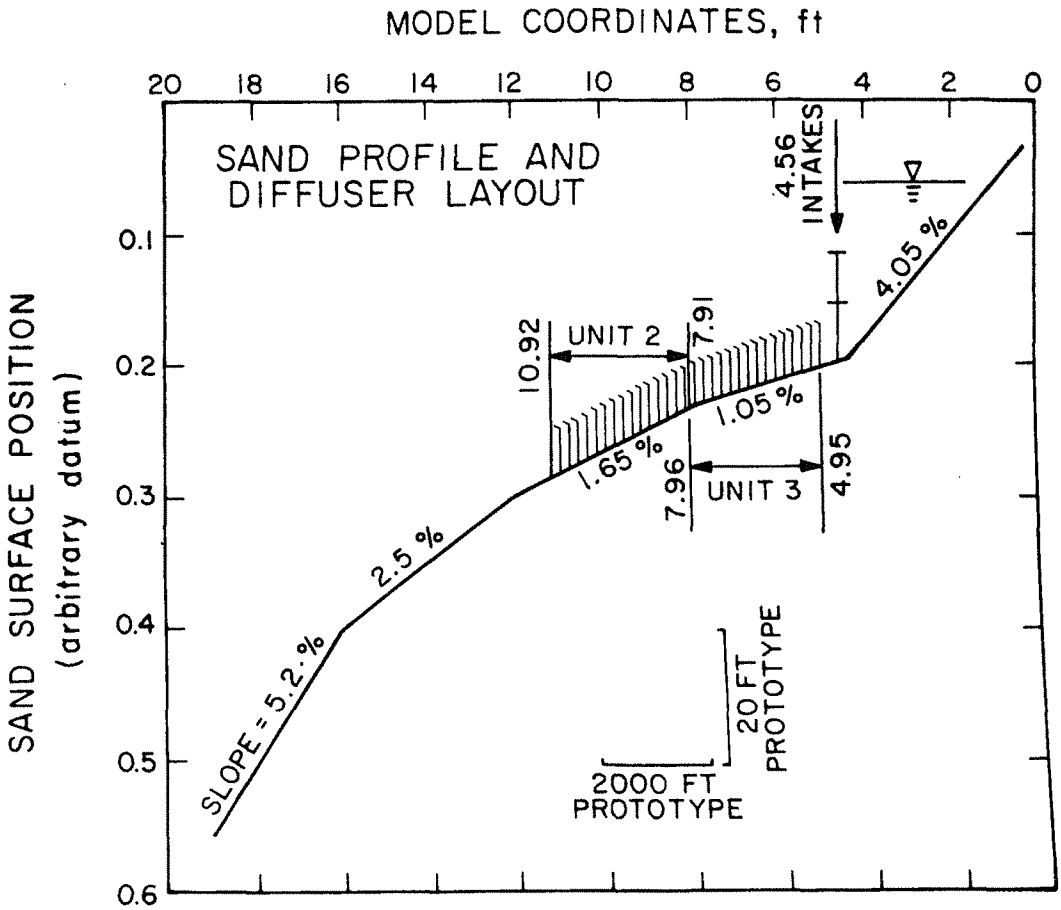

Fig. 5.2. Bottom profile used for the physical model study. Source: R. C. Y. Koh, N. H. Brooks, E. J. List, and E. J. Wolanski, "Hydraulic Modeling of Thermal Outfall Diffusers for the San Onofre Nuclear Power Plant," W. M. Keck Laboratory of Hydraulics and Water Resources, California Institute of Technology, Report KH-R-30, January 1974, Fig. 6.2. (To change ft to m, multiply by 0.3048)

duration of the simulation, there is a substantial increase in the predicted excess temperatures. In fact, for the conditions represented in Fig. 5.3, an increase in simulation time would likely have resulted in predicted excess temperatures that violate state thermal standards. However, such a prediction is unimportant because the particular simulation then represents conditions so unrealistic that the results become irrelevant.

Although the problem of underprediction is inherent in all the applicant's results, it is less significant for the realistic cases. For conditions more realistic than those in Fig. 5.3, the predicted excess temperatures are sufficiently low so that no violations of thermal standards would be expected as a result of increases of simulation duration in the physical model. This expectation is confirmed by the staff's mathematical model study.

5.3.1.2 Staff's thermal analysis

The staff has performed an independent thermal analysis for the proposed operation of the once-through cooling system. Depth-averaged numerical models from the Unified Transport Approach[3] were used to simulate plant-induced flows, natural flow, and water temperatures. Predictions have been made for conditions typical of mid-July, since this is the time of year when thermal impacts should be the most severe. The modeled region is a rectangle measuring approximately 24,000 m (80,000 ft) in the longshore direction and approximately 12,000 m (40,000 ft) in the offshore direction. This region with the numerical grid system superimposed is shown in Fig. 5.5.

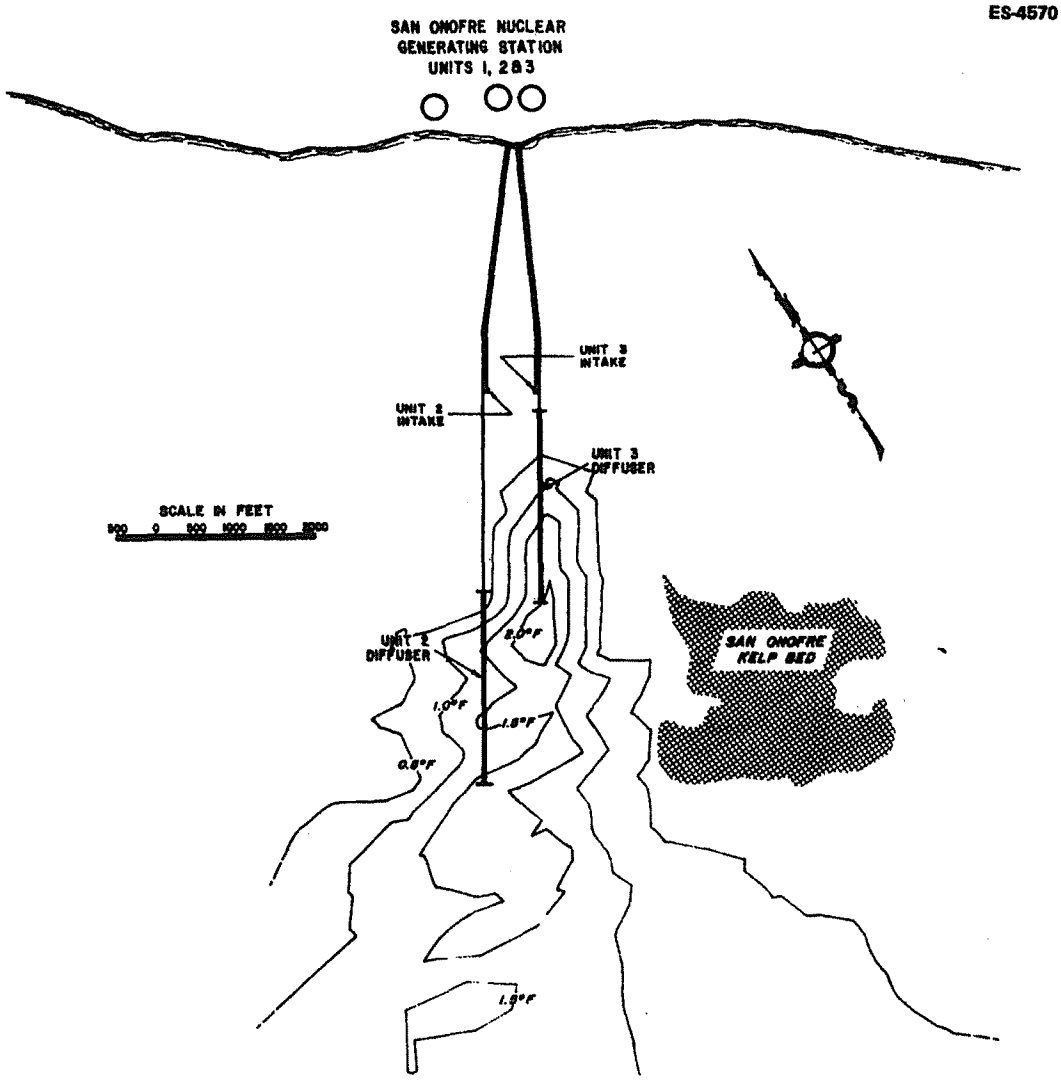

Fig. 5.3 Excess temperature at the surface predicted in the physical model study, for the case of no ambient flow. Source: ER Fig. 5.1-1. (To change ft to m, multiply by 0.3048; to change F° to C°, divide by 1.8.)

One numerical model was used to generate the induced flow from intakes and discharges from all three units. In this model, the intakes are represented as point sinks and the Unit 1 discharge is represented as a point source. The diffusers for Units 2 and 3 are each represented as a superposition of five jets. The hydrodynamics of each jet is modeled using a uniformly valid singular-perturbation theory, numerically corrected for bathymetry. The individual flows from the three intakes and discharges were summed to generate a total plant-induced flow field, as shown in Fig. 5.6.

A quasi-potential hydrodynamic model was used to generate the magnitude and direction of the natural currents and free surface displacement resulting from two tidal components and a net downcoast drift, at each grid element. The open-water boundary conditions were adjusted to produce flows which are consistent with observed data[4-7] from current meters and drogues. Three individual runs were executed, one for each of the two tidal harmonics (a 12.4 hr period and a 24.8 hr period), and a third to generate the drift current. These three flow components were combined, with the appropriate phase relationships, to produce a simulation of the natural flow field during mid-July conditions.

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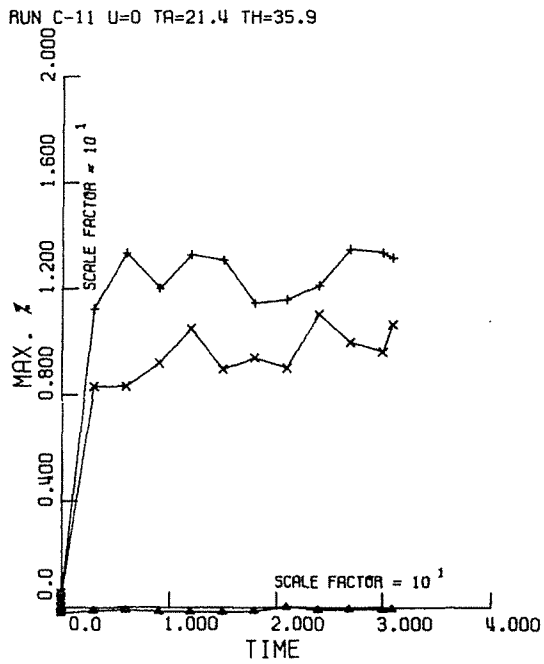

Fig. 5.4. Summary of maximum temperature excesses (in percent of source temperature excess) measured anywhere in basin (+), beyond 305 m (1000 ft) of diffusers (x), and ambient temperature (Δ) (Run C-11, u = 0.0 knot).

Water temperatures were computed using a depth-averaged thermal model. Inputs to this model were the calculated natural and plant-induced flows, along with meteorological parameters used for surface heat transfer calculations. The required meteorological variables are incoming solar radiation, cloud cover, air temperature, wind speed, and relative humidity. The incoming solar radiation is the mid-day value, which the code automatically adjusts for the time of day, from sunrise to sunset. The remaining parameters are taken to vary sinusoidally over one day and, therefore, require as input the daily average, the amplitude of the daily variation, and the time of maximum value. Typical values for these parameters during mid-July were used and are shown plotted as a function of time in Fig. 5.7.

This thermal model was first run without thermal output or flow from any of the units to produce a five-day simulation of ambient ocean temperatures. Subsequently, the calculation was repeated, with all three units operating at full capacity, to predict the total temperature field. These two results were then subtracted to generate excess temperature plots. Figures 5.8 through 5.15 show ambient flow and excess temperature plots at 6 hr intervals during the fifth day of the simulation at 2:00 am, 8:00 am, 2:00 pm, and 8:00 pm respectively. Isotherms are plotted in increments of 0.28°C (0.5°F) from 0.28°C (0.5°F) to 2.8°C (5.0°F). In general, the hottest spots occur directly above the discharge for each unit, with Unit 1 being consistently hotter than Unit 2 or 3. In addition, during the part of the tidal cycle when the natural flow is downcoast, there is a secondary warm spot approximately 3000 m (10,000 ft) downcoast of the discharges. This apparently is a result of the influence of the shape of the shoreline on the flow which, in turn, causes the plume from Units 2 and 3 to intersect the plume from Unit 1 at this point downcoast.

California thermal standards require that the 2.2°C (4°F) excess temperature isotherm never reach the shoreline or bottom, and that the 2.2°C (4°F) surface isotherm must be within 305 m (1000 ft) of the discharge point during at least one-half of the tidal cycle. Although the thermal model is depth averaged, it is still possible to address the state standards with the model results because the ambient crossflow has a destabilizing effect upon the discharge buoyancy. During portions of the tidal cycle, the ambient crossflow is of sufficient magnitude to dominate the stable stratification, resulting in mixing of the plume to the ocean bottom in the neighborhood of the diffuser. Recent work by Almquist[8] provides the basis for determination of conditions for vertical mixing. According to Almquist, the warm plume will mix to the bottom when the ratio of the ambient crossflow velocity to the cube root of the buoyancy flux per unit length of diffuser is greater than one. Figure 5.16 (a) is a plot of this stability parameter versus time for one tidal cycle based on the staff's ambient flow predictions. The shaded area shows the period during the tidal cycle when instability will occur and the water column will be vertically homogeneous.

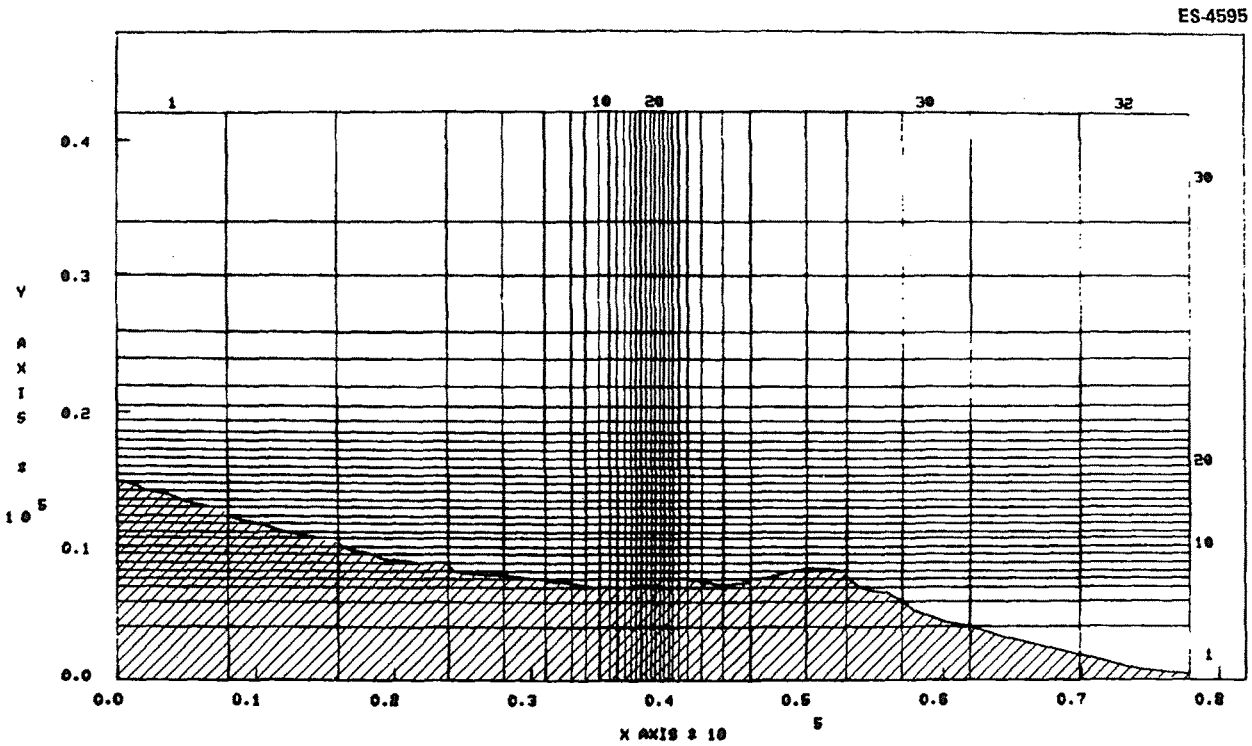

Fig. 5.5. Plot of region and grid system used for the mathematical model applications.

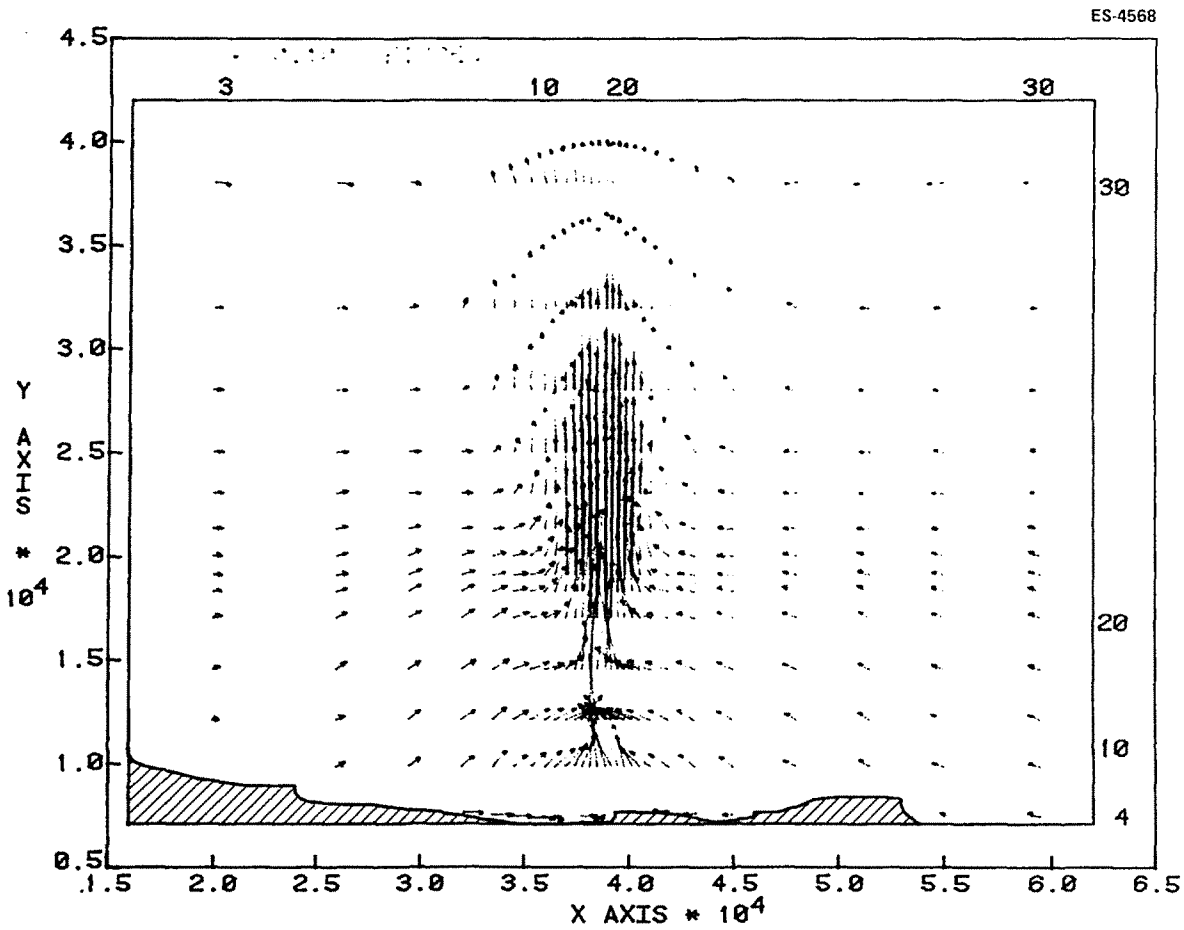

Fig. 5.6. Predicted, depth-averaged, plant-induced flow field for Units 1, 2, and 3.

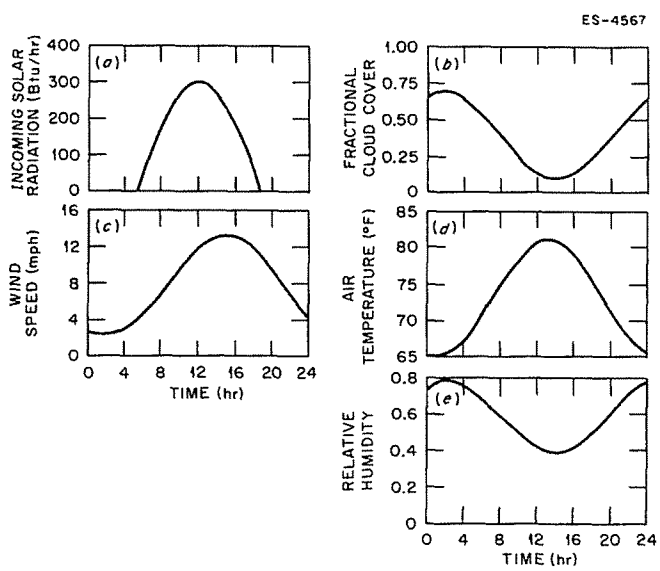

Fig. 5.7. Plots of meteorological variables as a function of time use in the thermal model. (To convert mi to km, multiply by 1.6; to convert °F to °C, subtract 32 and divide by 1.8.)

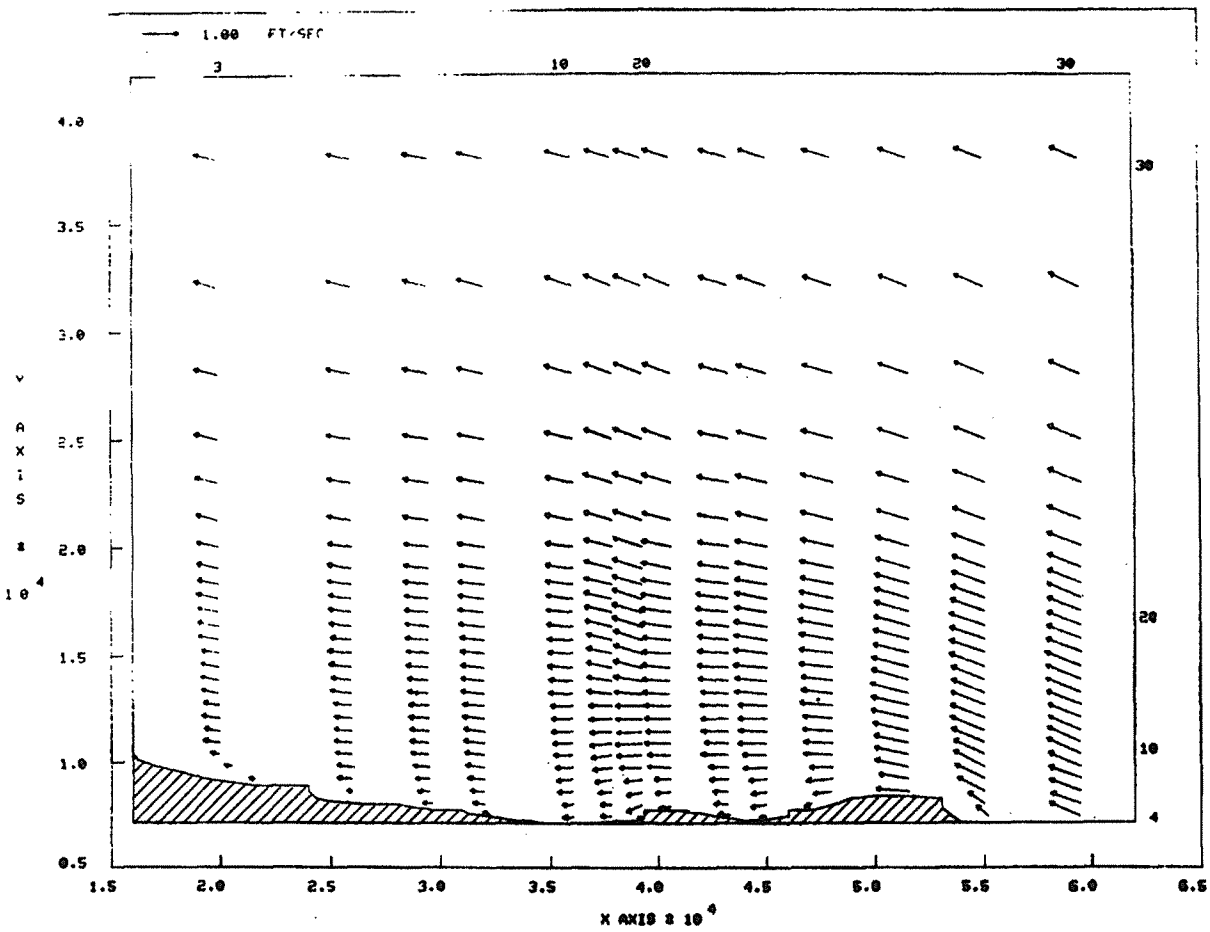

Fig. 5.8 Predicted natural flow field in the San Onofre region at 2:00 a.m. on the fifth day. (To change ft to m, multiply 0.3048; to change °F to °C, subtract 32 and divide by 1.8.)

Figure 5.16 (b) is a plot of the maximum excess temperature in the vicinity of the diffuser as a function of time for one tidal cycle. The shaded portion of this curve represents the period during the tidal cycle when the excess temperature is greater than or equal to 2.2°C (4.0°F) and the plume is vertically well mixed. In other words, the shaded area in this figure reflects the portion of the tidal cycle that will violate state thermal standards as applied to excess bottom temperature. It is clear from this figure that bottom excess temperatures greater than 2.2°C (4.0°F) are predicted to occur for two hours during the tidal cycle. Because, however, this prediction, based on a low ambient drift current, is conservative, excessive incremental bottom temperatures should not occur during each tidal cycle but rather during periods of worst case conditions.

With an assumed persistent drift, the data shown in Figs. 5.8 through 5.15 indicate that the constraints on the surface and shoreline excess temperature will be satisfied. The model is inadequate for addressing the issue of bottom temperature. However, at worst, the 2.2°C (4°F) excess temperature should only touch the bottom over a very limited area in the vicinity of the Unit 2 and 3 diffusers. On the basis of these results, the staff believes that violations of the state thermal standards are unlikely.

Heat treatment

Heat treatment will be necessary to control biological growth in the discharge conduits, intake conduits, and screenwells. Heat treatment consists of decreasing the flow rate through the heat-dissipation system while maintaining a constant waste-heat rejection rate. The result is an increased temperature rise across the condensers.

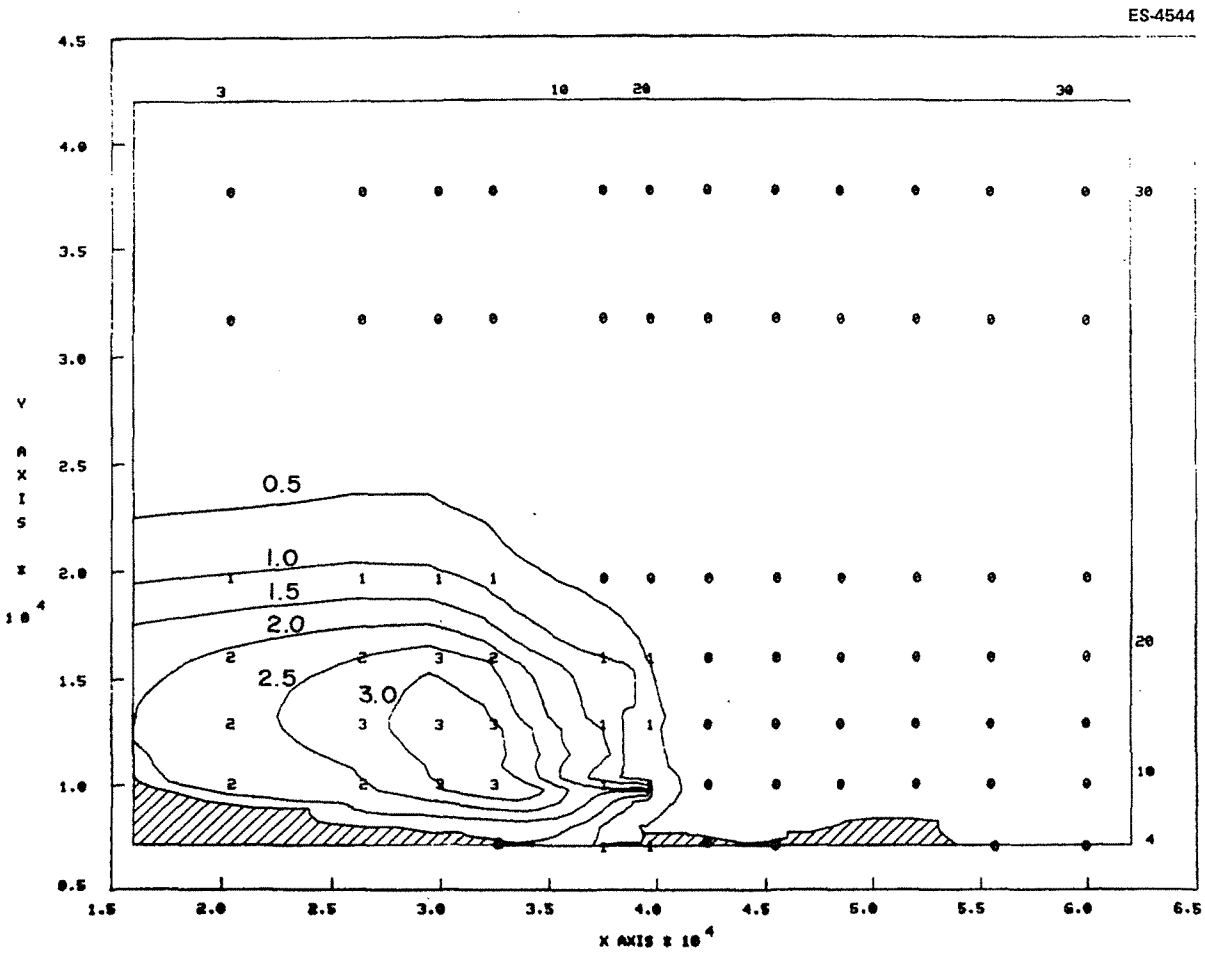

Fig. 5.9. Predicted excess temperatures in the San Onofre region at 2:00 a.m. on the fifth day. Isotherms are plotted in increments of 0.28°C (0.5°F) beginning with the 0.2°C (0.5°F) isotherm. (To change F° to C°, divide by 1.8.)

Discharge heat treatment will be required only when none of the following conditions are met:

1. discharge temperatures exceed 26.7°C (80°F) for a minimum of 1000 hrs,

2. discharge temperatures exceed 29.4°C (85°F) for 150 hrs, or

3. discharge temperatures exceed 32.2°C (90°F) for 31 hrs.

On the basis of these conditions it is expected that discharge heat treatment will be required only infrequently and usually during the winter. When discharge heat treatment is required, it will be performed at a discharge temperature of 40.6°C (105°F) for a duration of 1.1 hrs for Unit 2 and 0.9 hrs for Unit 3. During discharge heat treatment, discharge flow rates will be reduced and discharge temperatures will be increased. The discharge excess temperature will be the difference between the ambient water temperature and 40.6°C (105°F.) The reduction in the discharge flow rate will be proportional to the increase in the discharge excess temperature.

Although the exact nature of the thermal plume resulting from discharge heat treatment will be dependent upon the ambient conditions at the time of heat treatment, the thermal plume will be qualitatively similar to the plume resulting from normal operation as shown in Figs. 5.9, 5.11, 5.13, and 5.15. However, the flow is reduced and the temperature increased, so that the plume will be somewhat warmer and smaller in spatial extent than that from normal operation. The greatest plume temperatures will occur if Units 2 and 3 are heat treated simultaneously. A warmer plume will persist the longest when the heat treatment for these units are sequenced.

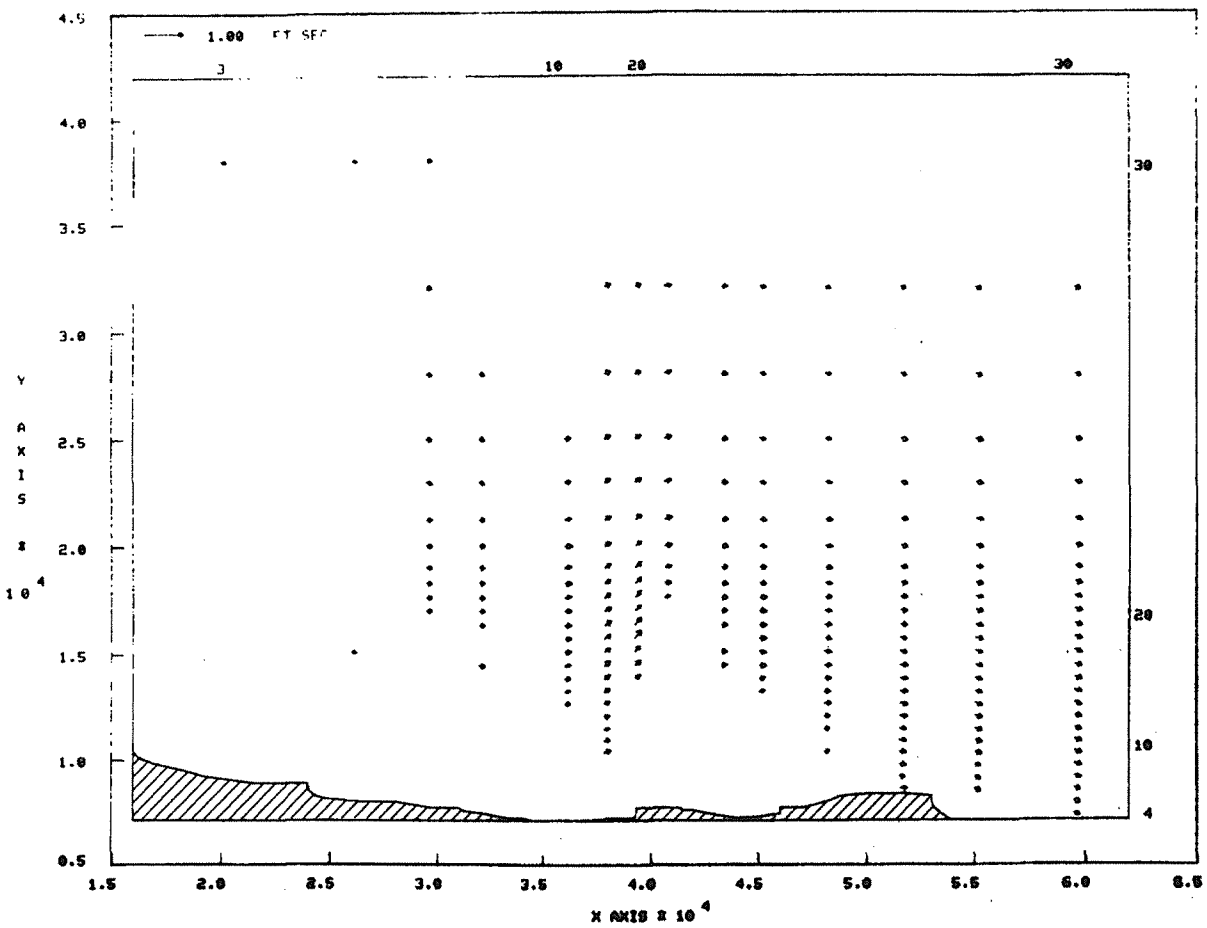

Fig. 5.10. Predicted natural flow field in the San Onofre region at 8:00 a.m. on the fifth day. (To change ft to m, multiply by 0.3048; to change F° to C°, divide by 1.8.)

During the summer months, discharge heat treatment should increase far-field plume temperatures by no more than 25% if both units are heat treated simultaneously (an unlikely event due to the increased probability of a reactor scram) and by no more than 15% if the units are heat treated sequentially. Plume temperatures at this extreme would persist for several hours, and plume temperatures would return to normal within several tidal cycles.

During the winter, the thermal plume should exhibit temperature distributions no greater that those predicted during the summer (Figs. 5.9, 5.11, 5.13, and 5.15). Excess temperatures during winter heat treatment will be greater than during the summer since a greater condenser temperature rise will be required to meet the design discharge temperature of 40.6°C (105°F). For an ambient water temperature of 10°C (50°F) (typical of winter) excess temperature at the San Onofre kelp bed would be approximately 4°C (7.2°F) if the Units 2 and 3 discharges are heat treated simultaneously and 2 to 3°C (3.6 to 4.8°F) if the discharges are heat treated sequentially.

Intake conduit and screenwell heat treatment will be performed by reducing the flow rate through the heat-dissipation system, thereby increasing the temperature rise across the condensers, and by reversing the flow direction so that ambient water is withdrawn through the diffuser and heated water is discharged from the velocity cap intake. The duration of this heat treatment will be 2.1 hr at an anticipated maximum temperature of 37.8°C (100°F). The plume produced by discharge through the velocity caps will resemble the thermal plume from Unit 1. Since this discharge does not induce the dilution produced by diffusers, the heat-treatment plume will be considerably hotter, though much smaller, than the plume resulting from normal plant operation. Plume temperatures will decrease approximately as the square of the distance from the intakes. Heat treatment on either the Unit 2 or the Unit 3 intake will have an indirect impact on the thermal plume of the unit operating normally. If, for example, the Unit 2 intake is heat treated while Unit 3 is operating normally, the Unit 2 heat treatment plume could be advected during certain times in the

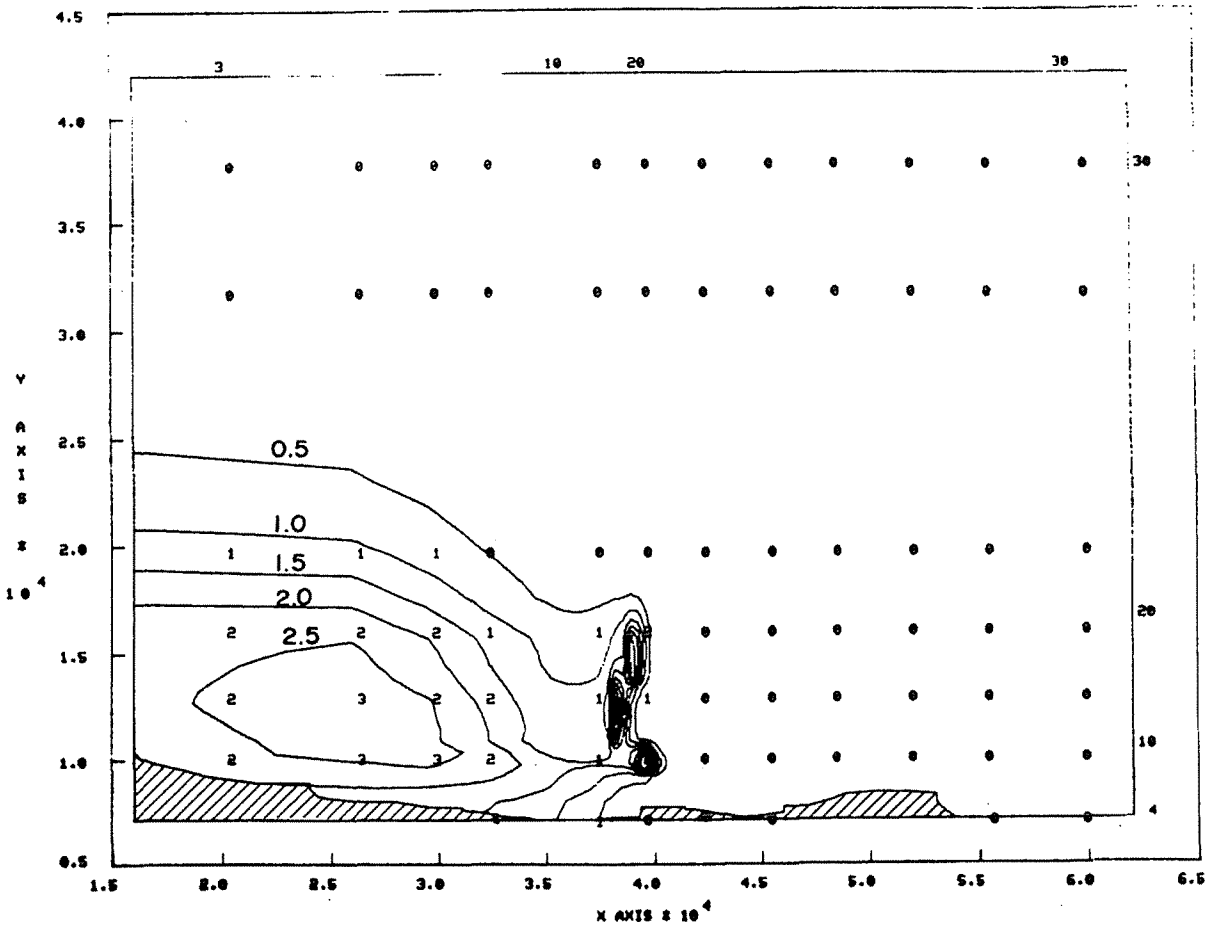

Fig. 5.11. Predicted excess temperatures in the San Onofre region at 8:00 a.m. on the fifth day. Iostherms are plotted in increments of 0.5°F beginning with the 0.5°F isotherm. (To change F° to C°, divide by 1.8.)

tidal cycle towards the Unit 3 intake. As a result, water at temperaures above the ambient could be drawn into the Unit 3 intake, resulting in a temperature rise in the Unit 3 discharge plume. Similarly, Unit 3 intake heat treatment could affect the plume from Unit 2. This recirculation phenomenon will be offset by virtue of the fact that only one unit will be discharging through the diffuser. Therefore, far-field diffuser plume temperatures will likely be less during intake heat treatment than during normal plant operations.

Both discharge and intake heat treatment will produce plumes showing temperatures greater than plume temperatures expected during normal operations. These increased temperatures will be greatest near the point of discharge, and will be of short duration returning to normal within several tidal cycles after completion of heat treatment.

Should it be determined that heat treatment results in significant excess temperatures at biologically sensitive areas, impacts could be mitigated by scheduling heat treatments during phases of the tidal cycle (such as periods when the tidal flow will transport the thermal plume away from areas of concern) that will minimize excess temperatures occurring in such areas.

5.3.2 Chemical discharges

The assessment of the effect of chemical discharges on water use contained in the FES-CP (5.2) is still, for the most part, valid. The discussion of the impacts of copper and nickel discharges has been altered by the change to titanium condenser tubes (3.2.4.1), and these discharges should not affect water use since the tubes no longer contain copper or nickel.

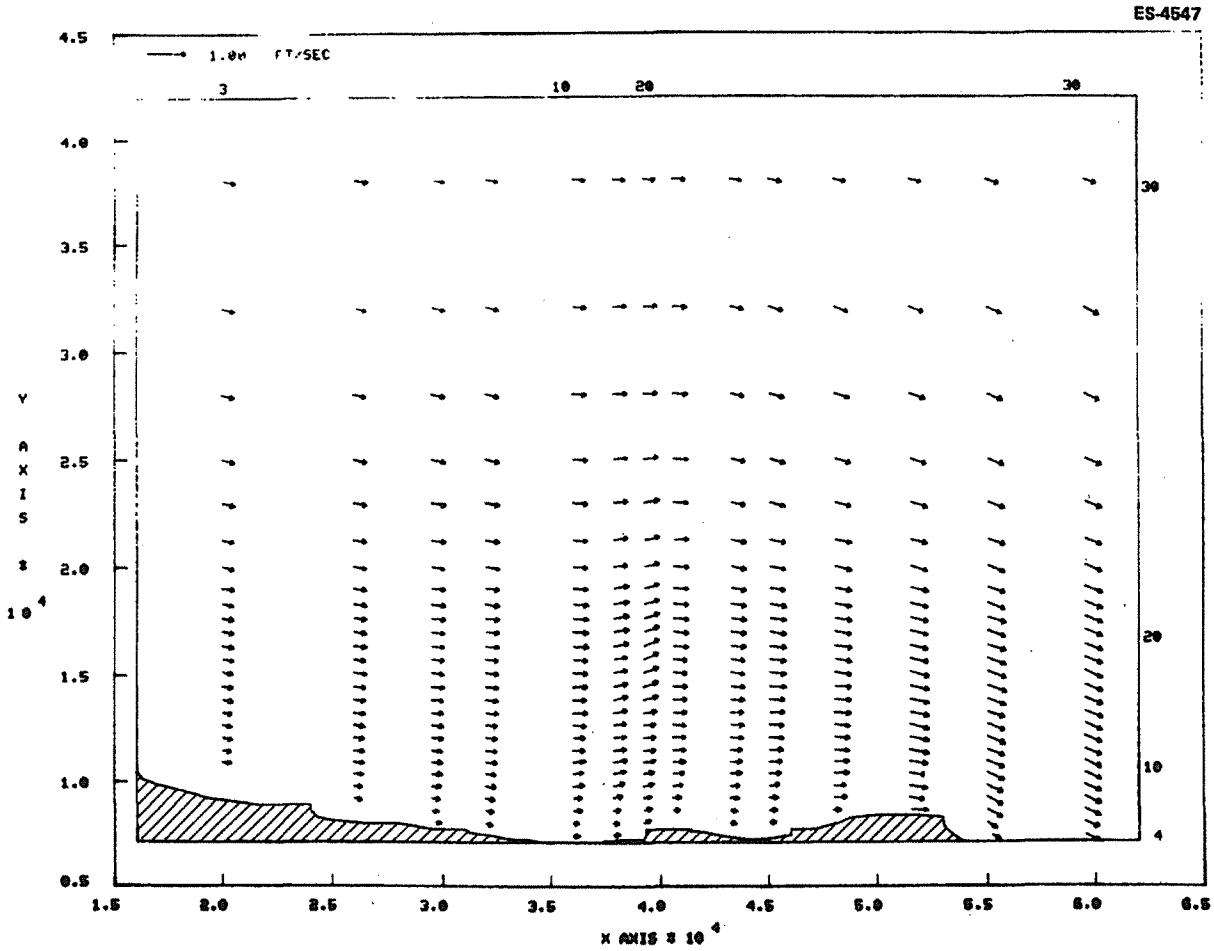

Fig. 5.12. Predicted natural flow field in the San Onofre region at 2:00 p.m. on the fifth day.

A National Pollutant Discharge Elimination System Permit for SONGS 2 & 3 was issued on June 4, 1976, by the California Regional Water Quality Control Board, San Diego Region. The chemical effluent limitations imposed by this permit are given in Sect. 3.2.4.1.

5.4 ENVIRONMENTAL IMPACTS

5.4.1 Terrestrial environment

Generally, operation of SONGS 2 and 3 and associated transmission lines should have no significant impact on the terrestrial ecological characteristics of the area. Although the transmission line routes have been modified since the issuance of the construction permit (3.2.5), the analysis of projected impacts as set forth in the FES-CP (5.3.1) remains the same. All new transmission lines will be constructed on existing rights-of-way; a total of 5.2 ha (12.8 acres) of land will be required for access road extensions and for new tower bases. The fire break which was bulldozed adjacent to the transmission line on Camp Pendleton Marine Base is expected to be maintained by periodic blading. Impacts associated with this operation should be minimal.

Other potential terrestrial impacts associated with operation of SONGS 2 and 3 which were not addressed in FES-CP are as follows. Some audible noise will be generated from the operation of the transmission lines. Noise levels, however, will be well within the urban evening levels accepted by the public (ER, Section 5.5.1). The transmission lines will be designed to minimize any affects on radio and television reception (ER, Section 5.5.1). Maintenance of the transmission lines (washing and repair work) requires that the access

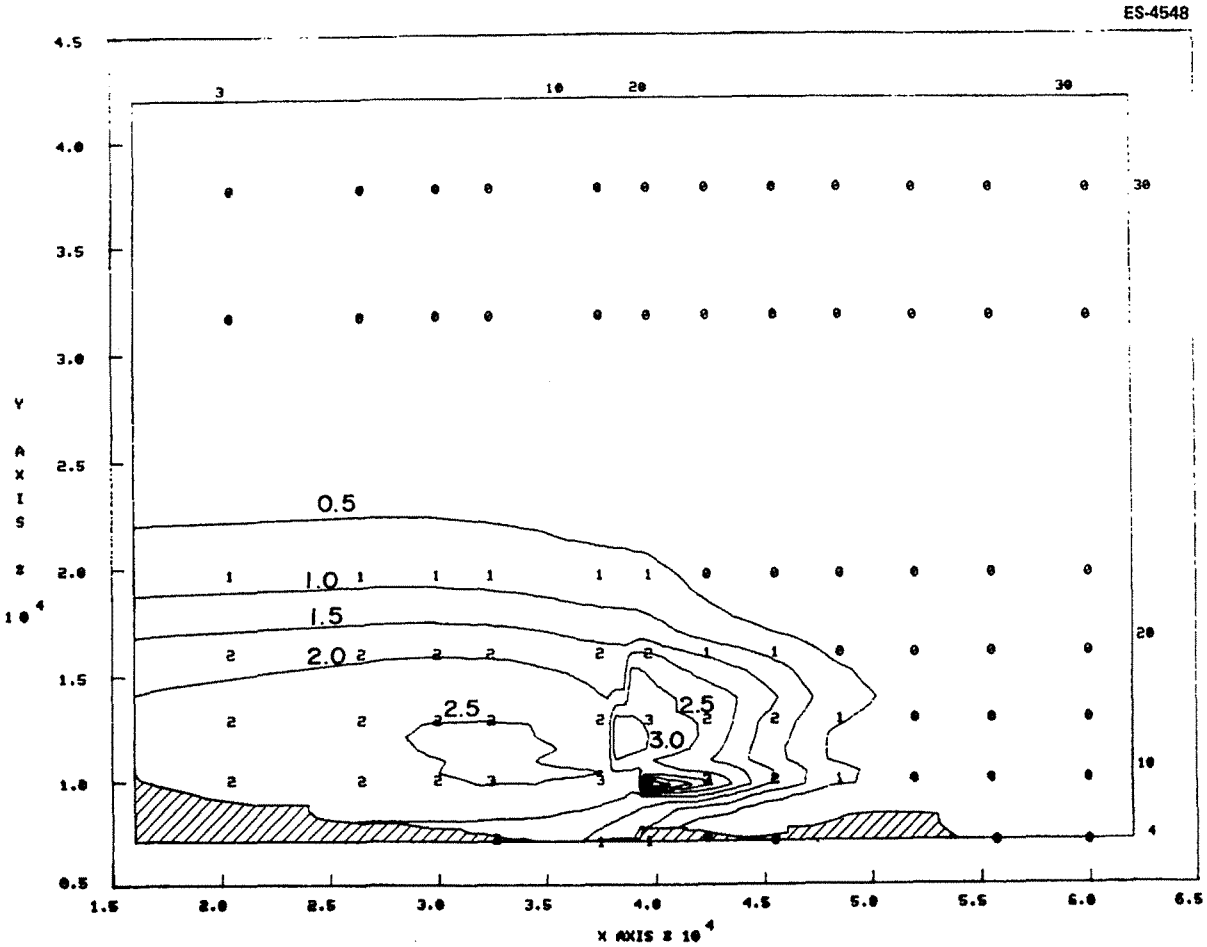

Fig. 5.13 Predicted excess temperatures in the San Onofre region at 2:00 p.m. on the fifth day. Isotherms are plotted in increments of 0.5°F beginning with the 0.5°F isotherm. (To change F° to C°, divide by 1.8.)

roads be kept in good condition by blading (ER, Suppl. 1, Item 21); associated impacts should be minimal. Maximum ground-level field gradients for all transmission lines will not exceed 7.5 kV/m (ER, Suppl. 1, Item 20). Generally, no harmful effects occur from the electrical fields associated with lines operating at 230 kV and below.[9]

5.4.2 Impacts on the aquatic environment

5.4.2.1 Effects of the heat dissipation system

A description of the heat dissipation system to be employed at SONGS 2 and 3 is found in Sect. 3.3 of the FES-CP. Design changes that have occurred since then are discussed in 3.2.2 of this statement. The only changes of potential significance for the assessment of biological effects involve the final specifications for the fish return system, the biocide use program, and the composition of the condenser tubing. Assessments of most major potential impacts also have been reevaluated in light of additional data obtained during technical specifications monitoring programs for SONGS 1 and from construction and preoperation monitoring programs for SONGS 2 and 3 (Section 2.5.2). Except as noted, the reassessments have resulted in the same conclusions that were reached in the FES-CP.

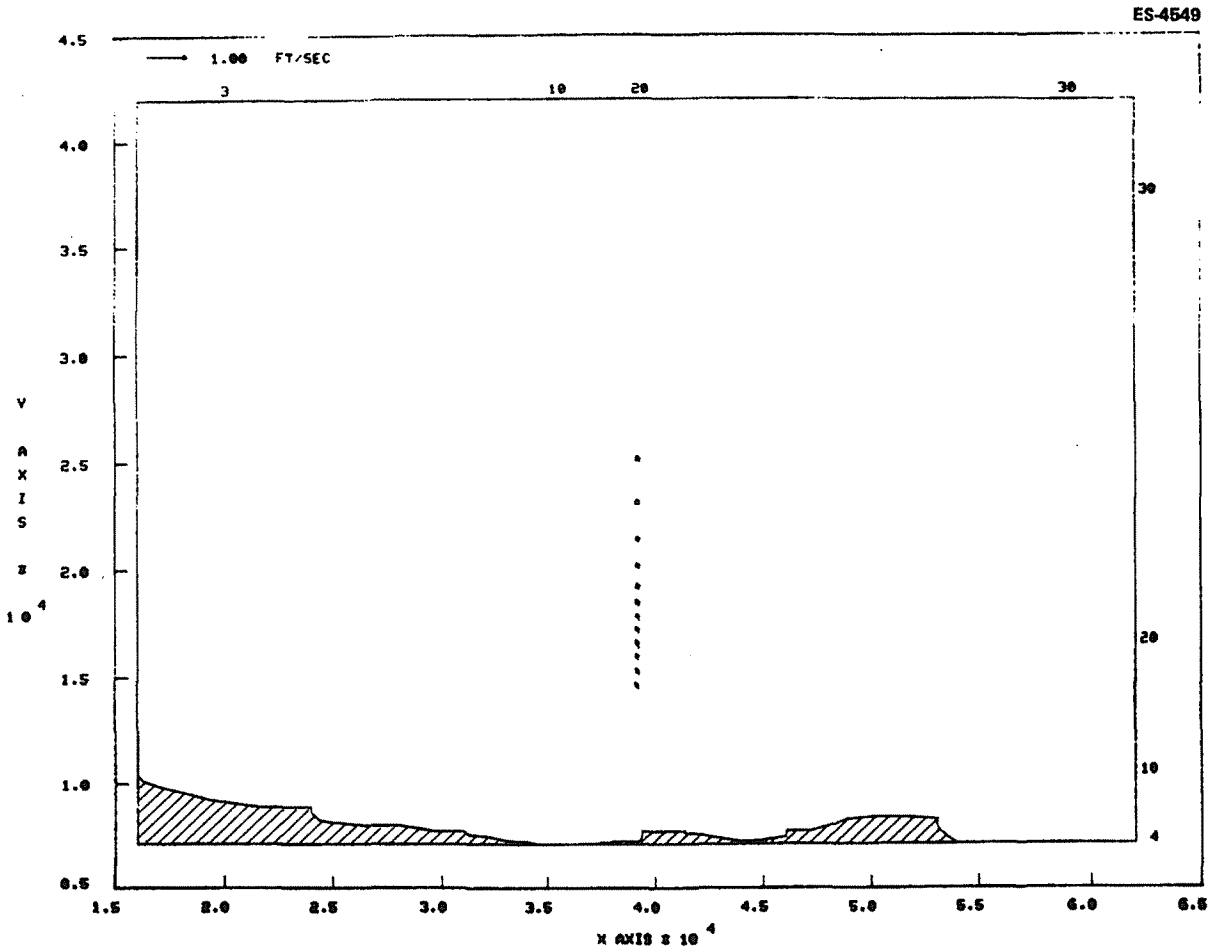

Fig. 5.14. Predicted natural flow field in the San Onofre region at 8:00 pm on the fifth day.

Thermal effects

The discharges from SONGS 2 & 3 must conform to regulations of the California State Water Resources Control Board, the Environmental Protection Agency (with regard to thermal discharges), and the California Regional Water Quality Board, San Diego Region, (under the auspices of the EPA) with regard to NPDES permit considerations (primarily chemical effluent limitations). The regulatory restrictions on thermal discharges are found in Sect. 5.1.1 of the ER; the NPDES permit, as amended, is found in Appendix 12C of the ER.

The results of thermal models used to evaluate temperature increases attributable to SONGS 2 & 3 (and incremental to SONGS 1) are discussed in Sect. 5.3.1. These data indicate that the thermal plume characteristics will be different from those estimated in the FES-CP and in the ER. Since the area to be affected by thermal discharges is now estimated to be greater than previously thought and since areas of substantial biological importance potentially will be affected (e.g., kelp beds), a reassessment is necessary.

Plankton. More planktonic organisms will be affected by thermal discharges than estimated in the FES-CP because the plume will cover greater area. The types of impact will, however, be the same (e.g., species compositon changes, greater respiration rates), and significant changes should be localized. The staff believes that changes which are produced in plankton communities will not threaten the ecological integrity of the near-shore region surrounding the facility (see pp. 5-26 to 5-32 of the FES-CP for a description of the anticipated effects).

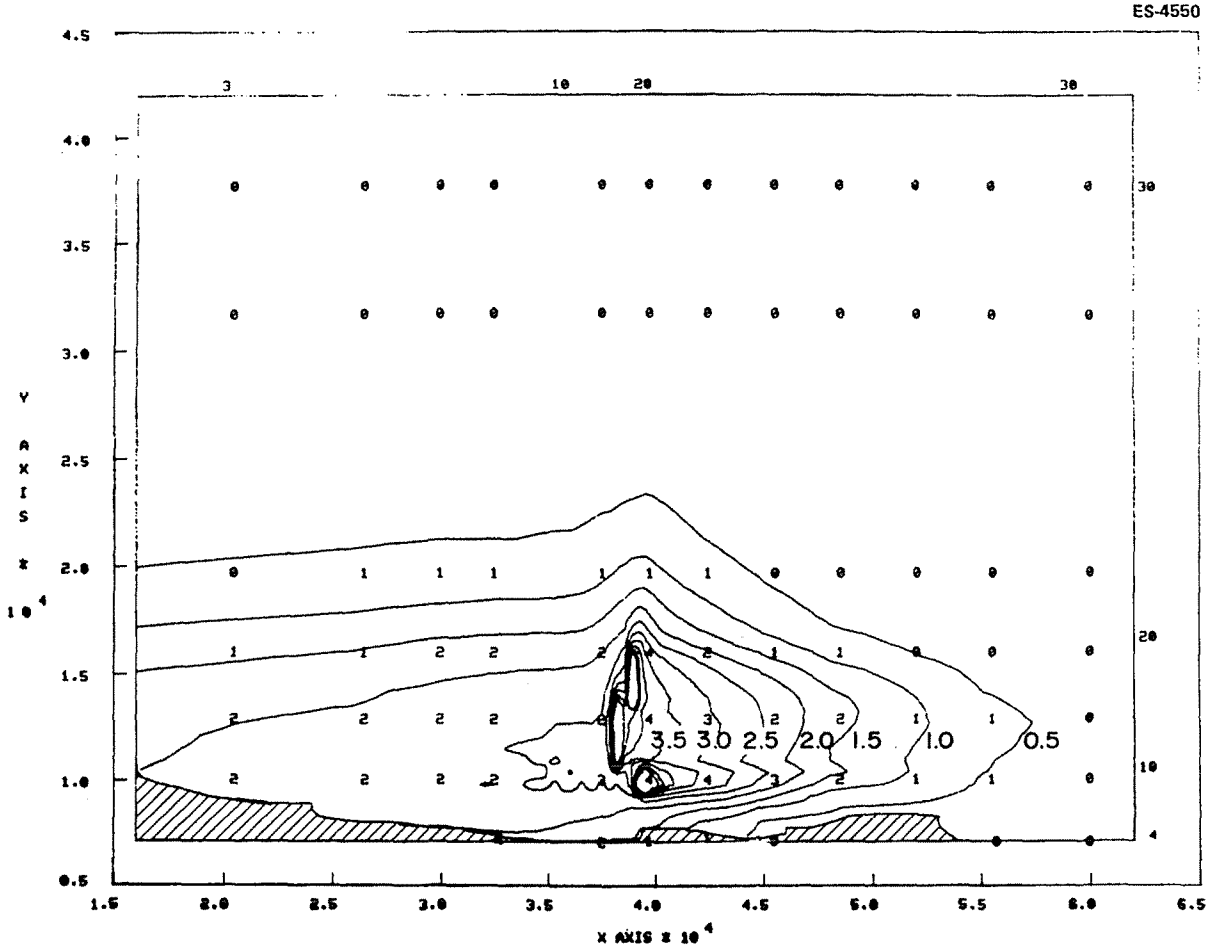

Fig. 5.15. Predicted excess temperatures in the San Onofre region at 8:00 p.m. on the fifth day. Isotherms are plotted in increments of 0.5°F beginning with the 0.5°F isotherm. (To change F° to C°, divide by 1.8)

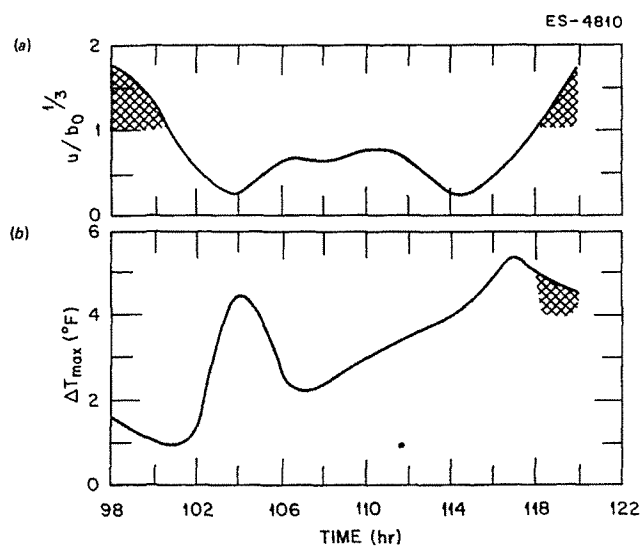

Fig. 5.16. (a) Plot of stability parameter versus time. The shaded area represents periods of vertical mixing. (b) Plot of maximum excess temperature versus time. The shaded area represents the period during which excess bottom temperatures are predicted to be greater than 4°F. (To change F° to C°, divide by 1.8.)

Fish. The types of impact on fish to be expected as the result of thermal discharges are the same as those discussed in the FES-CP. However, with more area to be influenced by the effluent, more fish potentially will be affected. The most observable change is likely to be shifts in the types of species (and their numbers) which inhabit the area; e.g., species which normally exhibit increased standing crops during naturally warm years will be more prevalent. Although the area of potential impact will be greater than estimated before, no fish populations are expected to be adversely impacted in the vicinity of the facility. Species composition changes, however, may affect commercial and recreational fishing within the thermal plume (in some cases adversely, and in others, beneficially; see FES-CP for details). However, because the plume will occupy a relatively small area of the available fishing space nearby, no significant changes in harvest rates for the various species are expected.

As stated in the FES-CP, cold kills of fish are not likely to occur to any large degree. The principal reasons are the relatively high ambient winter temperatures and the fact that all three units are not likely to be inoperative at any given time.

Benthic fauna. The major component of the ecosystem expected to receive the greatest impact from thermal discharges is the benthic community. Unlike free-swimming organisms, benthic individuals cannot easily avoid undesirable temperatures. And unlike planktonic organisms, they do not regenerate quickly to compensate for losses or experience continual, rapid recruitment from surrounding waters. Two major categories of the benthic community exist: animals, such as starfish and molluscs, and attached algae, the most conspicuous of which is kelp (discussed in the following section).

Among the benthic fauna recorded in the vicinity of SONGS during surveys conducted in 1977 in compliance with Environmental Technical Specifications criteria for SONGS Unit 1 were the gastropod molluscs *Astraea undosa*, *Kelletia kelletii*, and *Roperia poulsoni*, the asteroid echinoderm *Pisaster giganteus*, and the echinoid echinoderm *Strongylocentrotus franciscanus*.[10]

Although there have been only a limited number of detailed studies concerning the effects of temperature on marine species inhabiting the Pacific Coast, some recent laboratory simulation experiments of 12 to 14 weeks duration have examined the effects of thermal effluent on the survival, growth, and state of health of seven motile invertebrates from shallow rocky habitats along the southern California coast.[11] The treatment conditions simulated temperatures measured at distances of 84 and 335 m (276 and 1098 ft) from the cooling-water discharge structure of the Redondo Generating Station, located approximately 100 km (62 miles) upcoast of SONGS. Several of the species displayed low survival and impaired growth, especially among large adults, in response to the simulated thermal plume conditions at 84 m. Weekly mortality data for *S. franciscanus*, *P. ochraceus*, and *R. poulsoni* showed that individuals of all three species began to die when the temperature fluctuated over a range of 19° to 23°C (66° to 73°F), with a mean for the week of 21.4°C (70.5°F). No deaths had occurred the previous week when the same temperature range prevailed and the mean was slightly higher 22.8°C (73°F). The mortality observed during the second of these two weeks may, however, actually have been a delayed response to the higher average temperature of the previous week.

In the test involving *R. poulsoni* under a different thermal regime, deaths began occurring when the temperature flunctuated between 18° and 24°C (64° and 75°F) during the week, with a mean of 20.3°C (68.5°F). Although mortality began to appear at a lower mean temperature than in the previous experiment with this organism, the maximum temperature in this second experiment was 1°C (1.8°F) higher (24° vs 23°C) (75°F vs 73°F) and the temperature range was 2°C (3.6°F) wider (6° vs 4°C) (4.28° vs 39.2°F) than in the previous experiment. These results demonstrate the complicated nature of temperature effects; that is, adverse conditions can result from a critical high temperature of short duration, an extreme temperature fluctuation of short duration, or a prolonged period of a high but normally subcritical temperature.

The ambient depth-averaged temperatures predicted for the hottest time of the year (end of July) in the vicinity of SONGS are shown in 5.3.1. This section also contains data on the temperature expected during the operation of all three units. Temperatures potentially as high as 27.8°C (82°F) may occur naturally, and increases of 0.5° to 1.7°C (0.90° to 3.1°F) brought about by the operation of all three units can occur within an area of several square kilometers.

On the basis of the 1976 study,[11] the staff concludes that several components of the benthic fauna in the vicinity of SONGS would probably be adversely affected in areas where weekly mean temperatures of 22°C (71.6°F) prevail for one month or more or where daily temperatures reach or exceed 24°C (75°F). It is not, however, anticipated that temperatures averaging 22°C will occur for more than 2 to 3 weeks or that the area experiencing temperatures of 24°C or greater as a result of SONGS operation will be considerably larger than the area experiencing these temperatures under natural conditions.

The staff concludes that any impacts to the benthic fauna as a result of thermal discharges will be minimal and of an acceptable nature.

Kelp. Kelp beds off California occupy roughly 194 sq km (75 sq mi) of ocean bottom in water depths of 6-18 m (20-60 ft).[12] Although management efforts have possibly halted further severe decline, kelp bed coverage has decreased markedly since about 1920. Although this deterioration may have been partially a result of overharvesting, much of it is probably caused by the increased alteration of the near-shore environment by human activities. In particular, increased temperatures and increased turbidity have been shown to be inimical to kelp survival.[13]

Even without the influence of human perterbations, individual kelp beds experience long-term variations in stand density, productivity, areal extent, etc. Natural factors implicated in causing these variations include storm damage (causing detachment of plants), sand movement (burying holdfasts and causing detachment or prohibiting regeneration), introduction of turbid water masses, high natural temperatures, influx of grazing urchin masses, and fungal and bacterial diseases.[12] Thus, for example, in 1957-59, unusually warm temperatures off southern California caused an estimated loss of 90% of the regions' beds during this period (ER, pp. 2.2-28 and 2.2-29), as judged by surface examinations. Individual beds also commonly display changes in canopy extent during the year. For example, the three beds near the SONGS site showed marked variation in canopy area during 1975 and 1976 (Fig. 2.10). Typically, canopy tissue deteriorates during the warmest time of the year, leaving the basal portion of the plant (which is in cooler water) for regeneration when temperature and light conditions permit.[13] Reduced surface nutrients and higher bottom nutrient mixtures may also contribute to canopy deterioration and basal tissue regeneration respectively.[14]

Kelp beds represent a very important ecological community in California's near-shore waters. It has been estimated that kelp beds are at least three times more productive than the autotrophic components of other near-shore communities. Conservative estimates place the total standing crop of kelp in southern California at 1.8×10^9 kg (2 million tons) and new annual growth potential is on the order of 2-3 times this amount.[13] Kelp beds harbor numerous types of animals and plants, adding greatly to the diversity of an area. Invertebrates commonly found on the plants themselves include ostracods, copepods, amphipods, decapods, polychaetes, nematods, bryozoans, turbellaria and molluscs. Molluscs and echinoderms are kelp grazers prevalent on and around the plants. It is estimated that the larval, juvenile, and adult stages of 25 main sport fish use kelp beds for refuge and food gathering (eating the associated invertebrates, the kelp itself, or other algae), and the average standing crop of fish is estimated to be 300 kg/ha (300 lbs/acre).[13] Kelp not only enter the food chain via grazers, but they contribute large quantities of organic matter to the detritus-based food chains. For example, since several detritus feeders are intermediate in the grazing food chain of many of California's commercial fishes, kelp indirectly influences the populations of these fishes through the production of detritus.[13]

Kelp is an important commercial commodity as well. Although used extensively in the past for such diverse things as fertilizer, cattle feed, and for the production of potassium, acetone, and iodine, most kelp today is processed for the production of algin, a polysaccharide with numerous industrial uses.[12] It is estimated that roughly 15% of the annual kelp production is harvested yearly at a landed value (1964 dollars) of $2 million (market value is roughly 4 times this figure).[13] The kelp beds in the vicinity of SONGS are not now harvested.

Besides the necessity for a favorable physicochemical environment, kelp requires a solid substrate for attachment. Thus, the local distribution of kelp beds in an unperturbed area is largely substrate-dependent. Near the SONGS site, sandy bottoms are prevalent limiting the areas where beds can develop. Natural environmental fluctuations (e.g., higher-than-average temperatures) can virtually denude an area, but, since the casual phenomena are short-lived, kelp beds generally reestablish themselves quickly. However, anthropogenic disturbances frequently completely eliminate kelp beds in their sphere of influence because they generally are of long duration. Even chronic, low-level perturbations which only slightly decrease kelp production often cause the consumption by grazers to outpace new growth.[13]

The temperature tolerance of kelp is probably a reflection of a combination of factors, including physiological responses, susceptibility to disease, and susceptibility to grazing. It has been rather well established that temperatures above 18-20°C (64-68°F) cause deterioration of kelp, and the degree of degradation is directly related to the duration of the exposure to these temperatures. Increased surface temperatures caused by SONGS operation (all three units) would have the effect of extending the period of canopy absence. During the hottest time of the year, data in Section 5.3.1 suggest that the closest kelp bed (San Onofre bed) will experience an average surface temperature increase (over a 24-hr period) of 1.4°C (2.6°F); the range of temperature increase will be 0.6-2.2°C (1-4°F).

Although daily natural temperature variations of 1°C (2°F) are not uncommon in the area (ER, p. 2.2-28), they would not be continuous in nature and thus might not affect the bed

as severely as the continuous SONGS discharges would, where the thermal plume may impinge on the bed for a longer time. Prediction of the degree to which canopy disappearance would be prolonged is impossible. Regeneration would be quicker in years with naturally cooler ocean temperatures, assuming the regenerative tissues remained unaffected (see below).

The greatest threat of SONGS to the long-term survival of the San Onofre kelp bed is the possibility of injury to the basal tissues from which the canopy is regenerated each year as the waters cool. Estimates for bottom temperatures within the bed at the end of July (Section 5.3.1) indicate that temperatures could reach 23-25°C (74-76°F), with a 24-hr mean of 24°C (75°F). Such temperatures would represent a 1-1.5°C (2-3°F) increase above ambient conditions encountered during the hottest portion of the year (conditions which are likely to persist for up to approximately a one-week period) (Section 5.3.1). Although the ambient temperatures given above would in and of themselves be detrimental to the kelp, exposure to them for up to a week would not likely cause permanent degradation of the entire bed[13] because the mean exposure temperature does not quite exceed a recognized threshold temperature for rapid degradation (24°C) and deeper portions of the bed would be slightly cooler than the average and would have a greater probability of maintaining a viable population. However, adding 1-1.5°C to these ambient temperatures could place the bottom kelp tissues in a critical temperature environment subjecting the tissues of most of the plants to temperatures greater than their short-term tolerance, and prolonging the period of time in which the plants would experience temperatures greater than 20°C (68°F), which would cause them to be more susceptible to grazing pressure, diseases, etc., leading to their eventual demise.[13] Since ambient bottom temperature in the region from August – early September may typically range up to 19°C (66°F) (Section 5.3.1), a several week period could exist in which temperatures exceed 19°C.

The information above suggests that the thermal discharges from SONGS 1, 2 and 3 may result in the destruction of at least a portion of the San Onofre Kelp Bed during the summer months. Under average conditions, the result may not be detectable or it may be manifested in a noticeably earlier decline of the canopy. However, under extreme worst case conditions (e.g., several days with high ambient temperatures and slack currents, and with all three plants operating continuously), destruction of the basal regenerative tissues might result. Although recolonization of the area from outside sources could occur during the cooler months, the community, if destroyed frequently, could never achieve a stable state characteristic of other kelp beds in the area. Furthermore, constant temperature increases coupled with added turbidity would be inimical to interim reestablishment since these factors tend to increase the effects of grazing.[13] The perennial occurrence of worst case conditions seems highly unlikely (Section 5.3.1) and the staff thus concludes that the long-term thermal impacts from normal station operation are not likely to be severe. However, in view of (1) the potential additive of synergistic effects of turbidity and sediment with thermal discharges, (2) the ecological importance of kelp beds and their already diminished stature, and (3) the fact that the San Onofre bed represents about one-third of this resource along approximately 16 km (10 mi) of shoreline in the vicinity of SONGS, the staff recommends monitoring to ensure the bed's protection.

Heat treatment

In addition to the thermal discharge associated with the normal operation of the facility (see above), the applicant proposes to heat treat portions of the intake and discharge systems to remove biological growth (see Section 5.3.1.2). This antifouling procedure will result in periodic discharge temperatures higher than those normally encountered. As a result, the state required the applicant to perform a demonstration to determine if significant impacts will result from the procedure. This demonstration, in part provided for under part 316(a) of the Federal Water Pollution Control Act of 1972, was used to determine if the proposed process is acceptable to these government agencies. To date, approvals have been obtained from the California State Water Resources Control Board (Resolution No. 80-95 adopted December 18, 1980), thus removing any regulatory obstacles from the state for conducting the antifouling process.

As stated in Section 5.3.1.2, biofouling control will be needed primarily in the winter; ambient summer temperatures will normally be sufficiently high to obviate the need for the procedure at that time. Additionally, the state has imposed a five-week minimum treatment interval for each unit. Hence, the biological effects will be a manifestation of short-term intermittent stress. Localized mortality and chronic debilitation are inevitable, particularly for sessile organisms. However, only one community of organisms is judged to be significantly vulnerable ecologically – the San Onofre Kelp Bed.

The thermal effects of normal operation on kelp are discussed above along with more detailed information on thermal tolerances, etc. Since intake heat treatment should produce smaller far-field ΔT's than that produced by normal operation (Section 5.3.1.2), the effects on kelp will be less than or equal to the effects induced normally. Discharge heat treatment is

judged to produce potentially greater far-field thermal effects, however. Without dispersing currents (i.e., during a slack in the tidal cycle), kelp bed temperatures during the summer may increase by ca. 0.4°C (0.72°F) (above normal operations) (Section 5.3.1.2). This negligible increase would not be likely to affect the kelp, particularly since the canopy will be naturally reduced (see kelp discussion above) and the heated water is not likely to be near the bottom.

Discharge heat treatment during the winter may cause a temperature increase in the kelp bed of up to 4°C (7.2°F). The kelp are ordinarily tolerant of the absolute temperatures this would produce, but the rapid heat-up involved (e.g., 0.5 h) could be deleterious since the kelp would not be "hardened" for such a temperature regime. However, it is not possible to tell from the literature the severity of such an event. The plants could be only temporarily taxed physiologically and rebound without sequelae. Conversely, the stress could initiate an increased vulnerability to other, natural stresses such as predation, sloughing, and encrustation. Overt mortality is unlikely. In the absence of definitive data, it would be wise to (1) ensure continuation of the kelp monitoring program and (2) attempt to avoid heat treatment during unfavorable ocean current conditions. As pointed out in Section 5.3.1.2, effects can be mitigated by staggering heat treatment at Units 2 and 3 (thus allowing thermal dispersion from the first treated unit before treating the second) and by conducting the antifouling procedures when current and tidal cycles are known to move the adjacent water mass away from the kelp bed.

Turbidity and sediment transport effects

The FES-CP discusses the types of effects turbidity increases due to SONGS operation will have on the various biological communities, indicating that it is not possible to predict the areal extent of this impact.

The organisms likely to receive the greatest impact from increased turbidity are those which cannot readily avoid adverse conditions or do not regenerate quickly (or experience rapid recruitment from surrounding waters), namely, the benthos. Since the San Onofre Kelp Bed is estimated to be enveloped within the thermal plume, it is likely that it will also experience increased turbidity. The effect on the kelp would potentially be decreased photosynthesis, possibly causing many of the plants to die if the exposure is continuous (a 1% increase in the absorption coefficient has been found to result in a 20% loss in net photysynthesis at 15 m (49.2 ft)[13] and burial of the holdfasts in particles which settle out, inhibiting regeneration and recolonization. Regardless of the magnitude of these effects, their presence would add to the probability that the kelp bed would be adversely affected (see preceding section).

Some of the effects of increased sediment transport on benthic fauna are addressed in the FES-CP. The staff has further addressed the impact of the change in sediment size in areas near the SONGS site which would result from sediment redistribution. A study conducted during SONGS 1 operation, shutdown, and subsequent startup showed a significant reduction in the number of species and the total abundance of individual benthic fauna (primarily molluses and polychaete worms) within 200 m (656 ft) of the intake and discharge structure, probably because of the coarsening of the grain size of the sediments in this area.[15] Sediment coarsening appears to be mainly a result of the discharge of shells and shell fragments of fouling organisms (barnacles, molluscs) sloughed from the insides of the intake and discharge pipes during normal operation and especially during heat treatment.

The sediment-altered area associated with SONGS 1 (following 13 years of operation) is estimated to be approximately 125,600 m^2 (.048 mi^2), on the assumption of a circular pattern of effect with a radius of 200 m (656 ft).[15] Assuming sediment alteration associated with SONGS 2 and 3 forms a rectangular pattern approximately 200 m from the sides and ends of each diffuser, the area affected by SONGS 2 and 3 would be approximately 0.8 km^2 (0.31 mi^2). Adding this to the area affected by SONGS 1 (125,600 m^2 (0.48 mi^2)) plus an estimate of the area affected by heat-treatment backflushing of the SONGS 2 condenser (59,900 m^2 (0.023mi^2)) gives a total area affected by all three units, from both normal operation and heat treatments, of approximately 1.0 km^2 (.386 mi^2).

It is difficult, however, to extrapolate from the effects associated with the point source discharge of SONGS 1 to the 762-m (2500-ft) long dual, staggered diffusers of SONGS 2 and 3. SONGS 2 and 3 jointly are expected to have 5 times the cooling water flow rate, 3.3 times the intake pipe area per intake structure, and 12.5 times the total fouling surface area associated with the two outfall lines that SONGS 1 has.[15] None of these factors has been taken into consideration in calculating the area potentially affected by SONGS 2 and 3. The magnitude of the effect will also increase with duration of operation.

In contrast to the above prediction of benthic impoverishment, the staff concludes that a zone of enhanced species diversity and abundance is to be anticipated beyond the area of

sediment modification. This conclusion is also based on results of the Marine Review Committee study,[15] which indicates that within a zone of 200 to 800 m (656 to 2424 ft) from the intake and outfall of SONGS 1, diversity and abundance of benthic fauna show a positive correlation with proximity to these structures. It has been estimated that this area contains 2 times the diversity and 8 times the abundance of benthic fauna as the sediment-altered area within the 200-m (656-ft) radius of the outfall. This phenomenon is believed to be a result of organic enrichment from sinking plankton fragments and/or material continually resuspended by the localized turbulence of the discharged cooling water.[15]

Assuming an eliptical ring pattern for this area of enhancement, starting from a point 200 m (656 ft) on either side of the intake and outfall structures of SONGS 1, to 1200 m (3936 ft) upshore and downshore (the extent of enhancement appears to diminish between 800-1500 m (2624-4920 ft) downcoast) and extending for a distance of 400 m (1312 ft) beyond the 200-m (656-ft) point in the onshore and offshore directions (offshore/onshore effect is much less than longshore), the area of enhancement is estimated to be approximately 2.1 km^2 (0.81 mi^2).

Predicting the magnitude of an enhancement effect associated with SONGS 2 and 3 on the basis of SONGS 1 observations is complicated. The total volume of dead plankton dispersed might be approximately 5 times that of SONGS 1 as a result of the 5-fold increase in cooling water flow rate. However, the volume of discharge for each diffuser port is less than for the single outfall of SONGS 1 so that the distance the entrained plankton are dispersed would be expected to be less. There may also be considerable differences between the shallow current patterns where the SONGS 1 outfall is located and the current patterns in the deeper waters where the SONGS 2 and 3 diffusers will be located.

If it is assumed that the dispersal distances for dead plankton will extend approximately half the distance from the sediment-altered area surrounding the SONGS 2 and 3 diffusers as was found associated with the SONGS 1 discharge, and accounting for overlap, the area of enhancement would be approximately 2.4 km^2 (0.93 mi^2). Adding to this the area affected similarly by SONGS 1 gives a total of 4.5 km^2 (1.74 mi^2). This is an area approximately 5 times that estimated to show a reduction in benthic diversity and abundance. The staff concludes that the impacts likely to occur to the benthic fauna as a result of sediment transport effects are acceptable.

Entrainment

The staff's analysis of entrainment effects in the FES-CP remains valid (FES-CP, p. 5-7 to 5-12). A program on the mortality experienced by entrained ichthyoplankton is being planned currently at SONGS 1 and is expected to be submitted to the NRC staff in 1981. The results of this program should help to determine the significance of any impacts although the analysis presented in the FES-CP indicates that impacts should not be significant. The completion date for this study will be approximately one year after it is initiated.

The circulation of water from near-shore areas to offshore areas will cause some redistribution of species, particularly zooplankton, since species composition is not exactly the same for both areas (Section 2.5.2). Although this may result in long-term species composition changes, the areas affected should be small (FES-CP, Section 5.3.2) relative to the coastal areas as a whole around San Onofre. Because no other power plants or industrial facilities that could exert a similar influence exist within several miles, this impact is judged acceptable.

Impingement

The basic impingement analysis contained in the FES-CP remains valid. Some additional information is available, however, on the design and efficiency of the fish return system. The system is described in detail in Section 3.4 of the ER and in Section 3.2.2 of this document. Basically, the fish return system consists of a mechanism for shunting any fish entrained in the intake to a side holding area by means of an angled conduit design to avoid impinging them on the trash removal mechanisms in front of the final intake. Preliminary experimental results (ER, p. 5.1-20) indicate that perhaps 90% or more of the fish can be returned to the ocean unharmed. However, precise figures on the effectiveness of this system will not be available until the fish return system is in full-scale operation. The FES-CP analysis assumes a worst-case situation in which the fish return system is not at all effective. Under these conditions, 33 to 91 tonnes (36 to 100 tons) of fish per year would be removed from the San Onofre area. These figures are based on extrapolations from data obtained on SONGS 1 operation; new data do not indicate that these figures should be adjusted significantly. The majority of the fish impinged at SONGS 1 are queenfish, and, for reasons given in the FES-CP, losses from all three units should not have a significant impact on the population. Moreover, of the dominant recreational fish impinged at SONGS 1, losses were less than 0.8% of the amount taken by fishermen. Likewise, the primary

commercial fish of the area – jack mackerel, Pacific bonito, and white seabass – were seldom entrained at SONGS 1.

Offshore current induction

The analysis of the effects of induced circulation as given in the FES-CP (p. 5-16) remains valid, despite the design changes described in Section 3.2.2.

5.4.2.2 Effects of biocides and other chemical discharges

The FES-CP expressed concern about the potential long-term effects of copper being released into surrounding water by corrosion of the condenser tubing. Design changes have eliminated the plan to use a copper-nickel alloy for condenser tubing; titanium tubing will be used. Therefore, copper- or nickel-induced stresses to the receiving water from condenser tubing would not occur.

The FES-CP conclusion that the effects of chlorine will not be significant remains valid. However, new information is available on this subject. The applicant estimates that the effluent chlorine concentrations will be no greater than 1.5 ppm as total residual before discharge to the ocean (ER, p. 5.3-2). With a 10-to-1 mixing in the immediate vicinity of the diffuser ports (ER, p. 5.3-2), this value would be reduced to 0.15 ppm. The FES-CP required, and the applicant agreed, that the total residual concentration of chlorine and other halogens in the immediate vicinity of the discharge from each unit be limited to less than 0.1 ppm for no more than six 15-min periods each day [FES-CP, p. iv, item 7.a(2)]. Experience at SONGS 1 indicates that total residual chlorine concentrations quickly dissipate to undetectable quantities within a hundred or so meters of the outfall and, for any given 15-min dosing period, are only detectable over the outfall for 2 to 18 min (ER, p. 5.3-2). Even assuming a worst-case condition for SONGS 2 and 3 in which chlorine remains at levels around 0.15 ppm (total residual) in the vicinity of the outfall ports for as long as 30 min, any significant impacts are unlikely.[16] Thus, any chlorine effects are likely to be minimal and of an acceptable nature. Moreover, the difference in effect between discharges of 0.1 and 0.15 ppm are negligible. In view of this and in light of the provisions of the Federal Water Pollution Control Act Amendments of 1972, the staff does not believe that a more stringent limitation on chlorine discharges is necessary.

Miscellaneous chemicals will be discharged through the circulating water outfall system and will include laboratory wastes, ion exchange regeneration chemicals, and pH adjusters (Section 3.2.4 of this document and Section 3.5 of the FES-CP). The FES-CP analysis of the impact of these chemicals remains valid; that is, because of the small quantities involved, the great dilution factors present, and the relatively innocuous nature of most of these chemicals, impacts will not be detectable.

5.4.2.3 Effects of sanitary waste discharge

The effects of sanitary waste discharge are not discussed specifically in the FES-CP. However, any effects will be insignificant for the following reasons.

1. On the average, only about 26 m^3/day (7000 gpd) of secondary treated sewage will be discharged.

2. The discharge will be made into the circulatory water system at the rate of 0.02 m^3/min (5 gpm). The cooling water flow is about 1200 m^3/min (320,000 gpm). Thus, a 6400 dilution factor will result.

3. The resulting concentrations of suspended solids, BOD, N, P, coliform bacteria, and chlorine will not result in detectable incremental increases above ambient levels even before discharge into the ocean.

5.5 RADIOLOGICAL IMPACTS

5.5.1 Radiological impact on man

The impact on man associated with the routine release of radioactive effluents from SONGS 2 and 3 has been estimated. The quantities of radioactive material that may be released annually from the plant are estimated based on the description of the radwaste systems given in the applicant's ER and PSAR and using the calculational model and parameters described in NUREG-0017.[17] Using these quantities and site environs information, the dose commitments to individuals are estimated using models and considerations discussed in detail in Regulatory Guide 1.109. Additional assumptions and models described in Appendix B of this environmental statement were used to estimate integrated population doses.

5.5.1.1 Exposure pathways

The environmental pathways that were considered in calculating the radiological impact are shown in Fig. 5.17. Calculations of radiation doses to man at and beyond the site boundary were based on the radioactive material quantities shown in Tables 3.2 and 3.3, on site meteorological and hydrological considerations, and on exposure pathways at SONGS 2 & 3.

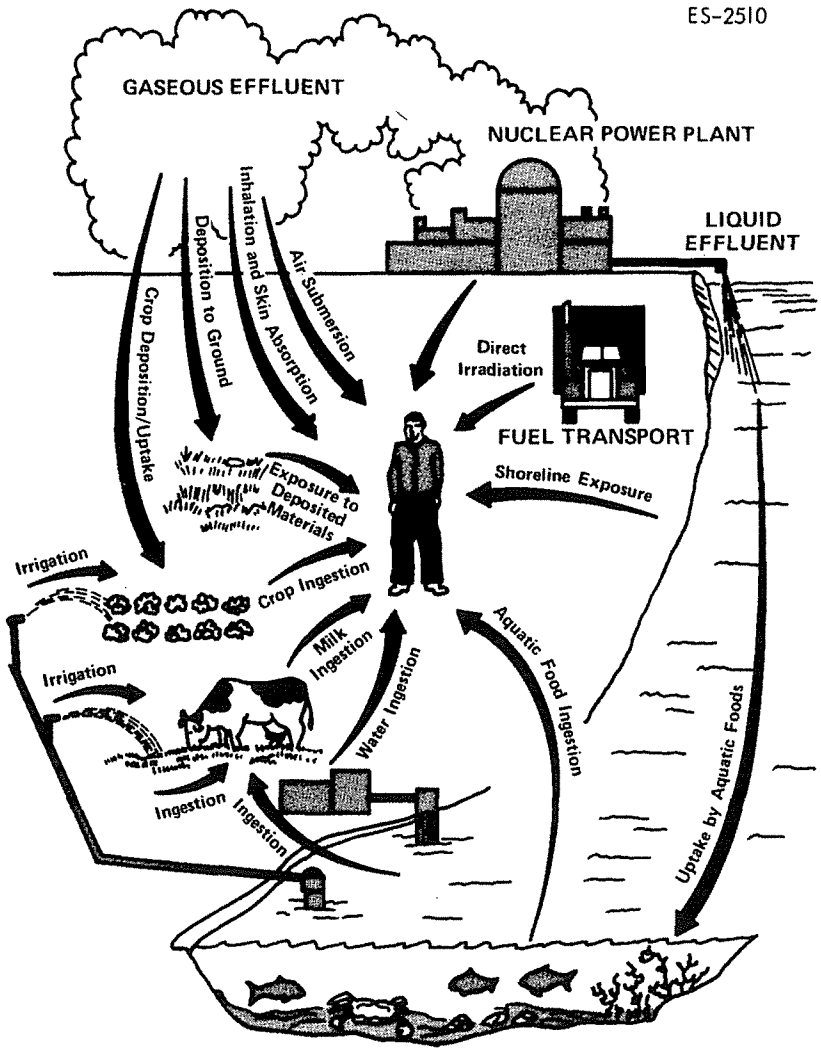

Fig. 5.17. Exposure pathways to man.

In the analysis of all effluent radionuclides released from the plant, tritium, carbon-14, radiocesium and radiocobalt inhaled with air and ingested with food and water were found to account for essentially all total-body dose commitments to individuals and the population within 80 km (50 miles) of the plant.

5.5.1.2 Dose commitments from radioactive releases to the atmosphere

Radioactive effluents released to the atmosphere from SONGS 2 & 3 will result in small radiation doses to the public. NRC staff estimates of the expected gaseous and particulate releases listed in Table 3.3 and the site meteorological considerations discussed in Sect. 2.4 of this statement and summarized in Table 5.1 were used to estimate radiation doses to individuals and populations.

Table 5.1. Summary of atmospheric dispersion factors and deposition values for selected locations near SONGS 2 & 3[a]

Location	Source[b]	X/Q (sec/m^3)	Relative deposition (m^{-2})
Nearest site land boundary (0.36 mile NNW)[c]			
	A	5.4 E–5	2.1 E–7
	B	2.4 E–5	9.3 E–8
Nearest residence and garden (1.3 mile NNW)[c]			
	A	4.8 E–6	2.0 E–8
	B	1.7 E–6	6.9 E–9

[a]The doses presented in the following tables are corrected for radioactive decay and cloud depletion from deposition, where appropriate, in accordance with Regulatory Guide 1.111, Rev. 1, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light Water Reactors," July 1977.

[b]Source A is gas decay tank, 48 purges per year, 12 hr per purge; source B is continuous release.

[c]"Nearest" refers to that type of location where the highest radiation dose is expected to occur from all appropriate pathways.

[d]Here E-x is used to indicate the factor 10^{-x}; i.e., 5.4 E–5 = 5.4 X 10^{-5}

(To change mi to km, multiply by 1.609.)

Dose commitments to individuals and the population can be estimated using different methodologies. The staff's assessment of dose is based on a 50-year commitment and is described in Regulatory Guide 1.109. The results of the calculations are discussed below.

Radiation dose commitments to individuals

The predicted dose commitments to the "maximum" individual from radioiodine and particulate releases are listed in Tables 5.2 and 5.3. The maximum individual has been estimated to receive the highest dose commitment from SONGS 2 & 3 and is assumed to consume well above average quantities of the foods considered (see Table A-2 in Regulatory Guide 1.109). The maximum annual air, total body, and skin doses from noble gas releases are presented in Tables 5.3 and 5.4.

Table 5.2. Maximum annual dose commitments to an individual near the SONGS 2 & 3 plant caused by particulate and liquid effluents

Location	Pathway	Dose (millirems per year per unit)		
		Total body	Thyroid	Other organs (if greater than 10% of dose)
	Iodine and particulate doses			
Nearest residence and garden (1.3 NNW)[a]	Ground deposit	0.66	0.66	NA
	Inhalation	0.07	0.48	
	Vegetation	0.40	2.5	
Totals		1.1	3.7	
	Liquid effluent doses			
Nearest fish	Fish ingestion	0.019	0.018	0.0016
	Invertebrate ingestion	0.0058	0.025	0.104
	Shoreline use	0.039	0.039	0.039
Totals		0.064	0.082	0.15

[a]"Nearest" refers to the location where the highest radiation dose to an individual from all applicable pathways has been estimated.

(To change mi to km, multiply by 1.609.)

Table 5.3. Maximum calculated dose commitments to an individual and the population from SONGS 2 & 3[a]

	Appendix I Design objectives	Calculated doses
	(Annual dose per reactor unit)	
Maximum individual doses		
Liquid effluents		
Dose to total body from all pathways, millirems	3	0.064
Dose to any organ from all pathways, millirems	10	0.15
Noble gas effluents (at site boundary)		
Gamma dose in air, millirads	10	4.6
Beta dose in air, millirads	20	14
Dose to total body of an individual, millirems	5	2.8
Dose to skin of an individual, millirems	15	8.5
Radioiodines and particulates[b]		
Dose to any organ from all pathways, millirems	15	3.7

Population doses within 80 km (50 miles)

	Total body (man-rems)	Thyroid (man-rems)
Natural radiation background[c]	700,000	
Liquid effluents	0.17	0.14
Gaseous effluents	21	46

[a] Appendix I design objectives from Sects. II.A, II.B, II.C, and II.D of Appendix I, 10 CFR 50; considers maximum doses to individuals and population per reactor unit. Source: *Federal Regist.* 40, 19442, May 5, 1975.

[b] Carbon-14 and tritium have been added to this category.

[c] "Natural Radiation Exposure in the United States," U.S. Environmental Protection Agency, ORP-SID-72-1 (June 1972); using the average State of California background dose of 97 millirems per year and year 2000 projected population of 262 million.

Table 5.4. Annual total-body, skin, and air doses at the nearest site boundary of SONGS 2 & 3 caused by gaseous radioactive effluents[a]

Location	Dose (millirem per year per unit)			
	Total body	Skin	Gamma air dose	Beta air dose
Nearest site boundary (0.36 mile WNW)[a]	2.5	8.3	4.2	14

[a] "Nearest" refers to that site boundary location where the highest radiation doses caused by gaseous effluents have been estimated to occur.

(To convert mi to km, multiply by 1.6.)

Radiation dose commitments to populations

The calculated annual radiation dose commitments to the population within 80 km (50 mi) of SONGS 2 and 3 from gaseous and particulate releases are presented in Table 5.3. Estimated dose commitments to the U.S. population are presented in Table 5.5. Background radiation doses are provided for comparison.

Within 80 km of the plant site, specific meteorological, populational, and agricultural data for each of 16 compass sectors around the plant were used to evaluate the doses. Beyond 80 km, meteorological models were extrapolated by assuming uniform dispersion of noble gases and continued deposition of radioiodines and particulates until no suspended radionuclides remained. Doses were evaluated using average population densities and food production values discussed in Appendix B. The doses from atmospheric releases during normal operation represent an extremely small increase in the normal population dose from background radiation sources.

Table 5.5. Annual total-body population dose commitments in the year 2000

Category	U.S. population dose commitment for the site
Natural background radiation, man-rems per year[a]	27,000,000
SONGS 2 & 3 operation, man-rems per year per site	
Plant workers	2600
General public	
Gas and particulates	160
Liquid effluents	<1
Transportation of fuel and waste	14

[a]Using the average U.S. background dose of 102 man-rems per year and year 2000 projected U.S. population from "Population Estimates and Projections," Series II, U.S. Department of Commerce, Bureau of the Census, Series P-25, No. 541 (February 1975).

5.5.1.3 Dose commitments from radioactive liquid releases to the hydrosphere

Radioactive effluents released to the hydrosphere from SONGS 2 & 3 during normal operation will result in small radiation doses to individuals and populations. The staff estimates of the expected liquid releases listed in Table 3.2 and the site hydrological considerations discussed in Sect. 2.3 of this statement and summarized in Table 5.6 were used to estimate radiation dose commitments to individuals and populations. The results of the calculations are discussed below.

Table 5.6. Summary of hydrologic transport and dispersion for liquid releases from SONGS 2 & 3[a]

Location	Transit time (hr)	Dilution factor
Nearest sport fishing location (plant outfall)[b]	0.1	1
Nearest shoreline (plant boundary)	0.1	1

[a]See Regulatory Guide 1.112, "Analytical Models for Estimating Radioisotope Concentrations in Different Water Bodies," (1976).
[b]Assumed for purposes of an upper-limit estimate; detailed information not available.

Radiation dose commitments to individuals

The estimated dose commitments to individuals at selected offsite locations where exposures are expected to be largest are listed in Tables 5.2 and 5.3. The standard NRC models given in Regulatory Guide 1.109 were used for these analyses.

Radiation dose commitments to populations

The estimated population radiation dose commitments to 80 km for SONGS 2 & 3 from liquid releases, based on the use of water and biota from the Pacific Ocean, are shown in Table 5.3. Dose commitments beyond 80 km were based on the assumptions discussed in Appendix B.

Background radiation doses are provided for comparison. The dose commitments from liquid releases from SONGS 2 & 3 represent small increases in the population dose from background radiation sources.

5.5.1.4 Direct radiation

Radiation from the facility

Radiation fields are produced in nuclear plant environs as a result of radioactivity contained within the reactor and its associated components. Doses from sources within the plant are

primarily due to nitrogen-16, a radionuclide produced in the reactor core. Since the primary coolant of pressurized water reactors is contained in a heavily shielded area of the plant, dose rates in the vicinity of PWRs are generally undetectable (less than 5 millirems per year). Low-level radioactivity storage containers outside the plant are estimated to contribute less than 0.01 millirem per year at the site boundary.

Occupational radiation exposure

The dose to nuclear plant workers varies from reactor to reactor and can be projected for environmental impact purposes by using the experience to date with modern pressurized water reactors (PWRs). Most of the dose to nuclear plant workers is due to external exposure to radiation from radioactive materials outside of the body rather than from internal exposure from inhaled or ingested radioactive materials. Recently licensed 1000 MWe PWRs are designed and operated in a manner consistent with the new (post-1975) regulatory requirements and guidelines. These new requirements and guidelines place increased emphasis on maintaining occupational exposure at nuclear power plants as low as is reasonably achievable (ALARA), and are outlined in 10 CFR Part 20, Standard Review Plan Chapter 12, and Regulatory Guide 8.8. The applicant's proposed implementation of these requirements and guidelines are reviewed by the NRC staff at the construction permit licensing stage, the operating license licensing stage, and during actual operation. Approval of the proposed implementation of these requirements and guidelines is granted only after the review indicates that an ALARA program can actually be implemented. As a result of our review the staff has determined that the applicant is committed to design features and operating practices that will assure that individual occupational radiation doses can be maintained within the limits of 10 CFR Part 20 and that individual and population doses will be as low as is reasonably achievable.

On the basis of actual operating experience, it has been observed that this occupational dose has varied considerably from plant to plant, and from year to year. Average individual and collective dose information is available from over 190 reactor-years of operation between 1974 and 1979. These data indicate that the average reactor annual dose at PWRs has been about 410 man-rem, with particular plants experiencing an average annual dose as high as 1300 man-rem. These dose averages are based on widely varying yearly doses at PWRs. For example, annual collective doses for PWRs have ranged from 18 to 5262 man-rem per reactor. The average annual dose per nuclear plant worker has been about 0.8 rem.

The wide range of annual doses (18 to 5262 man-rems) experienced by U.S. PWRs is dependent on a number of factors, such as the amount of required routine and special maintenance, and the degree of reactor operations and inplant surveillance. Since these factors can vary in an unpredictable manner, it is impossible to determine in advance a specific year-to-year or average annual occupational radiation dose for a particular plant over its operating lifetime. It is necessary to recognize that high doses may occur, even at plants with radiation protection programs that have been developed to assure that occupational radiation doses will be kept at levels that are ALARA. Consequently, the NRC staff's occupational dose estimates for environmental impact purposes for SONGS 2 and 3 are based on the conservation assumption that the station may have an higher than average level of special maintenance work. On the basis of the staff's review of the applicant's Safety Analysis Report, as well as occupational dose data from over 190 PWR reactor operating years, the NRC staff projects that the occupational doses at SONGS 2 and 3 could average as much as 1300 man-rem/yr when averaged over the life of the plant. However, actual year to year doses may differ greatly from this average, depending on actual plant operating conditions.

Transportation of radioactive material

The transportation of cold fuel to a reactor, of irradiated fuel from the reactor to a fuel reprocessing plant, and of solid radioactive wastes from the reactor to burial grounds is within the scope of the NRC report entitled "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants" [10 CFR 51.20(g)]. The estimated population dose commitments associated with transportation of fuels and wastes are listed in Tables 5.5 and 5.7.

5.5.1.5 Comparison of dose assessment models

The applicant's site and environmental data provided in the ER and in subsequent answers to staff questions were used extensively in the dose calculations. Any additional data received which could significantly affect the conclusions reached in this draft statement will be used in preparing the final statement.

Table 5.7. Environmental impact of transportation of fuel and waste to and from one light-water-cooled nuclear power reactor[a,b]

Exposed population	Estimated *number of* persons	Range of doses to exposed *individuals* (millirems per reactor year)[c]	Cumulative dose to exposed population (man-rems per reactor year)[d]
Transportation workers	200	0.01 to 300	4
General public			
Onlookers	1,100	0.003 to 1.3	
Along Route	600,000	0.001 to 0.06	3
Accidents in transport			
Radiological effects		Small[e]	
Common (nonradiological) causes		1 fatal injury in 100 reactor years; 1 nonfatal injury in 10 reactor years; $475 property damage per reactor year	

[a]*Data supporting this table are given in the Commission's Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants,* WASH-1238, December 1972, and Suppl. I, NUREG-75/038, April 1975.

[b]Normal conditions of transport: heat (per irradiated fuel cask in transit), 250,000 Btu/hr; weight (governed by Federal or State restrictions), 73,000 lb per truck; 100 tons per cask per rail car; traffic density, <1 per day; rail <3 per month.

[c]The Federal Radiation Council has recommended that radiation doses from all sources of radiation other than natural background and medical exposures should be limited to 5000 milirems per year for individuals as a result of occupational exposure and should be limited to 500 millirems per year for individuals in the general population. The dose to individuals as a result of average natural background radiation is about 102 millirems per year.

[d]Man-rem is an expression for the summation of whole body doses to individuals in a group. Thus, if each member of a population group of 1000 people were to receive a dose of 0.001 rem (1 millirem), or if 2 people were to receive a dose of 0.5 rem (500 millirems) each, the total man-rem in each case would be 1 man-rem.

[e]Although the environmental risk of radiological effects stemming from transportation accidents is currently incapable of being numerically quantified, the risk remains small regardless of whether it is being applied to a single reactor or a multireactor site.

(To convert lb to kg, multiply by 0.45; to convert tons to tonnes, multiply by 0.907.)

5.5.1.6 Evaluation of radiological impact

The actual radiological impact associated with the operation of SONGS 2 & 3 will depend, in part, on the manner in which the radioactive waste treatment system is operated. The staff concludes on the basis of their evaluation of the potential performance of the radwaste system that the system as proposed is capable of meeting the dose design objectives of 10 CFR Part 50, Appendix I. Table 5.3 compares the calculated maximum individual doses to the dose design objectives. However, because the facility's operation will be governed by operating license technical specifications and because the technical specifications will be based on the dose design objectives of 10 CFR Part 50, Appendix I, as shown in the first column of Table 5.3, the actual radiological impact of plant operation may result in doses close to the dose design objectives. Even if this situation exists, however, the individual doses will still be very small when compared to natural background doses (~100 millirems per year) or of the dose limits specified in 10 CFR Part 20. As a result the staff concludes that there will be no measurable radiological impact on man from routine operation of SONGS 2 & 3.

5.5.2 Radiological impacts to biota other than man

Depending on the pathway and the radiation source, terrestrial and aquatic biota will receive doses approximately the same or somewhat higher than man receives. Although guidelines have not been established for acceptable limits for radiation exposure to species other than man, it is generally agreed that the limits established for humans are also conservative for other species. Experience has shown that it is the maintenance of population stability that is crucial to the survival of a species, and species in most ecosystems suffer rather high mortality rates from natural causes. Although the existence of extremely sensitive biota is possible and increased radiosensitivity in organisms may result from environmental interactions with other stresses (e.g., heat, biocides, etc.), no biota have yet been discovered that show a sensitivity (in terms

of increased morbidity or mortality) to radiation exposures as low as those expected in the area surrounding SONGS 2 & 3. Furthermore, in all the plants for which an analysis of radiation exposure to biota other than man has been made, there have been no cases of exposures that can be considered significant in terms of harm to the species, or that approach the exposure limits to members of the public permitted by 10 CFR Part 20.[19] Since the BEIR Report[20] concluded that the evidence to date indicates that no other living organisms are very much more radiosensitive than man, no measurable radiological impact on populations of biota is expected as a result of the routine operation of this plant.

5.5.3 Environmental effects of the uranium fuel cycle

On March 14, 1977, the Commission presented in the *Federal Register* (42 FR 13803) an interim rule regarding the environmental considerations of the uranium fuel cycle. It was effective (by Amendment of September 12, 1978) through March 14, 1979 and revised Table S-3 of Paragraph (e) of 10 CFR Part 51.20.* In a subsequent announcement on April 14, 1978, (43 FR 15613), the Commission further amended Table S-3 to delete the numerical entry for the estimate of radon releases and to clarify that the table does not cover health effects. On July 27, 1979, the Commission approved a final rule setting out revised environmental impact values for the uranium fuel cycle to be included in environmental reports and environmental statements for reactors (44 FR 45362). The final rule reflects new and updated information relative to reprocessing of spent fuel and radioactive waste management as discussed in NUREG-0116, *Environmental Survey of the Reprocessing and Waste Management Portions of the LWR Fuel Cycle*,[21] and NUREG-0216,[22] which presents staff responses to comments on NUREG-0116. The rule also considers other environmental factors of the uranium fuel cycle, including aspects of mining and milling, isotopic enrichment, fuel fabrication, and management of low-and high-level wastes. These are described in the AEC report WASH-1248, *Environmental Survey of the Uranium Fuel Cycle*.[23]

Specific categories of natural resource use are included in Table S-3 of the final rule, which is reproduced in this statement as Table 5.8.† These categories relate to land use, water consumption and thermal effluents, radioactive releases, burial of transuranic and high- and low-level wastes, and radiation doses from transportation and occupational exposures. The contributions in Table 5.8 for reprocessing, waste management, and transportation of wastes are maximized for either of the two fuel cycles (uranium only and no recycle); that is, the cycle that results in the greater impact is used.

The following assessment of the environmental impacts of the fuel cycle as related to the operation of SONGS 2 & 3 is based on the values given in Table 5.8 and the staff's analysis of the radiological impact from radon releases. For the sake of consistency, the analysis of fuel-cycle impacts has been cast in terms of a model 1000 MWe LWR operating at an annual capacity factor of 80%. In the following review and evaluation of the environmental impacts of the fuel cycle, the staff conclusions would not be altered if the analysis were to be based on the net electrical power output of SONGS 2 & 3.

The total annual land requirement for the fuel cycle supporting a model 1000 MWe LWR is about 46 ha (114 acres). Approximately 5 ha (13 acres) per year are permanently committed land, and 40 ha (100 acres) per year are temporarily committed. (A "temporary" land commitment is a commitment for the life of the specific fuel-cycle plant, e.g., mill, enrichment plant, or succeeding plants. On abandonment or decommissioning, such land can be used for any purpose. "Permanent" commitments represent land that may not be released for use after plant shutdown and/or decommissioning.) Of the 40 ha per year of temporarily committed land, 32 ha (79 acres) are undisturbed and 9 ha (22 acres) are disturbed. Considering common classes of land use in the U.S.,‡ fuel-cycle land-use requirements to support the model 1000 MWe LWR do not represent a significant impact.

The principal water-use requirement for the fuel cycle supporting a model 1000 MWe LWR is that required to remove waste heat from the power stations supplying electrical energy to the enrichment step of this cycle. Of the total annual requirement of 43 x 10^6 m^3 (11,000 x 10^6 gal), about 42 x 10^6 m^3 are required for this purpose, assuming that these plants use once-through cooling. Other water uses involve the discharge to air (e.g., evaporation losses in process cooling) of about 0.6 x 10^6 m^3 per year and water discharged to ground (e.g., mine drainage) of about 0.5 x 10^6 m^3 per year.

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*A notice of final rulemaking proceedings was given in the *Federal Register* of May 26, 1977 (42 FR 26987) that calls for additional public comment before adoption or final modification of the interim rule.

†A narrative explanation of Table 5.8 (Table S-3) was published in the *Federal Register* (46 FR 15154-75) on March 4, 1981.

‡A coal-fired power plant of 1000 MWe capacity using strip-mined coal requires the disturbance of about 81 ha (200 acres) per year for fuel alone.

Table 5.8. Summary of environmental considerations for uranium fuel cycle[a]

Normalized to model LWR annual fuel requirement (WASH-1248) or reference reactor year (NUREG-0116)

Natural resource use	Total	Maximum effect per annual fuel requirement or reference reactor year of model 1000-MWe LWR
Land, acres		
Temporarily committed[b]	100	
Undisturbed area	79	
Disturbed area	22	Equivalent to 110-MWe coal-fired power plant
Permanently committed	7.1	
Overburden moved, millions of metric tons	2.8	Equivalent to 95-MWe coal-fired power plant
Water, millions of gallons		
Discharged to air	160	Equals 2% of model 1000-MWe LWR with cooling tower
Discharged to water bodies	11,090	
Discharged to ground	127	
Total	11,377	Less than 4% of model 1000-MWe LWR with once-through cooling
Fossil fuel		
Electrical energy, thousands of megawatt hours	321	Less than 5% of model 1000-MWe LWR output
Equivalent coal, thousands of metric tons	117	Equivalent to the consumption of a 45-MWe coal-fired power plant
Natural gas, millions of standard cubic feet	135	Less than 0.3% of model 1000-MWe energy output
Effluents — chemical, metric tons		
Gases (including entrainment)[c]		
SO_x	4,400	
NO_x[d]	1,190	Equivalent to emissions from 45-MWe coal-fired power plant for a year
Hydrocarbons	14	
CO	29.6	
Particulates	1,154	
Other gases		
F^-	0.67	Principally from UF_6 production, enrichment, and reprocessing. Concentration within range of state standards — below level that has effects on human health
HCl	0.014	
Liquids		
SO_4^{2-}	9.9	From enrichment, fuel fabrication, and reprocessing steps. Components that constitute a potential for adverse environmental effect are present in dilute concentrations and receive additional dilution by receiving bodies of water to levels below permissible standards. The constituents that require dilution and the flow of dilution water are:
NO_3^-	25.8	
Fluoride	12.9	
Ca^{2+}	5.4	
Cl^-	8.5	NH_3 — 600 cfs
Na^+	12.1	NO_3 — 20 cfs
NH_3	10.0	*Fluoride — 70 cfs*
Fe	0.4	
Tailings solutions, thousands of metric tons	240	From mills only — no significant effluents to environment
Solids	91,000	Principally from mills — no significant effluents to environment
Effluents — radiological, curies		
Gases (including entrainment)		
Rn-222		Presently under reconsideration by the Commission
Ra-226	0.02	
Th-230	0.02	
Uranium	0.034	
Tritium, thousands	18.1	
C-14	24	
Kr-85, thousands	400	
Ru-106	0.14	Principally from fuel reprocessing plants
I-129	1.3	
I-131	0.83	
Tc-99	0.203	Presently under consideration by the Commission
Fission products and transuranics		
Liquids		
Uranium and daughters	2.1	Principally from milling — included in tailings liquor and returned to ground — no effluents; therefore, no effect on environment
Ra-226	0.0034	From UF_6 production
Th-230	0.0015	
Th-234	0.01	From fuel fabrication plants — concentration 10% of 10 CFR Part 20 for total processing 26 annual fuel requirements for model LWR
Fission and activation products	5.9×10^{-6}	
Solids (buried on site)		
Other than high level (shallow)	11,300	9100 Ci come from low-level reactor wastes and 1500 Ci come from reactor decontamination and decommissioning — buried at land burial facilities. Mills produce 600 Ci — included in tailings returned to ground; about 60 Ci come from conversion and spent-fuel storage. No significant effluent to the environment
TRU and HLW (deep)	1.1×10^7	Buried at Federal repository
Effluents — thermal, billions of British thermal units	4.063	Less than 4% of model 1000-MWe LWR
Transportation, person-rems	2.5	
Exposure of workers and general public		
Occupational exposure, person-rems	22.6	From reprocessing and waste management

[a] In some cases where no entry appears, it is clear from the background documents that the matter was addressed and that, in effect, this table should be read as if a specific zero entry had been made. However, there are other areas that are not addressed at al in this table. Table S-3 of WASH-1248 does not include health effects from the effluents described in this table or estimates of releases of Radon-222 from the uranium fuel cycle. These issues which are not addressed at all by this table may be the subject of litigation in individual licensing proceedings. Data supporting this table are given in the *Environmental Survey of the Uranium Fuel Cycle*, WASH-1248, April 1974; the *Environmental Survey of the Reprocessing and Waste Management Portions of the LWR Fuel Cycle*, NUREG-0116 (Suppl. 1 to WASH-1248); and the *Discussion of Comments Regarding the Environmental Survey of the Reprocessing and Waste Management Portions of the LWR Fuel Cycle*, NUREG-0216 (Suppl. 2 to WASH-1248). The contributions from reprocessing, waste management, and transportation of wastes are maximized for either of the two fuel cycles (uranium only and no-recyle). The contribution from transportation excludes transportation of coal fuel to a reactor and of irradiated fuel and radioactive wastes from a reactor which are considered in Table S-4 of Sect. 51.20(g). The contributions from the other steps of the fuel cycle are given in columns A — E of Table S-3A of WASH-1248.

[b] The contributions to temporarily committed land from reprocessing are not prorated over 30 years, because the complete temporary impact accrues regardless of whether the plant services 1 reactor for 1 year or 57 reactors for 30 years.

[c] Estimated effluents based on combustion of equivalent coal for power generation.

[d] 1.2% from natural gas use and process.

On a thermal effluent basis, annual discharges from the nuclear fuel cycle are about 4% of those from the model 1000 MWe LWR using once-through cooling. The consumptive water use of 0.6×10^6 m^3 per year is about 2% of that of the model 1000 MWe LWR using cooling towers. The maximum consumptive water use (assuming that all plants supplying electrical energy to the nuclear fuel cycle used cooling towers) would be about 6% of that of the model 1000 MWe LWR using cooling towers. Under this condition, thermal effluents would be negligible. The staff finds that these combinations of thermal loadings and water consumption are acceptable relative to the water use and thermal discharges of the proposed project.

Electrical energy and process heat are required during various phases of the fuel-cycle process. The electrical energy is usually produced by the combustion of fossil fuel at conventional power plants. Electrical energy associated with the fuel cycle represents about 5% of the annual electrical power production of the model 1000 MWe LWR. Process heat is primarily generated by the combustion of natural gas. This gas consumption, if used to generate electricity, would be less than 0.3% of the electrical output from a 1000 MWe plant. The staff finds that the direct and indirect consumption of electrical energy for fuel-cycle operations are small and acceptable relative to the net power production of the proposed project.

The quantities of chemical, gaseous, and particulate effluents with fuel-cycle processes are given in Table 5.8. The principal species are SO_x, NO_x, and particulates. The staff finds, on the basis of data in a Council on Environmental Quality report,[24] that these emissions constitute an extremely small additional atmospheric loading in comparison with these emissions from the stationary fuel-combustion and transportation sectors in the U.S., i.e., about 0.02% of the annual national releases for each of these species. The staff believes such small increases in releases of these pollutants are acceptable.

Liquid chemical effluents produced in fuel-cycle processes are related to fuel-enrichment, -fabrication, and -reprocessing operations and may be released to receiving waters. These effluents are usually present in such dilute concentrations that only small amounts of dilution water are required to reach levels of concentration that are within established standards. Table 5.8 specifies the flow of dilution water required for specific constituents. Additionally, all liquid discharges into the navigable waters of the United States from plants associated with the fuel-cycle operations will be subject to requirements and limitations set forth in an NPDES permit issued by an appropriate state or Federal regulatory agency.

Tailings solutions and solids are generated during the milling process. These solutions and solids are not released in quantities sufficient to have a significant impact on the environment.

Radioactive effluents estimated to be released to the environment from reprocessing and waste management activities and certain other phases of the fuel-cycle process are set forth in Table 5.8. Using these data, the staff has calculated the 100-year involuntary environmental dose commitment* to the U.S. population. These calculations estimate that the overall involuntary total body gaseous dose commitment to the U.S. population from the fuel cycle (excluding reactor releases and the dose commitment due to radon-222) would be approximately 400 man-rems per year of operation of the model 1000 MWe LWR. The additional involuntary total body dose commitment to the U.S. population from radioactive liquid effluents due to all fuel-cycle operations other than reactor operation, estimated on the basis of the values given in Table 5.8, would be approximately 100 man-rems per year of operation. Thus, the estimated involuntary 100-year environmental dose commitment to the U.S. population from radioactive gaseous and liquid releases due to these portions of the fuel cycle is approximately 500 man-rems (whole body) per year of operation of the model 1000 MWe LWR.

At this time Table 5.8 does not address the radiological impacts associated with radon-222 releases. Principal radon releases occur during mining and milling operations and, following completion of mining and milling, as emissions from stabilized mill tailings and from unreclaimed open-pit mines. The staff has determined that releases from these operations for each year of operation of the model 1000 MWe LWR are as follows:

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*The environmental dose commitment (EDC) is the integrated population dose for 100 years; i.e., it represents the sum of the annual population doses for a total of 100 years. The population dose varies with time, and it is not practical to calculate this dose for every year.

Mining: (during active mining)[25]	4060 Ci
Mining: (unreclaimed open-pit mines)[26]	30 to 40 Ci/year
Milling and Tailings:[27] (during active milling)	780 Ci
Inactive Tailings:[27] (prior to stabilization)	350 Ci
Stabilized Tailings:[27] (several hundred years)	1 to 10 Ci/year
Stabilized Tailings:[27] (after several hundred years)	110 Ci/year

The staff has calculated population dose commitments for these sources of radon-222 using the RABGAD computer code described in Section IV.J of Appendix A of NUREG-0002.[28] The results of these calculations for mining and milling activities prior to tailings stabilization are shown in Table 5.9.

Table 5.9. Estimated 100-year environmental dose commitment per year of operation of the model 1000 MWe LWR

Radon-222 releases		Dose commitments (man-rems)		
Source	Amount (Ci)	Total body	Bone	Lung (bronchial epithelium)
Mining	4100	110	2800	2300
Milling and active tailings	1100	29	750	620
Total		140	3600	2900

When added to the 500 man-rem total body dose commitment for the balance of the fuel cycle, the overall estimated total body involuntary 100-year environmental dose commitment to the U.S. population from the fuel cycle for the model 1000 MWe LWR is approximately 600 man-rems. Over this period of time, this dose is equivalent to 0.00002% of the natural background dose of about 3,000,000,000 man-rems to the U.S. population.*

The staff has considered health effects associated with the releases of radon-222, including both the short-term effects of mining, milling, and active tailings and the potential long-term effects from unreclaimed open-pit mines and stabilized tailings. After completion of active mining, the staff has assumed that underground mines will be sealed, with the result that releases of radon-222 from them will return to background levels. For purposes of providing an upper-bound impact assessment, the staff has assumed that open-pit mines will be unreclaimed and has calculated that if all ore were produced from open-pit mines, releases from them would be 110 Ci/year of operation of the model 1000 MWe LWR. However, since the distribution of uranium ore reserves available by conventional mining methods is 66.8% underground and 33.2% open pit,[29] the staff has further assumed that uranium to fuel LWRs will be produced by conventional mining methods in these proportions. This means that long-term releases from unreclaimed open-pit mines will be 0.332 x 110 or 37 Ci/year of operation of the model LWR.

On the basis of these assumptions, the radon released from unreclaimed open-pit mines over 100- and 1000-year periods can be calculated to be about 3700 Ci and 37000 Ci/year of operation of the model reactor, respectively. The total dose commitments for a 100-1000-year period would be as follows:

*Based on an annual average natural background individual dose commitment of 100 mrem and a stabilized U.S. population of 300 million.

Time span	Total release	Population dose commitments (man-rems)		
		Total body	Bone	Lung (brochial epithelium)
100 years	3,700	96	2,500	2,000
500 years	19,000	480	13,000	11,000
1,000 years	37,000	960	25,000	20,000

The above dose commitments represent a worst-case situation since no mitigation circumstances are assumed. However, state and Federal laws currently require reclamation of strip and open-pit coal mines, and it is very probable that similar reclamation will be required for uranium open-pit mines. If so, long-term releases from such mines should approach background levels.

For long-term radon releases from stabilized tailings piles, the staff has assumed that these tailings would emit, per year of operation of the model 1000 MWe LWR, 1 Ci/year for 100 years, 10 Ci/year for the next 400 years, and 100 Ci/year for periods beyond 500 years. With these assumptions, the cumulative radon-222 release from stabilized tailings piles per operating year of the model reactor will be 100 Ci in 100 years, 4,090 Ci in 500 years, and 53,800 Ci in 1000 years[30]. The total body, bone, and bronchial epithelium dose commitments for these periods are as follows:

Time span	Total release	Population dose commitments (man-rems)		
		Total body	Bone	Lung (brochial epithelium)
100 years	100	2.6	68	56
500 years	4,090	110	2,800	2,300
1,000 years	53,800	1,400	37,000	30,000

Using risk estimators of 135, 6.9, and 22.2 cancer deaths per million man-rems for total body, bone, and lung exposures, respectively, the estimated risk of cancer mortality due to mining, milling, and active tailings emissions of radon-222 would be about 0.11 cancer fatalities per operating year of the model 1000 MWe LWR. When the risk due to radon-222 emissions from stabilized tailings over a 100-year release period is added, the estimated risk of cancer mortality over a 100-year period is unchanged. Similarly, a risk of about 1.2 cancer fatalities is estimated over a 1000-year release period per operating year of the model 1000 MWe LWR. When potential radon releases from reclaimed and unreclaimed open-pit mines are included, the overall risks of radon induced cancer fatalities per operating year of the model 1000 MWe LWR would range as follows:

0.11-0.19 fatalities for a 100-year period

0.19-0.57 fatalities for a 500-year period

1.2-2.0 fatalities for a 1000-year period

To illustrate: A single model 1000 MWe LWR operating at an 80% capacity factor for 30 years would be predicted to induce between 3.3 and 5.7 cancer fatalities in 100 years, 5.7 and 17 in 500 years, and 36 and 60 in 1000 years as a result of releases of radon-222.

These doses and predicted health effects have been compared with those that can be expected from natural-background emissions of radon-222. Using data from the National Council on Radiation Protection[31], the average radon 222 concentration in air in the contiguous United States is about 150 pCi/m^3, which the NCRP estimates will result in an annual dose to the bronchial epithelium of 450 mrem. For a stabilized future U.S. population of 300 million, this represents a total lung dose commitment of 135 million man-rems per year. Using the same risk estimator of 22.2 lung cancer fatalities per million man-lung-rems used to predict cancer fatalities for the model 1000 MWe LWR, estimated lung cancer fatalities alone from background radon-222 in the air can be calculated to be about 3000 per year or 300,000 to 3,000,000 lung cancer deaths over periods of 100 and 1,000 years respectively.

Other nuclides produced in the cycle, such as carbon-14, will contribute to population exposures in addition to the radon-related potential health effects from the fuel cycle. It is estimated that 0.08 to 0.12 additional cancer deaths may occur per operating year of the model 1000 MWe LWR (assuming that no cure or prevention of cancer is ever developed) over the next 100 to 1000 years, respectively, from exposures to these other nuclides.

These latter exposures can also be compared with those from naturally-occurring terrestrial and cosmic-ray sources, which average about 100 mrem. Therefore, for a stable future population of 300 million persons, the whole-body dose commitment would be about 30 million man-rems per year, or 3 billion man-rems and 30 billion man-rems for periods of 100 and 1000 years respectively. These dose commitments could produce about 400,000 and 4,000,000 cancer deaths during the same time periods. From the above analysis, the staff concludes that both the dose commitments and health effects of the uranium fuel cycle are insignificant when compared to dose commitments and potential health effects to the U.S. population resulting from all natural background sources.

5.6 SOCIOECONOMIC IMPACTS

5.6.1 Introduction

A 96-km (60-mile) radius of the San Onofre site circumscribes most of the metropolitan areas of Los Angeles and San Diego, the third and fourteenth largest cities, respectively, in the United States. Between 1970 and 1980, San Diego County had a 37.1% increase in population, reaching a total of 1,861,846 in 1980 and a density of about 170/km^2 (438/m^2).

Continued growth within 96 km (60 miles) of the San Onofre site is expected for the next three decades. The central portion of Orange County and the city of San Diego and its immediate environs are projected to be the major growth areas (ER, Sect. 2.1.3.2.2). The population growth rates within 16 km (10 miles) of the site are expected to fluctuate over the operating life of SONGS 2 and 3. The annual growth rate between 1976 and 1980 is expected to be 4.2%, decreasing to 0.3% between 1990 and 2000, and rising to 1.1% between 2010 and 2020 (ER, Sect. 2.1.3.1.1).

5.6.2 Impact of the construction labor force

A peak labor force of about 3000 workers was employed at SONGS 2 and 3 in late 1979. Of this number, the applicant has estimated that about 600 workers (20% of the peak labor force) have relocated to the southern California area (Sect. 2.2.3). Although the staff could not determine the exact location of these workers, current growth projections for the area indicate that the addition of 600 workers represents an insignificant impact. Between 1976 and 1980 the population in the area that is 16 to 80 km (10 to 50 miles) from the site was projected to increase 2.2% (ER, Sect. 2.1.3.2.1). The addition of 600 workers accounts for less than 0.1% of the growth expected during that time period.

Staff interviews with local and regional officials indicated that construction of SONGS 2 and 3 has had no impact on cities within 24 km (15 mi) of the site. Representatives of Southern California Association of Governments stated that it was doubtful that any significant impact attributable to plant construction could be identified in Orange County. The facts that (1) the majority of the work force commuted to site, (2) there was widespread busing to and from Orange County, Oceanside, Vista, Escondido, and San Diego, and (3) the region is currently experiencing rapid population growth support the staff's judgment that no significant social impact has occurred or is likely to occur due to in-migration of construction workers.

Cessation of large construction projects can result in varying degrees of economic dislocation to an area, especially if a previously underdeveloped commercial and service structure is expanded to meet the requirements of a large, short-term population influx. The southern California area has a well-developed infrastructure; thus, ending the construction phase of SONGS 2 and 3 is not expected to produce significant economic dislocation.

5.6.3 Impact of the operating labor force

The operation of SONGS 2 and 3 will employ about 200 workers. Table 5.10 provides an estimate for typical operating personnel requirements and types of employment positions at a two-unit pressurized-water reactor (PWR). The operations positions will be filled first by current members of I.B.E.W. Local No. 246. Positions unfilled will be offered to all Southern California Edison (SCE) employees, and if the position remains unfilled, SCE will advertise in local and regional newspapers (ER, p. S.2-175). Because of the diversified labor markets of Los Angeles and San Diego, the staff believes that at least 75% of these workers can be hired from within a 96-km (60-mile) radius of the site.

The applicant conducted surveys in March 1976 to determine the residential location of SONGS 1 workers. Seventy-five percent of these workers lived within 40 km (25 miles) of the San Onofre site, and 65% resided in Orange County, 30% in San Diego County, and 5% in Los Angeles and Riverside counties (ER, Appendix 8A, p. 10). The surveys further indicated that the cities of Carlsbad, Oceanside, San Clemente, San Juan Capistrano, and Vista were the major

Table 5.10. Operating personnel for a two-unit PWR

1 Plant superintendent	Warehouse staff
1 Assistant plant superintendent	1 Superintendent
2 Safety engineers	1 Assistant superintendent
	5 Clerks
Quality assurance staff	1 Truck driver
1 Superintendent	Engineering section
4 Engineers	1 Superintendent
5 Engineering aides	3 Instrument engineers
	3 Instrument engineering aides
Administrative services	2 Senior instrument mechanic foremen
1 Superintendent	20 Mechanics
1 Assistant superintendent	2 Mechanical engineers
3 Payroll clerks	3 Mechanical engineering aides
9 Stenographers and file clerks	1 Reactor engineer
7 Janitors	1 Reactor engineering aide
	2 Nuclear engineers
1 Industrial engineer	1 Chemical engineer
1 Nurse	9 Chemical engineering aides
Health physics staff	Maintenance staff
1 Superintendent	1 Superintendent
2 Technicians	1 Assistant superintendent (electrical)
1 Clerk	1 Assistant superintendent (mechanical)
	2 Mechanical maintenance engineers
Security staff	1 Electrical maintenance engineer
1 Superintendent	3 Engineering aides
1 Assistant superintendent	
9 Security officers	Trades and labor staff
	1 Machinist foreman
Operations	11 Machinists
Control room staff	1 Boiler-maker foreman
1 Superintendent	5 Boiler makers
1 Assistant superintendent	1 Steam-fitter foreman
1 Training coordinator	12 Steam fitters
5 Clerks	1 Electrician foreman
6 Shift engineers	10 Electricians
10 Assistant shift engineers	1 Labor foreman
15 Unit operators	10 Laborers
18 Assistant unit operators	2 Truck drivers
	2 Carpenters
Communications engineering staff	2 Sheet metal workers
2 Engineers	2 Painters
3 Engineering aides	2 Insulators
	1 Structural iron worker

Source: Tennessee Valley Authority, Department of Planning, Chattanooga, Tenn., 1977.

communities of worker residence. The staff estimates that approximately the same pattern of location will occur with SONGS 2 and 3 workers as occurred with SONGS 1 workers.

Between 1973 and 1980, northern San Diego County was expected to have a population increase of about 22,000. From 1975 to 1980 southern Orange County was projected to grow by about 21,000 persons. Assuming that all operations workers relocated to the area, the staff concludes that the addition of 200 workers and their households represents a negligible effect.

The staff cannot determine precisely the number of workers who will (1) relocate from outside the area or (2) choose to move from within the 96-km (60-mile) radius to a residence closer to the plant. In order to predict the maximum possible impact on housing in the area, the staff assumes that all of the workers will relocate and thus require housing. A relocating operations force will likely demand permanent housing. From Table 5.11, it appears that housing availability in Orange and San Diego counties is sufficient to provide diversity in location for all operations workers' households. The table further indicates that, based on the number of vacant units in 1976, a surplus of housing exists in each of the communities expected to house workers.

Estimates on the location of SONGS 1 worker indicate SONGS 2 and 3 households will likely contribute to increased enrollments in the school districts of Carlsbad, Capistrano, Oceanside, Saddleback Valley, and Vista. The total additional enrollment at all five school districts

Table 5.11. Housing availability in Orange and San Diego counties

Communities	Residential distribution of households SONGS 2 & 3	Number of existing dwelling units as of Jan. 1, 1976	Number of vacant units as indicated by number of idle electric meters for Jan. 1, 1976
Orange County total	127	592,932	10,080
San Clemente	32	10,636	170
San Juan Capistrano	41	4,561	73
Saddleback (Irvine)	22	11,102	178
Other unincorporated areas	32	76,260	1,220
San Diego County total	61	547,708	8,763
Carlsbad	11	9,111	200
Oceanside	25	20,835	458
Vista	20	12,539	276
Other unincorporated areas	5	108,841	2,395

Source: ER, Suppl. 2, Table 89-A, p. S.2-178.

will be about 105 students (ER, Appendix A, p. 20). The community college districts of Oceanside-Carlsbad, Palomar, and Saddleback will likely increase their enrollments by approximately 20 to 25 students (ER, Appendix 8A, p. 20). The staff concludes that this estimated increased enrollment represents a negligible impact on the school districts.

Operations employment at SONGS 2 and 3 will be relatively high-paying, stable work. About 87% of the total work force will have gross incomes in excess of $15,000 per year (ER, Appendix 8A, p. 15). The annual average income in 1976 dollars for a SONGS 2 and 3 household will be about $20,800. This compares to a median family income in 1980 for San Diego and Orange counties of $21,500 and $26,200 respectively. SONGS 2 and 3 households are expected to contribute to the economic activity of the area. Total taxable retail expenditures by households of operations employees are estimated to be about $855,000 per year (ER, p. S.2-176). In addition, those workers who build homes will contribute further to the economic activity of the area.

5.6.4 Economic impacts

The staff believes that the major economic impact associated with the operation of SONGS 2 and 3 will be a result of tax revenues generated by the plant. These taxes include property tax, state income tax, utility users tax, franchise tax payments, and sales and use taxes. The analysis presented here differs from that presented earlier in the DES by taking into account the impacts of the Jarvis-Gann Amendment (Proposition 13). The following discussion is based on two important assumptions. (1) The method of determining the value of state-regulated utility systems, currently before the State Court of Appeals, will be decided in accordance with the decision of the State Board of Equalization. Accordingly, SONGS 2 and 3 will be assessed on current market value, based on historical methods of valuation rather than on the 1975-76 base year as prescribed in Proposition 13. (2) The allocation of tax revenues among the various funds and districts within the county will remain roughly the same as at present.[32] Changes in either of the above conditions in the future may result in significant variation from the situation described here.

Under Proposition 13, neither the assessed value of the SONGS 2 and 3 units nor their annual tax liability differs greatly from the figures presented in the DES. Earlier projections were for an assessed valuation of $348 million in 1976 dollars (ER, Appendix 8-A, p. 4) and an annual property tax payment of $13.1 million (DES, Sect. 5.6.4). Current calculations show an eventual assessed value of $326 million in 1979 dollars and an annual tax of approximately $13 million (Table 5.12). At present, current construction at SONGS 2 and 3 is already assessed at roughly $100 million and is generating $4 million yearly in property tax revenues. The remaining $9 million in property taxes will be added as construction is completed.[32]

While the total tax burden is not significantly different under the terms of Proposition 13, the distribution of the resulting revenues is. Previously, it was projected that nearly all of the $13 million in property taxes generated by SONGS 2 and 3 would go to the County General Fund, the County Library Fund, and three local school districts in the immediate vicinity of the plant – Fallbrook Union Elementary, Fallbrook Union High, and Palomar Community College (DES,

Table 5.12. Projected impacts of SONGS 2 & 3 on San Diego County property tax revenues

	San Diego County	SONGS 2 & 3	Total: County plus SONGS 2 & 3	SONGS 2 & 3 as % of total
Assessed value	$7,775.5 million[1]	$326 million[3]	$8,101.5 million	4.0%
Annual taxes	$311 million[2]	$13 million[3]	$324 million	4.0%

[1]For FY 1978-79, not counting $100 million of SONGS 2 & 3 construction currently on tax rolls.
[2]For FY 1978-79, not counting $4 million currently received for SONGS 2 & 3 construction.
[3]As of project completion, in 1979 dollars.
Source: Letter from J. H. Drake, Southern California Edison Co., to W. H. Regan, Jr., U.S. NRC, dated April 17, 1979.

Sect. 5.6.4). Now, however, the new revenues will be distributed throughout the county on the basis of the historical property tax revenue relationships between all the various funds and districts. Accordingly, the five entities named above will receive roughly one-fourth of the plant-induced taxes, or $3.4 million, because this is the proportion of all county funds they have traditionally received. The remaining $9.6 million will go to other recipients county-wide. Because of this widespread distribution, the property taxes paid by SONGS 2 and 3 will not bring a large windfall to any single district but, rather, a modest 4.0% increase to all county funds and districts over pre-construction receipts (2.9% over the present situation where $100 million of plant construction is already on the tax rolls). The debt service rate of the three previously named school districts will be reduced as a result of plant induced revenues but this represents a very small part of the total property tax.[32]

Sales and use taxes payable to the State of California are levied at 6% of the retail or use value of fixtures, equipment, machinery, and materials purchased either in or outside of the State of California and placed in use within the state. For every 6 cents collected, 1.25 cents is allocated to counties and cities. The state tax on nuclear fuel for SONGS 2 and 3 is expected to be about $2.5 million per year. In addition, $415,000 in sales tax for materials will be paid in 1981, the first year of operation (ER, Appendix 8A, p. 8).

Over the operating life of SONGS 2 & 3, about $66 million in California state corporate income taxes will be paid by the applicant. California also has a City Utility Users Tax that, although it is difficult to determine the proportion for which SONGS 2 & 3 are directly responsible, is estimated to increase by $1.6 million per year (ER, Appendix 8A, p. 8). This tax varies for each city, and the revenues are not earmarked for any particular purposes.

The California Energy Resources Surcharge is included in the retail customer's bill and is collected by the utility. The current surcharge is $0.00015 per kilowatt-hour. The revenues collected are placed in the State Energy Resources Conservation and Development Special Account in the General Fund in the State Treasury by the State Board of Equalization. All funds in the account are to be expended for the purpose of carrying out the provisions of the Warren-Alquist State Energy Resources Conservation and Development Act.

5.6.5 Impact on recreational resources

In the early 1960s the applicant secured a leasehold from the U.S. Marine Corps at Camp Pendleton. During construction of SONGS 1, the Marine Corps released about 5.6 km (3.5 miles) of beach front to the State of California to be maintained as San Onofre State Beach. When this park opened in 1971, an additional 2440 m (8000 ft) of beach front had gained public access. Of this, 1370 m (4500 ft) are on the applicant's leasehold and the remaining 1070 m (3500 ft) are immediately north of the plant site, comprising another section of the state beach.

In order to comply with NRC regulations regarding the siting of nuclear power plants set forth in 10 CFR Part 100, the applicant proposes to control recreational activities on the beach for a distance of about 1.4 km (0.85 mile) adjacent to the station (ER, Sect. 2.1.2). Access to this area will be permitted for the purpose of viewing the barrancas and bluffs south of the station and for pedestrian passage between the public beach areas north and south of the station. Recreational activities, such as sunbathing or picnicking, will not be permitted within the landward portion of this restricted area. To facilitate passage between the beaches, a walkway will be constructed through the restricted area adjacent to the seawall. This walkway will be 4.6 m (15 ft) wide, will be bounded by a 2.4-m (8-ft) chain link fence, and will be used only for passage through the restricted area. It is the judgment of the staff that the fence proposed by the applicant is inappropriate in light of the scenic nature of the area and that a less aesthetically objectionable way should be

sought to restrict access to the beach. Therefore, it is recommended that the applicant consider alternate methods of beach enclosure that will safely restrict access in a manner compatible with the scenic nature of this area.

In the Final Environmental Statement required for the construction permit of SONGS 2 and 3, the staff stated, "Use of the beach will not be restricted after construction is complete" (FES-CP, p. 2-11). The current plan to restrict use of approximately 1.4 km (0.85 mile) of the beach front for the 30-year operating life of the plant is a significant loss of valuable recreational and scenic space and represents a substantial change in action between issuance of the FES-CP and application for an operating license. The staff further stated, "The beach in the vicinity of the Station (5639 m (18,500 ft) south and 1036 m (3400 ft) north) is considered to be a unique and scarce recreational resource," (FES-CP, p. 2-11) and "Closure for even a brief period is objectionable" (FES-CP, p. 8-1). The loss of this resource precludes recreational benefits to significant numbers of beach users in the vicinity of San Onofre Beach. The staff reiterates those judgments and concludes that the current plan to restrict the public's use of this beach is a significant cost of the project, unanticipated at issuance of the construction permit. This impact is not sufficiently adverse, however, to warrant denying an operating license.

While all state beaches in the Pendleton coast area experienced increased usage in recent years, the attendance at San Onofre State Beach has risen significantly faster than at the other facilities. Between 1972 and 1978, the annual number of visits to the San Onofre State Beach rose by 98% while San Clemente and Doheny State Beaches showed increases of 46% and 25%, respectively (ER, Appendix 8A, Table 24, and Reference 32). As demand on available recreational resources increases, the significance of removing the beach in front of SONGS 2 & 3 from unrestricted public use will increase.

5.6.6 Emergency planning impacts

The applicants are currently revising the Emergency Plan, San Onofre Nuclear Generating Station Units 2 and 3 in accordance with 10 CFR Part 50, as amended July 23, 1980, as well as the recommended criteria contained in NUREG-0654. The staff believes the only noteworthy potential source of impact on the public from emergency planning would be associated with the siren alert system. The system will be designed to provide a minimum 10db dissonant differential from the ambient noise levels. The maximum sound level received by any member of the public should be lower than 123db. A complete cycle test will be required annually. The test requirements and alarm noise levels are consistant with those used for existing alert systems; therefore the staff concludes that the noise impacts associated with the siren alert system will be infrequent and insignificant.

5.6.7 Summary and conclusion

The staff concludes that, with the significant exception of restricting public use of 1.4 km (0.85 mi) of the San Onofre beach, the social and economic impact of operating SONGS 2 & 3 will be moderate. The large population within 96 km (60 miles) of the site and the projected population growth in the area is such that the addition of all 200 workers and their families would represent negligible impact to the area. Under the terms of Proposition 13, the property tax revenues received by the various funds and districts in San Diego County will be relatively small in proportion to existing revenues.

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* Available for inspection and copying for a fee in the NRC Public Document Room, 1717 H St., NW., Washington, DC 20555.

** Available from the NRC/GPO Sales Program, Washington, DC 20555, or the National Technical Information Service, Springfield, VA 22161.

***Available from NTIS only.

6. ENVIRONMENTAL MONITORING

6.1 SUMMARY

The applicant has expanded its San Onofre Unit 1 environmental monitoring program (biological, chemical, physical, and thermal) to determine environmental effects which may occur as a result of site preparation and construction of Units 2 and 3 and to establish an adequate preoperational baseline by which the operational effects of Units 2 and 3 may be judged.

The aquatic preoperational environmental monitoring program for SONGS 2 and 3 was approved by NRC and implemented by the applicant in April 1978. The NRC-approved program terminated in September 1980. However, all NPDES permit monitoring program requirements will continue to be met until an approved operational monitoring program is implemented. Results of the preoperational monitoring program will be used in formulating the operational monitoring program, which the applicant will submit for approval by the California Regional Water Quality Control Board to be incorporated in the NPDES permit monitoring program.

The environmental monitoring programs presented here differ somewhat from the description in the FES-CP. More detailed information is given here than in the FES-CP. Two state agencies, the California Regional Water Quality Control Board and the California Coastal Commission, have imposed environmental monitoring requirements in the vicinity of the San Onofre Station. NRC has discussed the results of its environmental review with the State agencies and has provided the State with recommendations for monitoring. The sections which follow include NRC staff recommendations based on its environmental review. However, requirements for non-radiological monitoring of the aquatic environment will be the responsibility of the State.

6.2 PREOPERATIONAL ENVIRONMENTAL PROGRAMS

The results from the preoperational monitoring program for Units 2 and 3 will be submitted with the Annual Operating Report for Unit 1.

6.2.1 Aquatic biological monitoring program

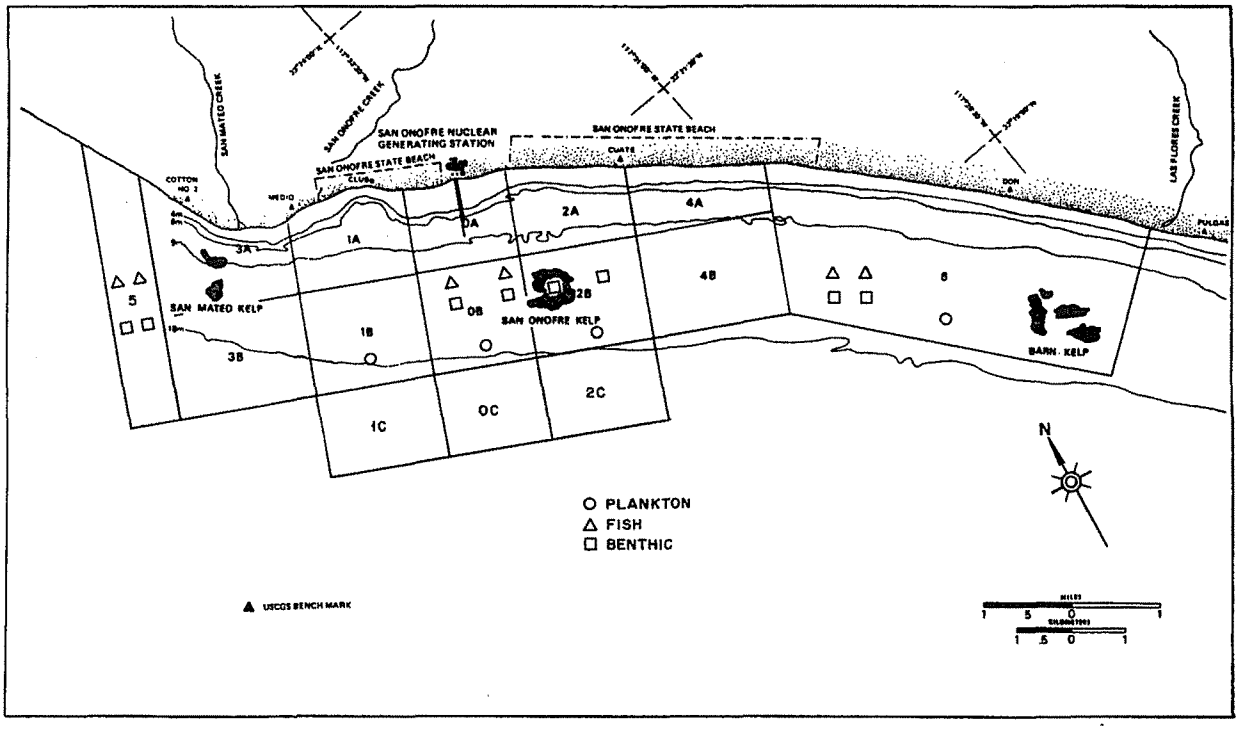
The applicant's preoperational aquatic biological monitoring program was designed to determine the species composition, abundance, and the temporal and spatial distribution of phytoplankton, zooplankton, ichthyoplankton, nekton, benthos, kelp beds, and intertidal organisms. The data obtained will be used to provide a basis for comparison with future operational monitoring data to determine if plant operation has caused observable perturbations in the ecosystem.

The possible operational impacts identified in this document and the FES-CP include: changes in local plankton populations due to entrainment; changes in the abundance of fish eggs, larvae, juveniles, and adults due to entrainment; adult fish population shifts due to fish impingement; alterations in some of the benthic and fish communities from thermal discharges; and changes in benthic and planktonic communities from increased turbidity. Thus, results from the preoperational and operational monitoring programs will be used to determine the extent to which the above effects occur.

6.2.1.1 Phytoplankton and zooplankton

Phytoplankton and zooplankton were sampled bimonthly. Samples were collected from at least four fixed stations, one each in zones 0B, 1B, 2B and 6 (Figure 6.1). A pump system is used to sample the water column and a 202 μm mesh-size screen is used to collect the zooplankton. Zooplankton biomass is determined and predominant species are enumerated. Chlorophyll analyses are performed on whole-water samples. Collections are coordinated, as much as possible, with the collection of pertinent physical data such as temperature, transparency, and current velocity and direction.

ES-4559



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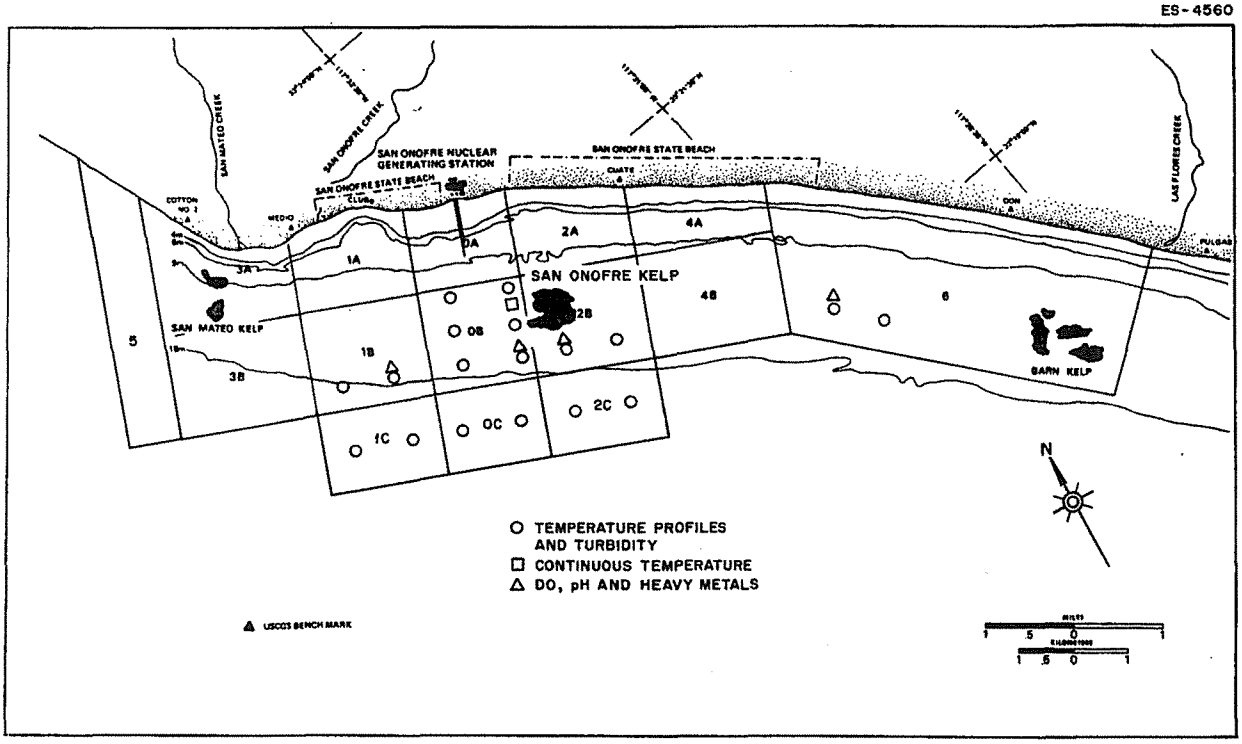

Fig. 6.1. Environmental monitoring stations for SONGS 2 and 3 preoperational monitoring program. Source: ER, Apendix 6A, Figs. 1 and 2.

The staff recommends that predominant phytoplankton genera also be enumerated to provide baseline conditions for this group. This would enable, for example, the determination of whether operation of the facility promotes red tide development (see Sect. 5.3.2, FES-CP).

6.2.1.2 Ichthyoplankton

Ichthyoplankton will be collected monthly at two stations in the Units 2 and 3 discharge area, zone OB, and at two stations in the reference area, either zone 5 or 6. Additionally, the Unit 1 intake area will be sampled. The study began approximately two years prior to initial operation of Unit 2 and lasted one year. Sampling was conducted during the day, at night, at dawn, and at dusk at the intake; night sampling was employed at the other locations. The water surface, water column, and epibenthos was sampled at each station. Fish larvae were identified to the lowest taxon possible and enumerated. Fish eggs were sorted and enumerated.

A study by the Marine Review Committee (MRC) was initiated in July 1976 (see Section 6.4.2) to assess the distribution, abundance, and entrainment of ichthyoplankton at SONGS 1. It is expected that data acquired from this work will also help characterize the SONGS 2 and 3 environment.

6.2.1.3 Nekton

Replicate fish samples were collected on a quarterly basis from at least two stations in zone OB, two in zone 5, two in the control zone, zone 6 (Figure 6.1). The gill nets used were 2- by 46-m (6- by 150-ft) full size, containing six 7.5-m (25-ft) panels of 19.05-, 25.4-, 31.75-, 38.1-, 44.5-, and 63.5-mm (3/4-, 1-, 1-1/4-, 1-1/2-, 1-3/4-, and 2-1/2-in.) bar mesh. The fish were measured, their state of health was assessed, and sexual maturation was determined on subsamples. Synoptic measurements of temperature and transmissivity were taken at each station.

6.2.1.4 Benthos

Benthic samples were collected quarterly at at least two stations within each of zones OB, 2B, 6 and 5 (or zones 3A and/or 3B) (Fig. 6.1). Permanent sampling stations exist in which a 6-m^2 (64.56-ft^2) sampling area has been established. Each sampling area contains 300 evenly spaced contact points which are used to estimate the distribution and relative abundance of sessile invertebrates, large motile invertebrates and macrophytes. Species enumeration and substrate type are recorded for each contact point. Additionally, four 0.125 m^2 (1.35-ft^2) quadrants are randomly placed within the sampling area to evaluate the distribution and abundance of small, clumped, or patchily distributed organisms. General observations to be recorded during sampling include: quantity and composition of drift algae, conspicuous or sparsely distributed biota not sampled with the point contact method, and substrate alteration (e.g., increased sedimentation). Selected species which are enumerated will be measured, and their general condition recorded. Procurement of some of the physical data, such as temperature and turbidity, will be coordinated with the benthic sampling program.

6.2.1.5 Intertidal organisms

Although not a required component of the preoperational monitoring program, quarterly observations were made along cobble intertidal transects at four monitoring stations and one control station. Predominant macroscopic species and substrate composition were identified and enumerated within three permanent 0.25-m^2 (2.69-ft^2) quadrats along a line perpendicular to the beach. Photographs were also taken of each quadrat for a permanent record of any possible ecological changes.

The staff believes that it is unnecessary to begin the intertidal sampling program until the time of removal of the construction apron from SONGS 2 and 3 (See FES-CP, Sect. 4.3.2, p. 4-9). At that time the intertidal monitoring program should be reinstated to assess the effect of the added sand movement in the intertidal zone. Provided the data show no significant effects, this program may be terminated after all translocation of sand has occurred or after two years. Until the time of apron removal, visual inspection of the intertidal zone will be sufficient, with biological sampling and laboratory analysis initiated only if needed. Deletion of the intertidal program may be reasonable during operational monitoring because of the extensive impact sustained by the intertidal area from activities unassociated with SONGS (Sect. 2.5.2.4) and because of the unlikely potential for any significant impact resulting from SONGS operation.

6.2.1.6 Kelp beds

The three kelp beds, San Mateo, San Onofre, and Barn, located near SONGS (Fig. 6.1) are being studied. A brief outline of the scope of effort at the three kelp beds is as follows:

1. Three benthic stations are located in and about the San Onofre kelp bed and one each at Barn kelp and San Mateo kelp. Stations are quantitatively assessed quarterly.

2. Kelp canopies and rock substrate are mapped for areal extent on a quarterly basis.

3. Water nutrient analysis for ammonia, nitrates, nitrites, and phosphate are taken monthly at all three beds. Water samples are taken from the surface and bottom from within each bed and offshore of each bed. An additional offshore station serves as a monitoring area for upwelling.

4. Kelp tissue analysis for nutrient content is conducted on a monthly basis at all three kelp beds. Each leaf is analyzed for nitrogen content.

5. An assessment of the health of the kelp plants in the three beds is made on a quarterly basis. Parameters assessed include: success of juvenile recruitment, density of kelp plants, amount of encrusting organisms and grazing by herbivores and abundance of senile and diseased plants.

6. Aerial infra-red photographs of the three kelp bed canopies will be taken on a monthly basis.

6.2.2 Water quality monitoring program

The preoperational water quality monitoring program is an expansion of the existing program required by the Environmental Technical Specifications for SONGS 1. This program is designed to establish baseline characteristics of selected oceanographic parameters for comparison with data obtained during the operation of SONGS. This comparison will allow determination of the extent to which SONGS operation alters water quality. Those parameters identified in the FES-CP and in this document which might be altered include: pH, temperature, turbidity, certain heavy metals, and dissolved oxygen.

Sea water temperature-depth profiles are measured bimonthly at stations in the area of the Units 2 and 3 diffusers and at a reference station outside of the area of predicted thermal influence. Stations are as follows: two within each of zones 1B, 2B, 1C, OC, 2C, and 6, six stations within zone OB (Fig. 6.1). Additionally, sea water temperatures are continuously monitored near the surface, at mid-depth, and near the bottom at a permanent station in zone OB. Temperatures from each depth are recorded hourly. The accuracy of the system is ±0.5 degrees centigrade, ±30 minutes per month.

Turbidity is monitored bimonthly at two stations within each of zones 1B, 2B, 1C, OC, 2C, and 6, and at six stations within zone OB (Fig. 6.1). The pH is monitored bimonthly at four sampling stations — one in each of zones OB, 1B, 2B, and 6. Dissolved oxygen is measured bimonthly at four stations — one in each of zones OB, 1B, 2B, and 6.

Mid-depth ocean water samples and grab samples of ocean bottom sediments are collected quarterly in the area of the Units 2 and 3 diffusers and an appropriate control area for analysis of heavy metals. One station in each of zones 1B, 2B, OB, and 6 is sampled. Samples will be analyzed for chromium, iron, and titanium. Copper will not be monitored as the applicant has indicated that SONGS 2 and 3 will have titanium condenser tubing.

The staff considers this program adequate with the following additions: (1) the water quality data should be collected within a two-day period at maximum to permit station-by-station comparisons and the investigation of possible cause and effect relationships, and (2) all control samples should be collected from an area predicted to be unaffected by any discharge effect.

6.2.3 Terrestrial monitoring program

The baseline terrestrial environmental monitoring program for the FES-CP was very nominal. As a condition of the construction permit, the applicant expanded its terrestrial monitoring program to establish an adequate preoperational baseline by which the operational effects of SONGS 2 and 3 may be judged. Biological data were collected seasonally in order to document changes in the biotic communities over a one-year time span. Methods utilized included

small mammal trapping; bird censusing; observations of reptiles, amphibians, and large mammals; plant species lists; and vegetation analyses using the line intercept and quadrat methods. Results of this expanded monitoring program are presented in Sect. 2.5.1.

The applicant has proposed and is currently monitoring areas of cut and fill associated with construction of the plant and transmission lines to detect areas of erosion (ER, Appendix 6A, Special Studies I). Visual inspections are conducted and documented biweekly; any erosion resulting from the applicant's construction activities will receive appropriate corrective action.

6.2.4 Radiological monitoring program

Radiological environmental monitoring programs are established to provide data on measurable levels of radiation and radioactive materials in the site environs. Appendix I to 10 CFR Part 50 requires that the relationship between quantities of radioactive material released in effluents during normal operation, including anticipated operational occurrences, and resultant radioactive doses to individuals from principal pathways of exposure be evaluated. Monitoring programs are conducted to verify the effectiveness of in-plant controls used for reducing the release of radioactive materials and to provide public reassurance that undetected radioactivity will not build up in the environment. A surveillance program is established to identify changes in the use of unrestricted areas to provide a basis for modifications of the monitoring programs.

The preoperational phase of the monitoring program provides for the measurement of background levels and their variations along the anticipated important pathways in the area surrounding the plant; the training of personnel; and the evaluation of procedures, equipment, and techniques.

This is discussed in greater detail in NRC Regulatory Guide 4.1, Rev. 1, "Programs for Monitoring Radioactivity in the Environs of Nuclear Power Plants," and the Radiological Assessment Branch Technical Position, August 1977, "Standard Technical Specification for Radiological Environmental Monitoring Program."

The applicant has proposed a radiological environmental monitoring program to meet the objectives discussed above. The applicant's proposed preoperational radiological environmental monitoring program is presented in Sect. 6.1.5 of the applicant's Environmental Report.

The applicant proposes to initiate parts of the program two years prior to operation of the facility, with the remaining portions beginning either six months or one year prior to operation.

The staff concludes that the radiological preoperational monitoring program proposed by the applicant is acceptable.

6.2.5 Onsite meteorological monitoring program[1,2,3]

The original onsite meteorological program began in late 1964 with wind measurements at the top of a 19.5-m (64-ft) mast. In December 1970, the current meteorological monitoring program began with the installation of a 36.6-m (120-ft) tower atop the coastal bluff about 100 m (330 ft) west-northwest from the Unit 1 containment and 420 m (1380 ft) west-northwest of the Unit 2 containment. In October 1975 the tower was extended to a height of about 43 m (140 ft). Table 6.1 describes the kinds of measurements and their elevations on the tower between 1970 and the present.

Southern California Edison Company also conducted an onshore tracer test program at the San Onofre site. Among the objectives of the program were (1) to evaluate the appropriateness of using data measured on the existing site meteorological tower located on the coastal bluff for making dispersion estimates for onshore flows, and (2) to characterize dispersion representative of meteorological conditions during routine plant releases. NUS-1927[3] describes the test program and data.

On the basis of our analysis of the test data, we conclude that the wind and vertical temperature data measured on the San Onofre onsite (bluff) tower are acceptable for use in calculating atmospheric dispersion estimates for the site vicinity using the staff's model, described in Sect. 2.4.4.

Table 6.1. SONGS onsite meteorological instrumentation

Period	Measured parameter	Elevation above ground	
		Meters	Feet
December 1970–January 1973	Wind direction, speed and standard deviation	36.6	120
	Dry bulb vertical temperature gradient	36.6–6.1	120–20
January 1973–October 1975	Wind direction and speed	10, 36.6	33, 120
	Wind direction standard deviation	36.6	120
	Dry bulb temperature[a]	6.1	20
	Wet bulb temperature[b]	6.1	20
	Dry bulb vertical gradient	36.6–6.1	120–20
October 1975–present	Wind direction and speed	10, 20,[c] 40	33, 66, 131
	Wind direction standard deviation	10	33
	Dry bulb temperature	10	33,
	Dry bulb vertical gradient	40–10[d]	131–33
		36.6–6.1[c]	120–20

[a] Installed January 1974.
[b] Installed January 1974, removed January 1975.
[c] Temporary.
[d] Two sets of instruments.

6.3 OPERATIONAL MONITORING PROGRAMS

6.3.1 Aquatic biological monitoring program

The aquatic biological operational monitoring program will contain sampling programs which are extensions of the baseline and preoperational programs so that analyses can readily be made of the changes, if any, that occur in the aquatic environment due to plant operation. Thus, the ichthyoplankton study now being conducted and the required kelp preoperational program should be continued during operation of the facility until such time as it is possible to state credibly that no significant impacts result from the facility.

The new fish return system (Sect. 3.2.2) is expected to be about 90% effective according to laboratory models (ER, p. 5.1-20). Precise figures on its effectiveness will not be available until it is operated in conjunction with the heat dissipation system. The staff recommends that the applicant include a program for optimizing the effectiveness of the fish return system. This should include consideration of the delayed mortality of the fish successfully diverted by the fish return system by holding them for 48 to 96 hours before returning them to the ocean.

Consideration of deletion of the intertidal sampling program from the operational monitoring program for SONGS 2 and 3 is discussed in Sect. 6.2.1.5.

6.3.2 Water quality monitoring program

The water quality operational monitoring program is a continuation of the existing preoperational water quality monitoring program (Sect. 6.2.2). This continuity will allow for confirmatory monitoring to assess any possible changes to water quality due to operation of San Onofre Units 2 and 3.

The NRC and the California Regional Water Quality Control Board, San Diego Region (CRWQCB) have worked in a cooperative manner in order to develop the preoperational monitoring program for SONGS 2 and 3. NRC and CRWQCB have agreed to continue to work together to establish an operational phase NPDES permit which will incorporate the aquatic concerns from each regulatory group.

6.3.3 Terrestrial monitoring program

The applicant does not have an operational terrestrial monitoring program. The staff does not recommend any operational monitoring of floral or faunal species because no significant

effects have been identified between the operation of SONGS 2 & 3 and the terrestrial environment. The California Coastal Commission, however, requires the applicant to protect the bluffs 0.5 km (0.31 mile) south of the plant site for the duration of the site easement (expiration date, May 1, 2023) (ER, Appendix 12B).

6.3.4 Radiological monitoring program

The operational offsite radiological monitoring program is conducted to measure radiation levels and radioactivity in the plant environs. It assists and provides backup support to the detailed effluent monitoring (as recommended in NRC Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Release of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water Cooled Nuclear Power Plants") which is needed to evaluate individual and population exposures and to verify projected or anticipated radioactivity concentrations.

The applicant plans essentially to continued the proposed preoperational program during the operating period. However, refinements may be made in the program to reflect changes in land use or preoperational monitoring experience.

6.3.5 Meteorological monitoring program

The applicant plans to continue the program begun for the construction permit evaluation. The onsite meteorological tower provides data in accordance with the recommendations of Regulatory Guide 1.23, "Onsite Meteorological Programs." Furthermore, operating technical specifications require meteorological monitoring as a condition of operation.

6.4 RELATED ENVIRONMENTAL RESOURCE DATA

6.4.1 Thermal exception studies

As a condition of the exception to the State Thermal Plan granted by the California Regional Water Quality Control Board, San Diego, the applicants are required to perform studies to determine the optimum mode of heat treatment to control fouling organisms while minimizing adverse effects on marine life and to permit the Regional Board to set precise limits on the frequency, degree, and duration of heat treatment. These studies were submitted to the State Water Resources Control Board on January 31, 1979. On December 18, 1980, the Board determined that the studies fulfilled the conditions set earlier and further determined that the heat treatment operating conditions proposed by the applicant will assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife within the meaning of Section 316(a) of the Clean Water Act.

6.4.2 Marine Review Committee studies

The California Coastal Commission specified in the Coastal Zone Permit issued in 1974 for SONGS 2 and 3 that an extensive study be conducted at San Onofre. The study program is funded by the utility and is being administered by a three-member Marine Review Committee (MRC) appointed by the Coastal Commission. The intent of the program is to provide an independent assessment of the marine environment and a prediction of the potential impact of SONGS 2 and 3. The MRC has identified the following areas for study: physical, oceanographic, and ecological monitoring and modeling; plankton – far field effects and entrainment; fish populations, impingement, and diversion; and benthic communities, intertidal zone organisms, and kelp beds.

MRC has conducted studies at SONGS 2 and 3 in some of the above mentioned areas since August 1976. In November 1980 the MRC issued a report containing its recommendations, predictions, and rationale. The conclusions of the MRC are essentially consistent with those of the staff as described in Section 5 of this statement. Although noting uncertainties, the MRC has concluded that it does not predict at this time that substantial adverse effects on the marine environment are likely to occur from the operations of the SONGS cooling system. Accordingly, the report recommends no design changes but does recommend continued monitoring of the aquatic community to ensure that there is no serious ecological damage, especially to the kelp beds, as a result of plant operation. (See Appendix E for the options and recommendations of the Marine Review Committee.)

6.5 CONCLUSIONS

The preoperational and operational monitoring programs as described above give adequate attention to impacts discussed in this environmental impact statement.

REFERENCES

These documents are available for inspection and copying for a fee in the NRC Public Document room 1717 H Street, N.W., Washington, D.C. 20555

1. Southern California Edison Company, "San Onofre Nuclear Generating Station Units 2 and 3, Environmental Report – Operating License Stage," Docket No. 50-361/362, 1977.

2. Southern California Edison Company, "San Onofre Generating Station Units 2 and 3, Final Safety Analysis Report," Docket No. 50-361/362, 1977.

3. M. Septoff, A. E. Mitchell, and L. H. Teuscher, "Final Report of the Onshore Tracer Tests Conducted December 1976 through March 1977 at the San Onofre Nuclear Generating Station," Report NUS-1927, NUS Corporation, Rockville, Md., 1977.

7. ENVIRONMENTAL IMPACT OF POSTULATED ACCIDENTS

7.1 PLANT ACCIDENTS

The staff has considered the potential radiological impacts on the environment of possible accidents at the San Onofre Nuclear Generating Station Units 2 and 3 in accordance with a Statement of Interim Policy published by the Nuclear Regulatory Commission on June 13, 1980.[1] The following discussion reflects these considerations and conclusions.

The first section deals with general characteristics of nuclear power plant accidents including a brief summary of safety measures to minimize the probability of their occurrence and to mitigate their consequences if they should occur. Also described are the important properties of radioactive materials and the pathways by which they could be transported to become environmental hazards. Potential adverse health effects and impacts on society associated with actions to avoid such health effects are also identified.

Next, actual experience with nuclear power plant accidents and their observed health effects and other societal impacts are then described. This is followed by a summary review of safety features of the San Onofre Units 2 and 3 facilities and of the site that act to mitigate the consequences of accidents.

The results of calculations of the potential consequences of accidents that have been postulated in the design basis are then given. Also described are the results of calculations for the San Onofre site using probabilistic methods to estimate the possible impacts and the risks associated with severe accident sequences of exceedingly low probability of occurrence.

7.1.1 General characteristics of accidents

The term accident, as used in this section, refers to any unintentional event not addressed in Section 5.5 that results in a release of radioactive materials into the environment. The predominant focus, therefore, is on events that can lead to releases substantially in excess of permissible limits for normal operation. Such limits are specified in the Commission's regulations at 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

There are several features which combine to reduce the risk associated with accidents at nuclear power plants. Safety features in the design, construction, and operation comprising the first line of defense are to a very large extent devoted to the prevention of the release of these radioactive materials from their normal places of confinement within the plant. There are also a number of additional lines of defenses that are designed to mitigate the consequences of failures in the first line. Descriptions of these features for the San Onofre Units 2 and 3 plant may be found in the applicant's Final Safety Analysis Report,[2] and in the staff's Safety Evaluation Report.[3] The most important mitigative features are described in Section 7.1.3.1 below.

These safety features are designed taking into consideration the specific locations of radioactive materials within the plant, their amounts, their nuclear, physical, and chemical properties, and their relative tendency to be transported into and for creating biological hazards in the environment.

7.1.1.1 Fission product characteristics

By far the largest inventory of radioactive material in a nuclear power plant is produced as a byproduct of the fission process and is located in the uranium oxide fuel pellets in the form of fission products. These pellets are contained in the fuel rods which make up the fuel assemblies. During periodic refueling shutdowns, the assemblies containing these fuel pellets are transferred to a spent fuel storage pool so that the second largest inventory of radioactive material is located in this storage area. Much smaller inventories of radioactive materials are also normally present in the water that circulates in the primary coolant system and in the systems used to process gaseous and liquid radioactive wastes in the plant.

These radioactive materials exist in a variety of physical and chemical forms. Their potential for dispersion into the environment is dependent not only on mechanical forces that might physically transport them, but also upon their inherent properties, particularly their volatility. The majority of these materials exist as nonvolatile solids over a wide range of temperatures. Some, however, are relatively volatile solids and a few are gaseous in nature. These characteristics have a significant bearing upon the assessment of the environmental radiological impact of accidents.

The gaseous materials include radioactive forms of the chemcially inert noble gases krypton and xenon. These have the highest potential for release into the atmosphere. If a reactor accident were to occur involving degradation of the fuel cladding, the release of substantial quantities of these radioactive gases from the fuel is a virtual certainty. Such accidents are very low frequency but credible events (see Section 7.1.2). It is for this reason that the safety analysis of each nuclear power plant analyzes a hypothetical design basis accident that postulates the release of the entire contained inventory of radioactive noble gases from the fuel into the containment structure. If further released to the environment as a possible result of failure of safety features, the hazard to individuals from these noble gases would arise predominantly through the external gamma radiation from the airborne plume. The reactor containment structure is designed to minimize this type of release.

Radioactive forms of iodine are formed in substantial quantities in the fuel by the fission process and in some chemical forms may be quite volatile. For this reason, they have traditionally been regarded as having a relatively high potential for release from the fuel. The chemical forms in which the fission product radioiodines are found are generally solid materials at room temperature, however, so that they have a strong tendency to condense (or "plate out") upon cooler surfaces. In addition, most of the iodine compounds are quite soluble in, or chemically reactive with, water. Although these properties do not inhibit the release of radioiodines from degraded fuel, they do act to mitigate the release from containment structures that have large internal surface areas and that contain large quantities of water as a result of an accident. The same properties affect the behavior of radioiodines that may "escape" into the atmosphere. Thus, if rainfall occurs during a release, or if there is moisture on exposed surfaces, e.g., dew, the radioiodines will show a strong tendency to be absorbed by the moisture. Because of radioiodine's relatively high solubility and distinct radiological hazard, its potential for release to the atmosphere has also been reduced by the use of special containment spray systems. If released to the environment, the principal radiological hazard associated with the radioiodines is ingestion into the human body and subsequent concentration in the thyroid gland.

Other radioactive materials formed during the operation of a nuclear power plant have lower volatilities and therefore, by comparison with the noble gases and iodine, a much smaller tendency to escape from degraded fuel unless the temperature of the fuel becomes quite high. By the same token, such materials, if they escape by volatilization from the fuel, tend to condense quite rapidly to solid form again when transported to a lower temperature region and/or dissolve in water when present. The former mechanism can have the result of producing some solid particles of sufficiently small size to be carried some distance by a moving stream of gas or air. If such particulate materials are dispersed into the atmosphere as a result of failure of the containment barrier, they will tend to be carried downwind and deposit on surface features by gravitational settling or by precipitation (fallout), where they will become "contamination" hazards in the environment.

All of these radioactive materials exhibit the property of radioactive decay with characteristic half-lives ranging from fractions of a second to many days or years (see Table 7.1). Many of them decay through a sequence or chain of decay processes and all eventually become stable (nonradioactive) materials. The radiation emitted during these decay processes is the reason that they are hazardous materials.

7.1.1.2 Exposure pathways

The radiation exposure (hazard) to individuals is determined by their proximity to the radioactive material, the duration of exposure, and factors that act to shield the individual from the radiation. Pathways for the transport of radiation and radioactive materials that lead to radiation exposure hazards to humans are generally the same for accidental as for "normal" releases. These are depicted in Section 5, Figure 5.17. There are two additional possible pathways that could be significant for accident releases that are not shown in Figure 5.17. One of these is the fallout onto open bodies of water of radioactivity initially carried in the air. The second would be unique to an accident that results in temperatures inside the reactor core sufficiently high to cause melting and subsequent penetration of the basemat underlying the reactor by the molten core debris. This creates the potential for the release of radioactive material into the hydrosphere through contact with ground water. These pathways may lead to external exposure to radiation, and to internal exposures if radioactivity is inhaled, or ingested from contaminated food or water.

Table 7.1 Activity of Radionuclides in a San Onofre Reactor Core at 3560 MWt

Group/Radionuclide	Radioactive Inventory (millions of curies)	Half-life (days)
A. NOBLE GASES		
Krypton-85	0.63	3,950
Krypton-85m	27	0.183
Krypton-87	52	0.0528
Krypton-88	76	0.117
Xenon-133	190	5.28
Xenon-135	38	0.384
B. IODINES		
Iodine-131	95	8.05
Iodine-132	130	0.0958
Iodine-133	190	0.875
Iodine-134	210	0.0366
Iodine-135	170	0.280
C. ALKALI METALS		
Rubidium-86	0.029	18.7
Cesium-134	8.3	750
Cesium-136	3.3	13.0
Cesium-137	5.2	11,000
D. TELLURIUM-ANTIMONY		
Tellurium-127	0.029	18.7
Tellurium-127m	1.2	109
Tellurium-129	34	0.048
Tellurium-129m	5.9	34.0
Tellurium-131m	14	1.25
Tellurium-132	130	3.25
Antimony-127	6.8	3.88
Antimony-129	37	0.179
E. AKALINE EARTHS		
Strontium-89	100	52.1
Strontium-90	4.1	11,030
Strontium-91	120	0.403
Barium-140	180	12.8
F. COBALT AND NOBLE METALS		
Cobalt-58	0.87	71.0
Cobalt-60	0.32	1,920
Molybdenum-99	180	2.8
Technetium-99m	160	0.25
Ruthenium-103	120	39.5
Ruthenium-105	80	0.185
Ruthenium-106	28	366
Rhodium-105	55	1.50
G. RARE EARTHS, REFRACTORY OXIDES AND TRANSURANICS		
Yttrium-99	4.3	2.67
Yttrium-91	130	59.0
Zirconium-95	170	65.2
Zirconium-97	170	0.71
Niobium-95	170	35.0
Lanthanum-140	180	1.67
Cerium-141	170	32.3
Cerium-143	150	1.38
Cerium-144	95	284

Table 7.1 (Continued)

Group/Radionuclide	Radioactive Inventory (millions of curies)	Half-life (days)
G. RARE EARTHS, REFRACTORY OXIDES AND TRANSURANICS (Continued)		
Praseodymium-143	150	13.7
Neodymium-147	67	11.1
Neptunium-239	1800	2.35
Plutonium-238	0.063	32,500
Plutonium-239	0.023	8.9×10^6
Plutonium-240	0.023	2.4×10^6
Plutonium-241	3.8	5,350
Americium-241	0.0019	1.5×10^5
Curium-242	0.56	163
Curium-244	0.026	6,630

NOTE: The above grouping of radionuclides corresponds to that in Table 7.3.

It is characteristic of these pathways that during the transport of radioactive material by wind or by water, the material tends to spread and disperse, like a plume of smoke from a smokestack, becoming less concentrated in larger volumes of air or water. The result of these natural processes is to lessen the intensity of exposure to individuals downwind or downstream of the point of release, but they also tend to increase the number who may be exposed. For a release into the atmosphere, the degree to which dispersion reduces the concentration in the plume at any downwind point is governed by the turbulence characteristics of the atmosphere which vary considerably with time and from place to place. This fact, taken in conjunction with the variability of wind direction and the presence or absence of precipitation, means that accident consequences are very much dependent upon the weather conditions existing at the time.

7.1.1.3 Health effects

The cause and effect relationships between radiation exposure and adverse health effects are quite complex[4] but they have been more exhaustively studied than any other environmental contaminant.

Whole-body radiation exposure resulting in a dose greater than about 10 rem for a few persons and about 25 rem for nearly all people over a short period of time (hours) is necessary before any physiological effects to an individual are clinically detectable. Doses about to 10 to 20 times larger than the latter dose, also received over a relatively short period of time (hours to a few days), can be expected to cause some fatal injuries. At the severe, but extremely low probability end of the accident spectrum, exposures of these magnitudes are theoretically possible for persons in the close proximity of such accidents if measures are not or cannot be taken to provide protection, e.g., by sheltering or evacuation.

Lower levels of exposures may also constitute a health risk, but the ability to define a direct cause and effect relationship between any given health effect and a known exposure to radiation is difficult given the backdrop of the many other possible reasons why a particular effect is observed in a specific individual. For this reason, it is necessary to assess such effects on a statistical basis. Such effects include cancer and genetic changes in future generations after exposure of a prospective parent. Cancer in the exposed population may begin to develop only after a lapse of 2 to 15 years (latent period) from the time of exposure and then continue over a period of about 30 years (plateau period). However, in the case of exposure of fetuses (in utero), cancer may begin to develop at birth (no latent period) and end at age 10 (i.e., the plateau period is 10 years). The health consequences model currently being used is based on the 1972 BEIR Report of the National Academy of Sciences.[5]

Most authorities are in agreement that a reasonable and probably conservative estimate of the statistical relationship between low levels of radiation exposure to a large number of people is within the range of about 10 to 500 potential cancer deaths (although zero

is not excluded by the data) per million man-rem. The range comes from the latest NAS BEIR III Report (1980)[6] which also indicates a probable value of about 150. This value is virtually identical to the value of about 140 used in the current NRC health effects models. In addition, approximately 220 genetic changes per million person-rem would be projected by BEIR III over succeeding generations. That also compares well with the value of about 260 per million man-rem currently used by the NRC staff.

7.1.1.4 Health effects avoidance

Radiation hazards in the environment tend to disappear by the natural process of radioactive decay. Where the decay process is a slow one, however, and where the material becomes relatively fixed in its location as an environmental contaminant (e.g., in soil), the hazard can continue to exist for a relatively long period of time--months, years, or even decades. Thus, a possible consequential environmental societal impact of severe accidents is the avoidance of the health hazard rather than the health hazard itself, by restrictions on the use of the contaminated property or contaminated foodstuffs, milk, and drinking water. The potential economic impacts that this can cause are discussed below.

7.1.2 Accident experience and observed impacts

The evidence of accident frequency and impacts in the past is a useful indicator of future probabilities and impacts. As of mid-1980, there were 69 commercial nuclear power reactor units licensed for operation in the United States at 48 sites with power generating capacities ranging from 50 to 1130 megawatts electric (MWe). (The San Onofre Units 2 and 3 are designed for 1140 MWe each.) The combined experience with these units represents approximately 500 reactor years of operation over an elapsed time of about 20 years. Accidents have occurred at several of these facilities.[7] Some of these have resulted in releases of radioactive material to the environment, ranging from very small fractions of a curie to a few million curies. None is known to have caused any radiation injury or fatality to any member of the public, nor any significant individual or collective public radiation exposure, nor any significant contamination of the environment. This experience base is not large enough to permit a reliable quantitative statistical inference. It does, however, suggest that significant environmental impacts due to accidents are very unlikely to occur over time periods of a few decades.

Melting or severe degradation of reactor fuel has occurred in only one of these 69 operating units, during the accident at Three Mile Island - Unit 2 (TMI-2) on March 28, 1979. In addition to the release of a few million curies of xenon-133, it has been estimated that approximately 15 curies of radioiodine was also released to the environment at TMI-2.[8] This amount represents an extremely minute fraction of the total radioiodine inventory present in the reactor at the time of the accident. No other radioactive fission products were released in measurable quantity.

It has been estimated that the maximum cumulative offsite radiation dose to an individual was less than 100 millirem.[8,9] The total population exposure has been estimated to be in the range from about 1000 to 3000 man-rem. This exposure could produce between none and one additional fatal cancer over the lifetime of the population. The same population receives each year from natural background radiation about 240,000 man-rem and approximately a half-million cancers are expected to develop in this group over its lifetime,[8,9] primarily from causes other than radiation. Trace quantities (barely above the limit of detectability) of radioiodine were found in a few samples of milk produced in the area. No other food or water supplies were impacted.

Accidents at nuclear power plants have also caused occupational injuries and a few fatalities but none attributed to radiation exposure. Individual worker exposures have ranged up to about 4 rems as a direct consequence of accidents, but the collective worker exposure levels (man-rem) are a small fraction of the exposures experienced during normal routine operations that average about 500 man-rem per reactor year.

Accidents have also occurred at other nuclear reactor facilities in the United States and in other countries.[7] Due to inherent differences in design, construction, operation, and purpose of most of these other facilities, their accident record has only indirect relevance to current nuclear power plants. Melting of reactor fuel occurred in at least seven of these accidents, including the one in 1966 at the Enrico Fermi Atomic Power Plant Unit 1. This was a sodium-cooled fast breeder demonstration reactor designed to generate 61 MWe. The damages were repaired and the reactor reached full power four years following the accident. It operated successfully and completed its mission in 1973. This accident did not release any radioactivity to the environment.

A reactor accident in 1957 at Windscale, England released a significant quantity of radioiodine, approximately 20,000 curies, to the environment. This reactor, which was not operated to generate electricity, used air rather than water to cool the uranium fuel. During a special operation to heat the large amount of graphite in this reactor, the fuel overheated and radioiodine and noble gases were released directly to the atmosphere from a 123-m (405-ft) stack. Milk produced in a 512-km^2 (200-mi^2) area around the facility was impounded for up to 44 days. This kind of accident cannot occur in a reactor like San Onofre, however, because of its water-cooled design.

7.1.3 Mitigation of accident consequences

The Nuclear Regulatory Commission is conducting a safety evaluation of the application to operate San Onofre Units 2 and 3. Although this evaluation will contain more detailed information on plant design, the principal design features are presented in the following section.

7.1.3.1 Design features

San Onofre Units 2 and 3 are essentially identical units. Each contains features designed to prevent accidental release of radioactive fission products from the fuel and to lessen the consequences should such a release occur. Many of the design and operating specifications of these features are derived from the analysis of postulated events known as design basis accidents. These accident preventive and mitigative features are collectively referred to as engineered safety features (ESF). The possibilities or probabilities of failure of these systems are incorporated in the assessments discussed in section 7.1.4.

Each steel-lined concrete containment building is a passive mitigating system which is designed to minimize accidental radioactivity releases to the environment. Safety injection systems are incorporated to provide cooling water to the reactor core during an accident to prevent or minimize fuel damage. The containment atmosphere cooling system provides heat removal capability inside the containment following steam release accidents and helps to prevent containment failure due to overpressure. Similarly, the containment spray system is designed to spray cool water into the containment atmosphere. The spray water also contains an additive (sodium hydroxide) which will chemically react with any airborne radioiodine to remove it from the containment atmosphere and prevent its release to the environment.

The mechanical systems mentioned above are supplied with emergency power from onsite diesel generators in the event that normal offsite station power is interrupted.

The fuel handling area of each unit is located in a fuel building, a low leakage structure with a safety-grade ventilation system for accident mitigation. The safety-grade ventilation system is an internal recirculation system and contains both charcoal and high efficiency particulate filters. If radioactivity were to be released into the building, it would be drawn through the ventilation system, and radioactive iodine and particulate fission products would be removed from the flow stream, reducing the concentration within the building and hence the amount that might leak to the atmosphere.

There are features of each unit that are necessary for its power generation function that can also play a role in mitigating certain accident consequences. For example, the main condenser, although not classified as an ESF, can act to mitigate the consequences of accidents involving leakage from the primary to the secondary side of the steam generators (such as steam generator-tube ruptures).

If normal offsite power is maintained, the ability of the plant to send contaminated steam to the condenser instead of releasing it through the safety valves or atmospheric dump valves can significantly reduce the amount of radioactivity released to the environment. In this case, the fission product removal capability of the normally operating off-gas treatment system would come into play.

Much more extensive discussions of the safety features and characteristics of San Onofre Units 2 and 3 may be found in the applicant's Final Safety Analysis Report.[2] The staff evaluation of these features is addressed in the Safety Evaluation Report. In addition, the implementation of the lessons learned from the TMI-2 accident, in the form of improvements in design and procedures, and operator training, will significantly reduce the likelihood of a degraded core accident which could result in large releases of fission products to the containment. Specifically, the applicant will be required to meet those TMI-related requirements specified in NUREG-0737. As noted in Section 7.1.4.7, no credit has been taken for these actions and improvements in discussing the radiological risk of accidents in this supplement.

7.1.3.2 Site features

In the process of considering the suitability of the site of San Onofre Units 2 and 3, pursuant to NRC's Reactor Site Criteria in 10 CFR Part 100, consideration was given to certain factors that tend to minimize the risk and the potential impact of accidents. First, the site has an exclusion area as required in 10 CFR Part 100. The exclusion area of the (33.8 hectare (83.6-acre)) site has a minimum exclusion distance of (1968 ft) 600 meters from the containment centerlines to the closest site boundary. The applicant's authority to control all activities within the exclusion area was acquired by a grant of easement from the United States of America made by the Secretary of the Navy. The exclusion area is traversed by old U.S. Highway 101, the San Diego Freeway (Interstate 5), and the Atchison, Topeka and Santa Fe Railroad. The exclusion area on the ocean side extends over a narrow strip of beach and into the Pacific Ocean.

The applicant's control of the landward portion of the exclusion area extends to the mean high tide line but does not include the strip of beach lying between high and low tide that is occasionally uncovered. This strip of "tidal beach" is owned by the State of California and is used primarily as a passageway for individuals walking along the beach. The applicant's lack of control of this strip of tidal beach has been adjudicated in a Commission proceeding (see ALAB-432) and has been determined to be de minimis on the basis of its occasional use, together with the high probability that any radiation exposure to individuals in this zone will be within the guideline values of 10 CFR Part 100 in the event of an emergency.

Activities within the exclusion area which are unrelated to plant operation include a gas pipeline, railroad traffic, through traffic on the San Diego Freeway, and local recreational traffic on old U.S. Highway 101. Recreational activities in the plant vicinity include swimming, camping, and surfing. Recreational activities, such as sunbathing or picnicking, are discouraged within the landward portion of the exclusion area (the area landward of the contour of mean high tide). The seaward portion of the exclusion area (the area seaward of the contour of mean high tide) may be occupied by small numbers of people for passageway transit between the public beach areas upcoast and downcoast from the plant. Additional small numbers of people may be anticipated to occasionally be in the water within the exclusion area.

Transient access to an approximate 2.02-hectare (5-acre) at the southwest corner of the site for the purposes of viewing the scenic bluffs and barrancas will be on an unimproved walkway. The applicant has estimated that at any one time a maximum of 100 persons will be in the walkway and a 2.02-hectare (5-acre) viewing area, and on the beach and water below the mean high tide. The improved walkway affords landward passage between the two beach areas.

In case of a radiological emergency, the applicants have made arrangements with agencies of the State and local governments to control all traffic on the railroad, roadways, and waterways.

Second, beyond and surrounding the exclusion area is a low population zone (LPZ), also required by Part 100. This is a circular area of 3.14 km (1.95 mi) outer radius. Within this zone the applicant must assure that there is reasonable probability that appropriate measures could be taken on behalf of the residents in the event of a serious accident.

The San Onofre State Beach northwest and southwest of the San Onofre exclusion areas represents a public waterfront recreation area within an 8-km (5-mi) radius of the plant. The beach south of the nuclear facility is used for swimming, hiking, and vehicle parking. The 1036 m (3,400-ft) stretch of beach north of the site is used primarily for surfing.

The largest communities in the vicinity of the site are San Clemente, located about 4.8 km (3 mi) away, which had a 1976 estimated population of 23,000, and the U.S. Marine Corp base Camp Pendleton, with a total estimated population of about 33,000. The Marine Corp base consists of several population clusters or camps located at distances from 2.4 km to 19.31 km (1.5 mi to 12 mi) away.

The applicant has estimated a peak transient population in major tourist and recreational activities along Interstate 5 in a 16-km (10-mi) radius of the plant to be 56,600 persons. This occurs during the summer months and is due to persons engaged in water sport recreation on the Pacific Ocean beach and coastal waters.

The Mexican border lies about 121 km (75 mi) from San Onofre, toward the southeast. The cities of Tijuana, Mexicali, and Ensenada are within 241 km (150 mi) of the site.

The safety evaluation of the San Onofre site has also included a review of potential external hazards, i.e., activities offsite that might adversely affect the operation of the plant and cause an accident. This review encompassed nearby industrial, transportation, and military facilities that might create explosive, missile, toxic gas, or similar hazards. The staff concluded at the construction permit stage that the hazards from the nearby military facility are negligibly small. However, the hazards from the nearby interstate highway, the railroad right of way, and natural gas pipelines, are still under review by the staff. Reevaluation of these hazards has been requested by the staff, and the results will be reported in a supplement to the staff's Safety Evaluation Report. It is anticipated that the review will show that either the risks are acceptably small or may be acceptably small.

7.1.3.3 Emergency preparedness

Emergency preparedness plans including protective action measures for the San Onofre facility and environs are in an advanced, but not yet fully completed stage. In accordance with the provisions of 10 CFR Section 50.47, effective November 3, 1980, no operating license will be issued to the applicant unless a finding is made by the NRC that the state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Among the standards that must be met by these plans are provisions for two Emergency Planning Zones (EPZ). A plume exposure pathway EPZ of about 16 km (10 mi) in radius and an ingestion exposure pathway EPZ of about 80 km (50 mi) in radius are required. Other standards include appropriate ranges of protective actions for each of these zones, provisions for dissemination to the public of basic emergency planning information, provisions for rapid notification of the public during a serious reactor emergency, and methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences in the EPZs of a radiological emergency condition.

NRC findings will be based upon a review of the Federal Emergency Management Agency (FEMA) findings and determinations as to whether State and local government emergency plans are adequate and capable of being implemented, and on the NRC assessment as to whether the applicant's onsite plans are adequate and capable of being implemented. NRC staff findings will be reported in a supplement to the staff's Safety Evaluation Report. Although the presence of adequate and tested emergency plans cannot prevent the occurrence of an accident, it is the judgment of the staff that they can and will substantially mitigate the consequences to the public if one should occur.

7.1.4 Accident risk and impact assessment

7.1.4.1 Design basis accidents

As a means of assuring that certain features of the San Onofre Units 2 and 3 plants meet acceptable design and performance criteria, both the applicant and the staff have analyzed the potential consequences of a number of postulated accidents. Some of these could lead to significant releases of radioactive materials to the environment, and calculations have been performed to estimate the potential radiological consequences to persons offsite. For each postulated initiating event, the potential radiological consequences cover a considerable range of values depending upon the particular course taken by the accident and the conditions, including wind direction and weather, prevalent during the accident.

In the safety analysis of the San Onofre Units 2 and 3 plants, three categories of accidents have been considered. These categories are based upon their probability of occurrence and include (a) incidents of moderate frequency, i.e., events that can reasonably be expected to occur during any year of operation, (b) infrequent accidents, i.e., events that might occur once during the lifetime of the plant, and (c) limiting faults, i.e., accidents not expected to occur but that have the potential for significant releases of radioactivity. The radiological consequences of incidents in the first category, also called anticipated operational occurrences, are discussed in Section 5. Initiating events postulated in the second and third categories for the San Onofre Units 2 and 3 are shown in Table 7.2. These are collectively designated design basis accidents in that specific design and operating features as described above in Section 7.1.3.1 are provided to limit their potential radiological consequences. Approximate radiation doses that might be received by a person at the nearest site boundary (600 meters from the plant) are also shown in the table, along with a characterization of the time duration of the releases.

Table 7.2 Approximate Radiation Doses from Design Basis Accidents, Conservative Calculational Model

	Duration of Release	Dose (rem at 600 m[1]) Whole Body	Thyroid
Infrequent Accidents:			
Waste Gas Tank Failure	< 2 hr	< 3	< 30
Steam Generator Tube[2] Rupture	< 2 hr	< 3	2
Fuel Handling Accident	< 2 hr	7	40
Limiting Faults:			
Main Steam Line Break	< 2 hr	6	10
Control Rod Ejection	hrs-days	< 6	60
Large-Break LOCA	hrs-days	3	100

[1]The nearest site boundary.
[2]See NUREG-0651[6] for descriptions of three steam generator tube rupture accidents that have occurred in the United States.

The calculational model used is a conservative one in that it is expected to provide a reasonable estimate of the potential upper bound for individual exposures. The results are used to implement the provisions of 10 CFR 100 and to establish performance requirements for certain engineered safety features. The conservative assumptions used in these analyses include: (1) large (upper bound) amounts of radioactive material released by the initiating event, (2) single failures in important equipment, including operating the engineered safety features in a degraded mode,* (3) very adverse meteorological conditions, and (4) no reduction in exposure due to possible protective actions.

The results of these calculations show that, for these events, the limiting whole-body exposures are not expected to exceed 7 rem. They also show that radioiodine releases have the potential for offsite exposures ranging up to about 100 rem to the thyroid. For such an exposure to occur, an individual would have to be located at a point on the site boundary where the radioiodine concentration in the plume has its highest value and inhale at a breathing rate characteristic of a person jogging, for a period of two hours. The health risk to an individual receiving such a thyroid exposure is the potential appearance of benign or malignant thyroid nodules in about 4 out of 100 cases, and the development of a fatal cancer in about 2 out of 1000 cases.

The realistically expected consequences, were one of these initiating events actually to occur, would be very substantially less. Therefore, the risk is judged to be extremely small for these design basis accidents. The subject of risk is more fully discussed in Section 7.1.4.6 below.

7.1.4.2 Probabilistic assessment of severe accidents

In this and the following three sections, there is a discussion of the probabilities and consequences of accidents of greater severity than the design basis accidents identified in the previous section. As a class, they are considered less likely to occur, but their consequences could be more severe, both for the plant itself and for the environment. These severe accidents, heretofore frequently called Class 9 accidents, can be distinguished from design basis accidents in two primary respects: they involve substantial physical deterioration of the fuel in the reactor core, including overheating to the point of melting, and they involve deterioration of the capability of the containment structure to perform its intended function of limiting the release of radioactive materials to the environment.

*The containment structure, however, is assumed to prevent leakage in excess of that which can be demonstrated by testing, as provided in 10 CFR Section 100.11(a).

The assessment methodology employed is that described in the Reactor Safety Study (RSS) which was published in 1975.[10*] The San Onofre Units 2 and 3 are Combustion Engineering-designed pressurized water reactors (PWR) having similar design and operating characteristics to the Surry Unit 1 facility used in the RSS as a prototype for PWRs. This assessment has used as its starting point, therefore, the same set of accident sequences that were found in the RSS to be dominant contributors to risk in the prototype PWR. The same set of nine release categories, designated PWR 1 through 9, have also been used to represent the spectrum of severe accident releases that are hypothesized for the San Onofre Units 2 and 3. Characteristics of these categories are shown in Table 7.3. Sequences initiated by natural phenomena such as tornadoes, floods, or seismic events and those that could be initiated by deliberate acts of sabotage are not included in these events sequences. The radiological consequences of such events would not be different in kind from those which have been treated. Moreover, it is the staff's judgment, based upon design requirements of 10 CFR Part 50, Appendix A, relating to effects of natural phenomena, and safeguards requirements of 10 CFR Part 73, that these events do not contribute significantly to risk. The facts upon which the staff based its Safe Shutdown Earthquake and its conclusions regarding the effects of natural phenomena on the plant are given in the Safety Evaluation Report.

A calculated probability per reactor year associated with each release category is also shown in the second column in Table 7.3. These probabilities are the result of a detailed engineering analysis of the prototype PWR in the Reactor Safety Study. There are substantial uncertainties in these probabilities. This is due, in part, to difficulties associated with the quantification of human error and to inadequacies in the data base on failure rates of individual plant components that were used to calculate the probabilities[11] (see Section 7.1.4.7 below). Also, the detailed engineering analysis represents a plant designed by a different nuclear steam supply system designer (CE versus Westinghouse) with different detailed designs. The probability of accident sequences from the Surry plant were used to give a perspective of the societal risk at San Onofre Units 2 and 3 because, although the probabilities of particular accident sequences may be substantially different, the overall effect of all sequences taken together is likely to be within the uncertainties. Except as indicated in the footnotes in Table 7.3, the staff has no present basis for judging whether the probabilities may be too high or too low. The error band for the probabilities of some of the event sequences could be as great as a factor of 100. The event sequences in categories PWR 1-7 lead to partial or complete melting of the reactor core while those in the last two categories do not involve melting of the core. In release categories 1 to 3, the event sequences include containment failure by steam explosion, hydrogen burning, or overpressure. In release categories 6 and 7, the dominant containment failure mode is by melt-through of the containment base mat. The other release categories contain event sequences in which the systems intended to isolate the containment fail to act properly.

The magnitudes (curies) of radioactivity releases for each category are obtained by multiplying the release fractions shown in Table 7.3 by the amounts that would be present in the core at the time of the hypothetical accident. These are shown in Table 7.1 for a San Onofre plant at a core thermal power level of 3560 megawatts.

The potential radiological consequences of these releases have been calculated by the consequence model used in the RSS[12] and adapted to apply to a specific site. The essential elements are shown in schematic form in Figure 7.1. Environmental parameters specific to the San Onofre site have been used and include the following:

(1) Meteorological data for the site representing a full year of consecutive hourly measurements and seasonal variations.

(2) Projected population in the United States and Mexico for the year 2000 extending throughout regions of 80 and 560 km (50 and 350 mi) radius from the site.

(3) The habitable land fraction within the 560-km (350-mi) radius.

(4) Land use statistics, on a state-wide basis, including farm land values, farm product values including dairy production, and growing season information, for the State of California and each surrounding State within the 560-km (350-mi) region.

(5) Land use statistics for Mexico on a country-wide basis. Farm land values, growing season information, and comparison between agriculture and dairy products are based on comparison with U.S. values for nearby States. Farm product values are based on Mexico-average Gross National Product and "agriculture" percentage.

*Because this report has been the subject of considerable controversy, a discussion of the uncertainties surrounding it is provided in Section 7.1.4-7.

Table 7.3

Summary of Atmospheric Release Categories Representing Hypothetical Accidents in a PWR

Release Category	Probability (reactor-yr^{-1})	Fraction of Core Inventory Released[a]						
		Xe-Kr	I	Cs-Rb	Te-Sb	Ba-Sr	Ru[b]	La[c]
PWR 1	5.1×10^{-8}[d]	0.9	0.7	0.4	0.4	0.05	0.4	3×10^{-3}
PWR 2	7×10^{-6}	0.9	0.7	0.5	0.3	0.06	0.02	4×10^{-3}
PWR 3	2.3×10^{-6}	0.8	0.2	0.2	0.3	0.02	0.03	3×10^{-3}
PWR 4	2.1×10^{-11}	0.6	0.09	0.04	0.03	5×10^{-3}	3×10^{-3}	4×10^{-4}
PWR 5	5×10^{-8}	0.3	0.03	9×10^{-3}	5×10^{-3}	1×10^{-3}	6×10^{-4}	7×10^{-5}
PWR 6	6×10^{-7}	0.3	3×10^{-3}	8×10^{-4}	1×10^{-3}	9×10^{-5}	7×10^{-5}	1×10^{-5}
PWR 7	4×10^{-5}	6×10^{-3}	4×10^{-5}	1×10^{-5}	2×10^{-5}	1×10^{-6}	1×10^{-6}	2×10^{-7}
PWR 8	4×10^{-5}	2×10^{-3}	1×10^{-4}	5×10^{-4}	1×10^{-6}	1×10^{-8}	0	0
PWR 9	4×10^{-4}	3×10^{-6}	1×10^{-7}	6×10^{-7}	1×10^{-9}	1×10^{-11}	0	0

[a] Background on the isotope groups and release mechanisms is presented in Appendix VII, WASH-1400 (Ref. 9).

[b] Includes Ru, Rh, Co, Mo, Tc.

[c] Includes, Y, La, Zr, Nb, Ce, Pr, Nd, Np, Pu, Am, Cm.

[d] Current understanding of the phenomenon of containment failure by steam explosion embodied in this release category indicates the probability should be lower than stated.

NOTE: Refer to Section 7.1.4.6 for a discussion of uncertainties in risk estimates.

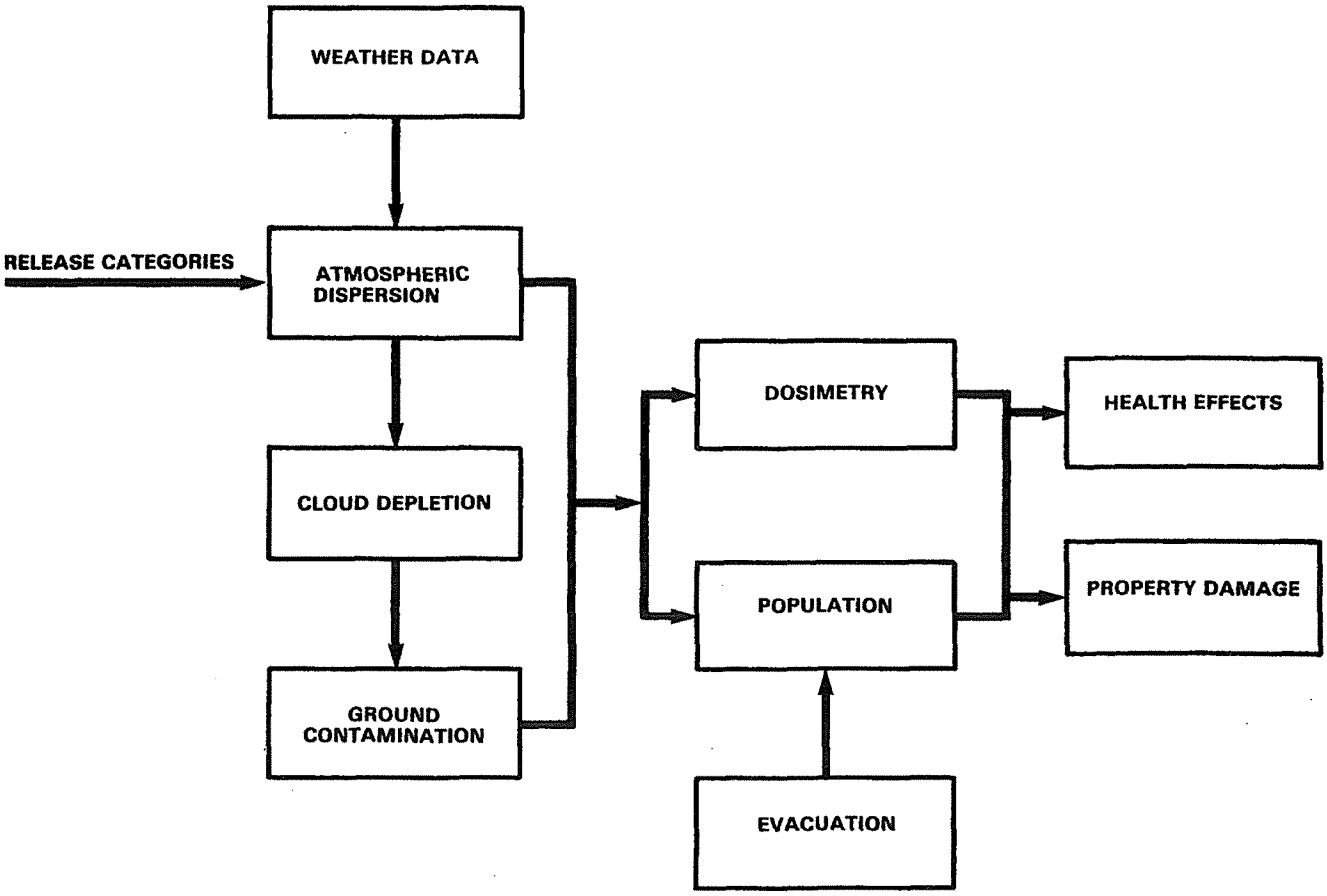

Figure 7.1 Schematic outline of consequence model

To obtain a probability distribution of consequences the calculations are performed assuming the occurrence of each accident release sequence at each of 91 different "start" times throughout a one-year period. Each calculation utilizes the site specific hourly meteorological data and seasonal information for the time period following each "start" time. The consequence model also contains provisions for incorporating the consequence reduction benefits of evacuation and other protective actions. Early evacuation of people would considerably reduce the exposure from the radioactive cloud and the contaminated ground in the wake of the cloud passage. The evacuation model used (see Appendix F) has been revised from that used in the RSS for better site-specific application. The quantitative characteristics of the evacuation model used for the San Onofre site are best estimate values made by the staff and based upon evacuation time estimates prepared by the applicant. Actual evacuation effectiveness could be greater or less than that characterized but would not be expected to be much less, even under adverse conditions.

The other protective actions include: (a) either complete denial of use (interdiction), or permitting use only at a sufficiently later time after appropriate decontamination of food stuffs such as crops and milk, (b) decontamination of severely contaminated environment (land and property) when it is considered to be economically feasible to lower the levels of contamination to protective action guide (PAG) levels, and (c) denial of use (interdiction) of severely contaminated land and property for varying periods of time until the contamination levels reduce to such values by radioactive decay and weathering so that land and property can be economically decontaminated as in (b) above. These actions would reduce the radiological exposure to the people from immediate and/or subsequent use of or living in the contaminated environment.

Early evaucation and other protective actions as mentioned above are considered as essential sequels to serious nuclear reactor accidents involving significant release of radioactivity to the atmosphere. Therefore, the results shown for San Onofre reactor include the benefits of these protective actions.

There are also uncertainties in the estimates of consequences, and the error bounds may be as large as they are for the probabilities. It is the judgment of the staff, however, that it is more likely that the calculated results are overestimates of consequences rather than underestimates.

The results of the calculations using this consequence model are radiological doses to individuals and to populations, health effects that might result from these exposures, costs of implementing protective actions, and costs associated with property damage by radioactive contamination.

7.1.4.3 Dose and health impacts of atmospheric releases

The results of the calculations of dose and health impacts performed for the San Onofre facility and site are presented in the form of probability distributions in Figures 7.2 through 7.5 and are included in the impact Summary Table 7.4. All of the nine release categories shown in Table 7.3 contribute to the results, the consequences from each being weighted by its associated probability.

Figure 7.2 shows the probability distribution for the number of persons who might receive whole body doses equal to or greater than 200 rem and 25 rem, and thyroid doses equal to or greater than 300 rem from early exposure,* all on a per-reactor-year basis. The 200 rem whole body dose figure corresponds approximately to a threshold value for which hospitalization would be indicated for the treatment of radiation injury. The 25 rem whole body (which has been identified earlier as the lower limit for clinically obervable physiological effects in nearly all people) and 300 rem thyroid figures correspond to the Commission's guidelines values for reactor siting in 10 CFR Part 100.

The figure shows in the left-hand portion that there is less than 1 chance in 100,000 per year (i.e. 10^{-5}) that one or more persons may receive doses equal to or greater than any of the doses specified. The fact that the three curves run almost parallel in horizontal lines initially shows that if one person were to receive such doses, the chances are about the same that several tens to hundreds would be so exposed. The chances of larger numbers of persons being exposed at those levels are seen to be considerably smaller. For example, the chances are about 1 in 100,000,000 (i.e. 10^{-8}) that 100,000 or more people might receive doses of 200 rem or greater. A majority of the exposures reflected in this figure would be expected to occur to persons within a 80-km (50-mi) radius of the plant. Virtually all would occur with a 160-km (100-mi) radius.

*The containment structure, however, is assumed to prevent leakage in excess of that which can be demonstrated by testing, as provided in 10 CFR Section 100.11(a).

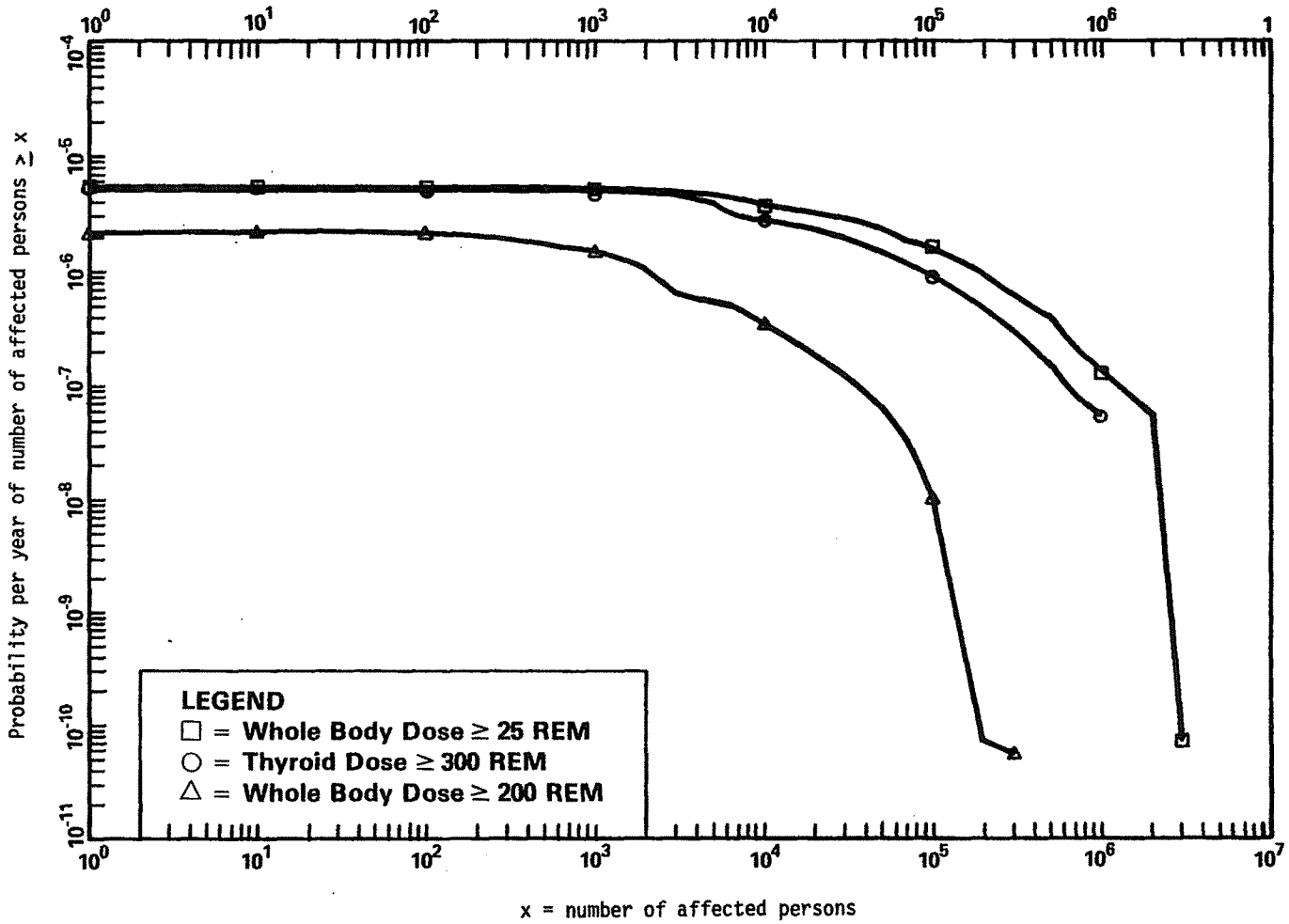

Figure 7.2 Probability distribution of individual dose impacts
(See Section 7.1.4.6 for a discussion of uncertainties in risk estimates.)

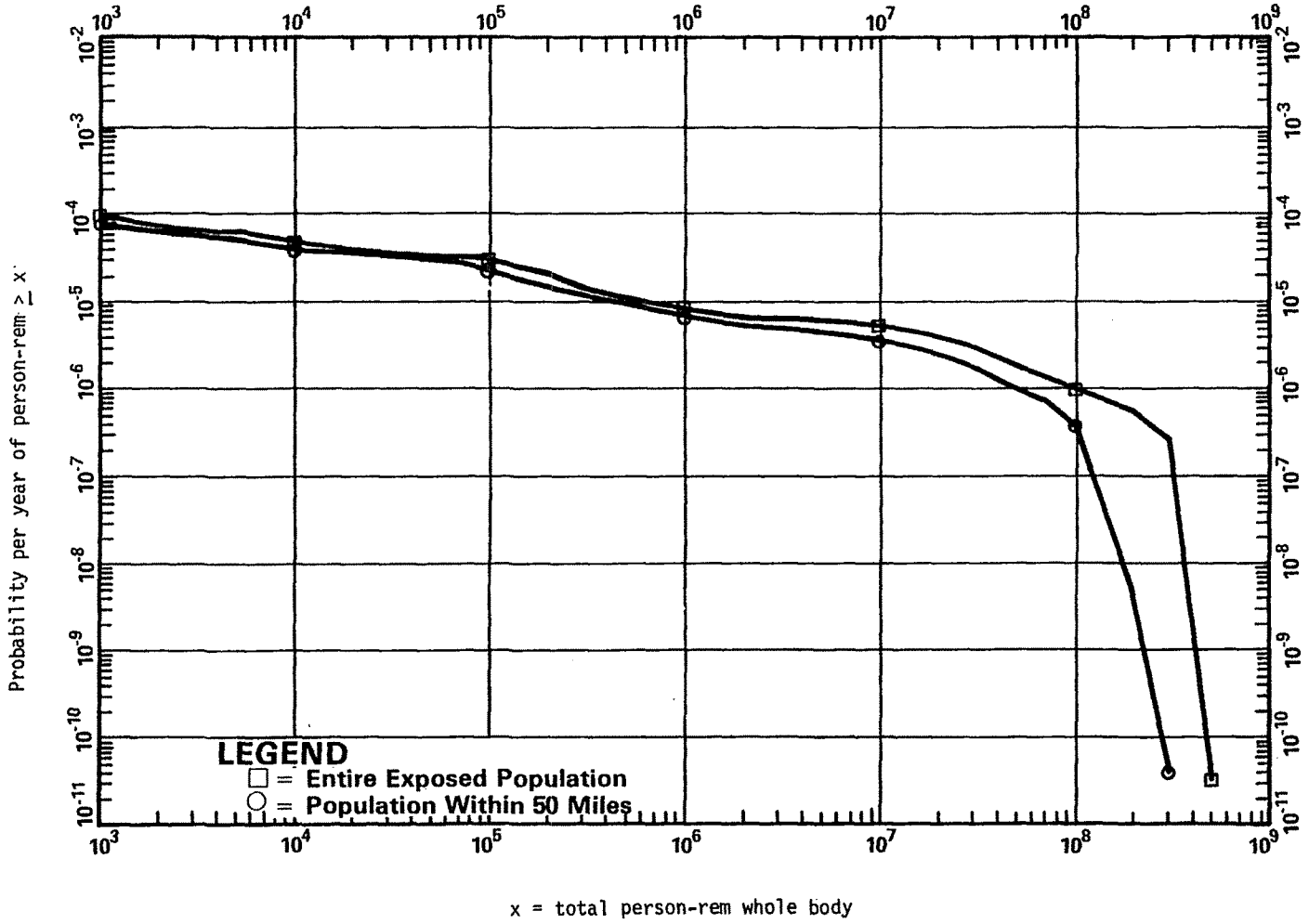

Figure 7.3 Probability distribution of population exposures. (See Section 7.1.4.6 for discussion of uncertainties in risk estimates.) (To convert miles to kilometers, multiply by 1.6.)

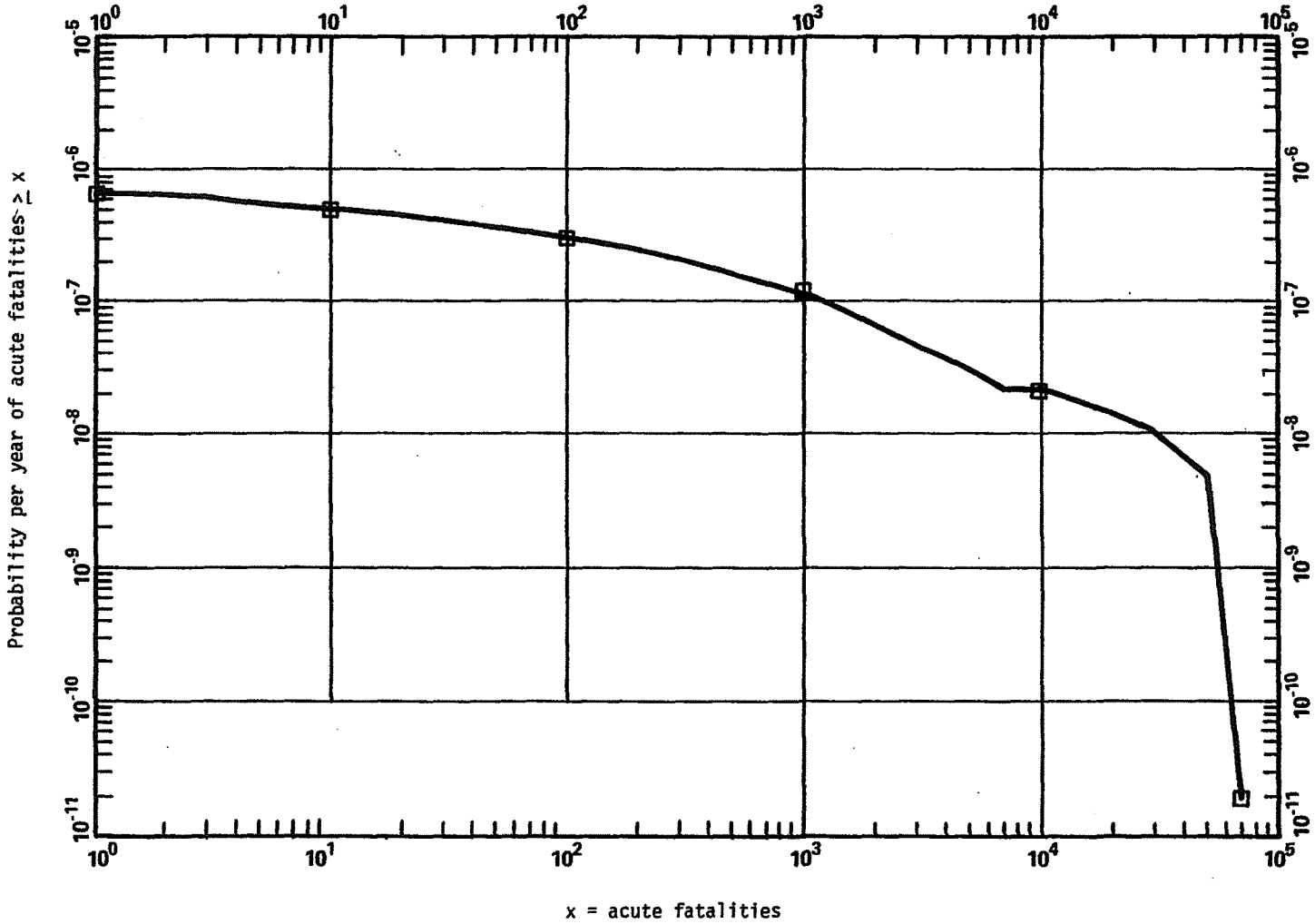

Figure 7.4 Probability distribution of acute fatalities. (See Section 7.1.4.6 for discussion of uncertainties in risk estimates.)

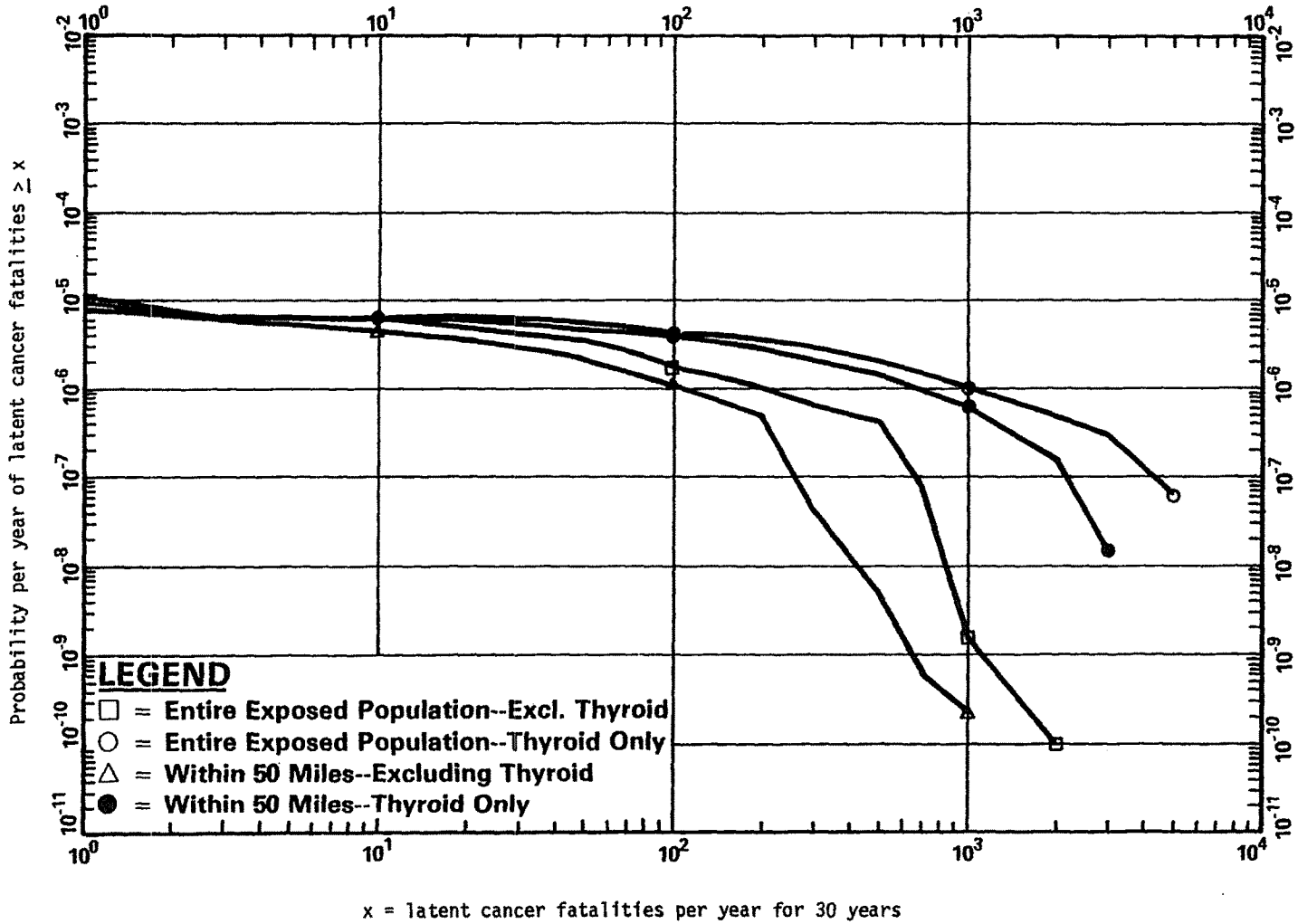

Figure 7.5 Probability distribution of cancer fatalities. (See Section 7.1.4.6 for discussion of uncertainties in risk estimates.) (To convert miles to kilometers, multiply by 1.6.)

Table 7.4 Summary of Environmental Impacts and Probabilities

Probability of impact per year	Persons exposed over 200 rem	Persons exposed over 25 rem	Acute fatalities	Population exposure, millions of man-rem 80 km/total	Latent* cancers, 80 km/total	Cost of offsite mitigating actions, $ millions
10^{-4}	< 1	< 1	< 1	< 0.001	< 60	< 0.001
10^{-5}	< 1	< 1	< 1	0.4/0.6	< 60	12
5×10^{-6}	< 1	160	< 1	2/10	1,400/2,500	400
10^{-6}	2,000	190,000	< 1	45/100	23,000/36,000	5,000
10^{-7}	31,000	1,100,000	1,100	110/300	71,000/143,000	15,000
10^{-8}	100,000	2,000,000	30,000	170/340	12,000/24,000	35,000
Related Figure	7.2	7.2	7.4	7.3	7.5	7.6

*Genetic effects would be approximately twice the number of latent cancers. Thirty times the values shown in the Figure 7.5 are shown in this column reflecting the 30-year period over which they might occur.

NOTE: Refer to Section 7.1.4.6 for a discussion of uncertainties in risk estimates.

Figure 7.3 shows the probability distribution for the total population exposure in person-rem, i.e., the probability per reactor-year that the total population exposure will equal or exceed the values given. A substantial fraction of the population exposure would occur within 80 km (50 mi) but the more severe releases (PWR 1-6) would result in exposure to persons beyond the 80-km (50-mi) range as shown.

For perspective, population doses shown in Figure 7.3 may be compared with the annual average dose to the population within 80 km (50 mi) of the San Onofre site due to natural background radiation of 700,000 man-rem, and to the anticipated annual population dose to the general public from normal station operation of 460 man-rem (excluding plant workers) (Section 5, Table 5.3 and 5.5).

Figure 7.4 shows the probability distribution for acute fatalities, representing radiation injuries that would produce fatalities within about one year after exposure. Virtually all of the acute fatalities would be expected to occur within a 64-km (40-mi) radius. The results of the calculations shown in this figure and in Table 7.4 reflect the effect of evacuation within the 16-km (10-mi) plume exposure pathway EPZ only. For the very low probability accidents having the potential for causing radiation exposure above the threshold for acute fatality at distances beyond 16 km (10 mi), it would be realistic to expect that authorities would evacuate persons at all distances at which such exposures might occur. Acute fatality consequences would therefore reasonably be expected to be very much less than the numbers shown.

Figure 7.5 represents the statistical relationship between population exposure and the induction of fatal cancers that might appear over a period of many years following exposure. The impacts on the total population and the population within 80 km (50 mi) are shown separately. Further, the fatal, latent cancers have been subdivided into those attributable to exposures of the thyroid and all other organs.

7.1.4.4 Economic and societal impacts

As noted in Section 7.1.1, the various measures for avoidance of adverse health effects including those due to residual radioactive contamination in the environment are possible consequential impacts of severe accidents. Calculations of the probabilities and magnitudes of such impacts for the San Onofre facility and environs have also been made. Unlike the radiation exposure and adverse health effect impacts discussed above, impacts associated with adverse health effects avoidance are more readily transformed into economic impacts.

The results are shown as the probability distribution for costs of offsite mitigating actions in Figure 7.6 and are included in the impact Summary Table 7.4. The factors contributing to these estimated costs include the following:

- Evacuation costs
- Value of crops contaminated and condemned
- Value of milk contaminated and condemned
- Costs of decontamination of property where practical
- Indirect costs due to loss of use of property and incomes derived therefrom.

The last named costs would derive from the necessity for interdiction to prevent the use of property until it is either free of contamination or can be economically decontaminated.

Figure 7.6 shows that at the extreme end of the accident spectrum these costs could exceed tens of billions of dollars but that the probability that this would occur is exceedingly small, less than one chance in a hundred million per year.

Additional economic impacts that can be monetized include costs of decontamination of the facility itself and the costs of replacement power. Probability distributions for these impacts have not been calculated, but they are included in the discussion of risk considerations in Section 7.1.4.6 below.

7.1.4.5 Releases to groundwater

A pathway for public radiation exposure and environmental contamination that could be associated with severe reactor accidents was identified in Section 7.1.1.2 above. Consideration has been given to the potential environmental impact of this pathway for the San Onofre plant. The principal contributors to the risk are the core melt accidents associated with the PWR-1 through 7 release categories. The penetration of the basemat of the

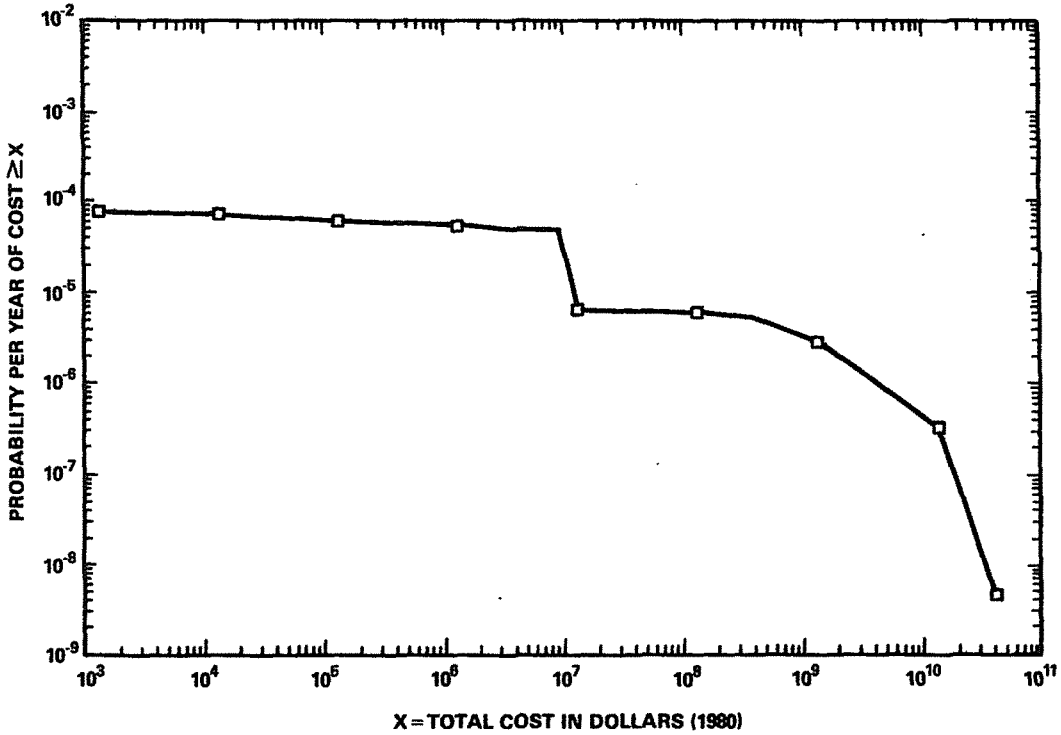

Figure 7.6 Probability distribution of cost of offsite mitigative measures

containment building can release molten core debris to the strata beneath the plant. Soluble radionuclides in this debris can be leached and transported with groundwater to downgradient domestic wells used for drinking or to surface water bodies used for drinking water, aquatic food and recreation. In pressurized water reactors, such as the San Onofre unit, there is an additional opportunity for groundwater contamination due to the release of contaminated sump water to the ground through a breach in the containment.

An analysis of the potential consequences of a liquid pathway release of radioactivity for generic sites was presented in the "Liquid Pathway Generic Study" (LPGS).[13] The LPGS compared the risk of accidents involving the liquid pathway (drinking water, irrigation, aquatic food, swimming and shoreline usage) for four conventional, generic land-based nuclear plants and a floating nuclear plant, for which the nuclear reactors would be mounted on a barge and moored in a water body. Parameters for the land-based sites were chosen to represent averages for a wide range of real sites and are thus "typical," but represented no real site in particular.

The discussion in this section is an analysis to determine whether or not the San Onofre site liquid pathway consequences would be unique when compared to land-based sites considered in the LPGS. The method consists of a direct scaling of the LPGS population doses based on the relative values of key parameters characterizing the LPGS "ocean" site and the San Onofre site. The parameters which were evaluated included amounts of radioactive materials entering the ground, groundwater travel time, sorption on geological media, surface water transport, aquatic food consumption, and shoreline usage.

Doses to individuals and populations were calculated in the LPGS without consideration of interdiction methods such as isolating the contaminated groundwater or denying use of the water. In the event of surface water contamination, commercial and sports fishing, as well as many other water-related activities would be restricted. The consequences would therefore be largely economic or social, rather than radiological. In any event, the individual and population doses for the liquid pathway range from fractions to very small fractions of those that can arise from the airborne pathways.

The San Onofre reactors are situated above the San Mateo Formation, which is about 274-m (876.8-ft) thick and consists of medium to coarse-grained sandstone.[2] Groundwater at the site occurs between elevation 0 and 1.5 m (4.8 ft) Mean Low-Low Water, under water table conditions. The basemat of the reactors would be beneath the water table.

The groundwater gradient is clearly toward the ocean. There are no wells between the site and the ocean, so no groundwater users could be affected by an accidental contamination from the plant. There is virtually no possibility of a reversal of the groundwater gradient due to heavy pumping inland, particularly because such a reversal would at the same time cause an unacceptable intrusion of saltwater into the aquifer. Therefore, liquid radioactivity released from a core melt accident could only cause contamination by being transported through the groundwater and subsequently released to the Pacific Ocean.

The staff's most conservative estimate of the groundwater travel time would be 215 days. For groundwater travel times of this magnitude, it is clear that the most important radionuclide contributors to the liquid pathway population dose would be Sr-90 and Cs-137. Conservative values of the retardation factors, which reflect the effects of sorption of the radionuclides on geologic materials, were estimated on media similar to the granular materials under the site[14] to be 31 for Sr-90 and 2204 for Cs-137. The mean transport time from the reactor building to the Pacific Ocean is therefore conservatively estimated to be about 16 years for Sr-90 and 1080 years for Cs-137. When these travel times are compared to 5.7 years for Sr-90 and 51 years for Cs-137 in the LPGS land-based ocean site case, the relatively larger travel times for the San Onofre site would allow a smaller portion of the radioactivity to enter the surface water. This reduces the Sr-90 release to about 78% of the LPGS value. Virtually all of the Cs-137 would have decayed before reaching surface water.

Contaminants released from the shoreline would disperse in the oceanic turbulence. The LPGS made no distinction between the turbulence which would be found in the east, gulf, or west coasts of the United States. The only assumption which can be made without site-specific data is that the mixing at the San Onofre and LPGS sites are similar.

The two major liquid pathway exposure pathways for an ocean site are aquatic food consumption and direct shoreline exposure.

The commercial and recreational finfish harvest for a rectangular block 80 km along shore and stretching 40 km offshore has been estimated by the staff from data provided in the

Environmental Report[15] to be about 13.1×10^6 kg. For comparison, the same size block using the LPGS ocean site fish catch densities would yield 5.8×10^6 kg of finfish.

Approximately 62% of population dose due to finfish consumption calculated in the LPGS was due to Cs-137 and approximately 38% was due to Sr-90. The only significant radionuclide which could reach the ocean in the San Onofre case would be Sr-90. The staff has conservatively estimated that the uninterdicted population dose in the San Onofre case would be about 69% of the LPGS land-based ocean case population dose for seafood consumption.

Nearly all of the direct shoreline exposure in the LPGS ocean-based site case was determined to emanate from Cs-137. Since virtually all of the Cs-137 would decay before reaching the ocean, the shoreline direct exposure can be eliminated from further consideration.

The San Onofre liquid pathway contribution to population dose has, therefore, been demonstrated to be smaller than that predicted for the LPGS land-based ocean site, which represents a "typical" ocean site. Thus, the San Onofre site is not unique in its liquid pathway contribution to risk.

There are measures which could be taken to minimize the impact of the liquid pathway. The staff estimated that the minimum groundwater travel time from the San Onofre site to the Pacific Ocean would be hundreds of days. In addition, the holdup of important radionuclides would provide additional time to utilize engineering measures such as slurry walls and well-point dewatering to isolate the radioactive contaminants at the source.

7.1.4.6 Risk considerations

The foregoing discussions have dealt with both the frequency (or likelihood of occurrence) of accidents and their impacts (or consequences). Since the ranges of both factors are quite broad, it is useful to combine them to obtain average measures of environmental risk. Such averages can be particularly instructive as an aid to the comparison of radiological risks associated with accident releases and with normal operational releases.

A common way in which this combination of factors is used to estimate risk is to multiply the probabilities by the consequences. The resultant risk is then expressed as a number of consequences expected per unit of time. Such a quantification of risk does not at all mean that there is universal agreement that people's attitudes about risk, or what constitutes an acceptable risk, can or should be governed solely by such a measure. At best, it can be a contributing factor to a risk judgment, but not necessarily a decisive factor.

In Table 7.5 are shown average values of risk associated with population dose, acute fatalities, latent fatalities, and costs for evacuation and other protective actions. These average values are obtained by summing the probabilities multiplied by the consequences over the entire range of the distributions. Since the probabilities are on a per-year basis, the averages shown are also on a per-year basis.

Table 7.5 Annual Average Values of Environmental Risks Due to Accidents

Population exposure	
man-rem within 80 km	170
man-rem total	380
Acute fatalities	
permanent residents	0.001
beach visitors	0.00002
Latent cancer fatalities	
all organs excluding thyroid	0.022
thyroid only	0.011
Cost of protective actions and decontamination	$19,000

NOTE: See Section 7.1.4.6 for discussions of uncertainties in risk estimates.

The population exposure risk due to accidents may be compared with that for normal operational releases. These are shown in Section 5, Tables 5.3 and 5.5, for San Onofre Units 2 and 3 operating concurrently. The radiological dose to the population from normal operational releases may result in:

(1) late somatic effects in the form of fatal and nonfatal cancer in various body organs--following age and organ-specific latency periods--of the exposed population, and

(2) fatal and nonfatal genetic disorders in the future generations of the exposed population.

Because of the randomness of these effects, calculations of these effects are made from the population dose (man-rem). Absolute risk estimators of 140 deaths from expression of latent cancer in various body organs per 10^6 total-body man-rem in the exposed population and 260 cases of all forms of genetic disorders per 10^6 total-body man-rem in the future generations of the exposed population were derived from the 1972 BEIR report.[5] This derivation assumes a linear and nonthreshold dose-effect relationship at all sublethal dose levels. Using these risk estimators and 228 man-rem as the annual population dose (Table 5.5, adjusted for one reactor), the staff calculated that there may occur 0.03 cancer deaths in the exposed population and 0.06 genetic disorders in all future generatons of the exposed population from each year of operation of one reactor.

The comparison of 0.03 cancer deaths given above with about the same value for latent cancer deaths from Table 7.1.4-5 shows that the accident risks are comparable to those for normal operational releases.

There are no acute fatality nor economic risks associated with protective actions and decontamination for normal releases; therefore, these risks are unique for accidents. For perspective and understanding of the meaning of the acute fatality risk of 0.001 per year, however, the staff notes that to a good approximation the population at risk is that within about 16 km (10 mi) of the plant, about 92,000 persons in the year 2000. Accidental fatalities per year for a population of this size, based upon overall averages for the United States, are approximately 20 for motor vehicle accidents, 7 from falls, 3 from drowning, 3 from burns, and 1 from firearms (ref. 5, p. 577).

As a separate item under acute fatalities in Table 7.5 is an entry of 0.00002 for "Beach visitors." As discussed in Section 7.1.3.2, the beaches near the site are heavily used for recreation. The average number of visitors has been estimated, based on seasonal and daily variation. The effects on the visitors are tallied separately because in actuality they are likely to be permanent residents from other nearby locations.

Figure 7.7 shows the calculated risk expressed as whole-body dose to an individual from early exposure as a function of the distance from the plant within the plume exposure pathway EPZ. The values are on a per-reactor-year basis and all accident sequences and release categories in Table 7.3 contributed to the dose, weighted by their associated probabilities. Calculated risk to an individual living within the plume exposure pathway EPZ of San Onofre of acute death due to potential accidents in the reactor is shown in Figure 7.8 as curves of constant risk per year to an individual as a function of distance due to potential reactor accidents. Figure 7.9 shows the same type of isopleths for death from latent cancer. Directional variation of these curves reflect the variation in the average fraction of the year the wind would be blowing into different directions from the plant. For comparison the following risk of fatality per year to an individual living in the U.S. may be noted (ref. 4, p. 577); automobile accident 2.2×10^{-4}, falls 7.7×10^{-5}, drowning 3.1×10^{-5}, burning 2.9×10^{-5}, and firearms 1.2×10^{-5}.

The economic risk associated with protective actions and decontamination could be compared with property damage costs associated with alternative energy generation technologies. The use of fossil fuels, coal or oil, for example, would emit substantial quantities of sulfur dioxide and nitrogen oxides into the atmosphere, and, among other things, lead to environmental and ecological damage through the phenomenon of acid rain (Ref. 4, 559-560). This effect has not, however, been sufficiently quantified to draw a useful comparison at this time.

There are other economic impacts and risks that can be monetized that are not included in the cost calculations discussed in Section 7.1.4.4. These are accident impacts on the facility itself that result in added costs to the public, i.e., ratepayers, taxpayers, and/or shareholders. These are costs associated with decontamination of the facility itself and costs for replacement power.

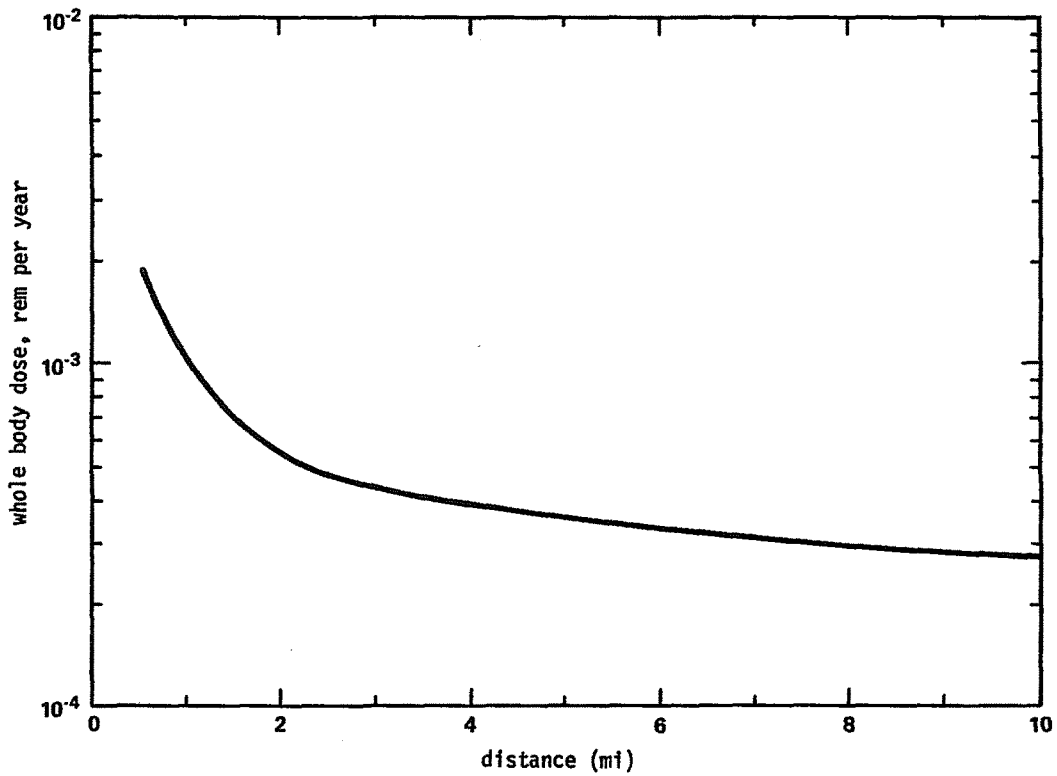

Figure 7.7 Individual risk of dose as a function of distance. (To convert mi to km, multiply by 1.6.)

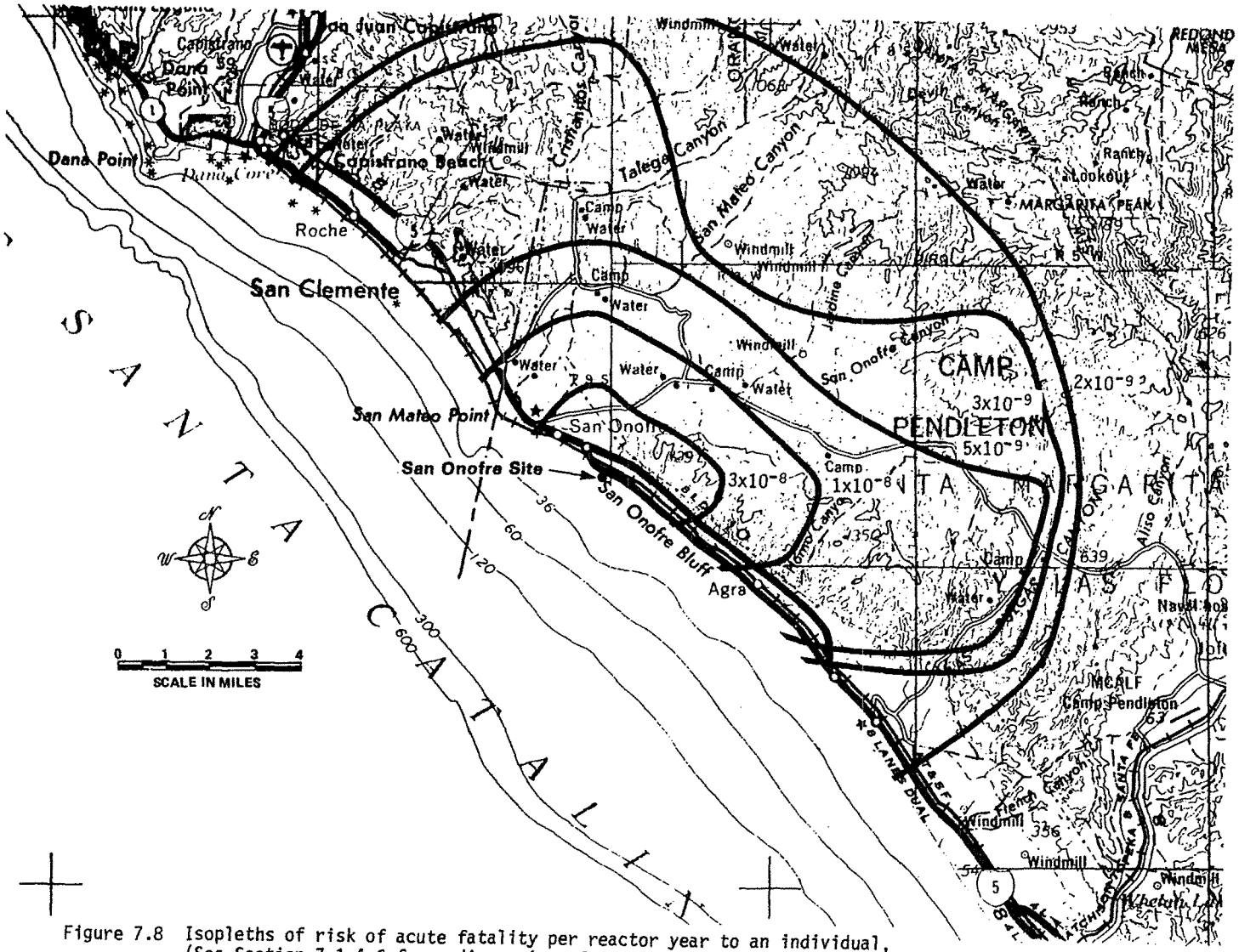

Figure 7.8 Isopleths of risk of acute fatality per reactor year to an individual. (See Section 7.1.4.6 for a discussion of uncertainties in risks estimates.) (To convert miles to kilometers, multiply by 1.6.)

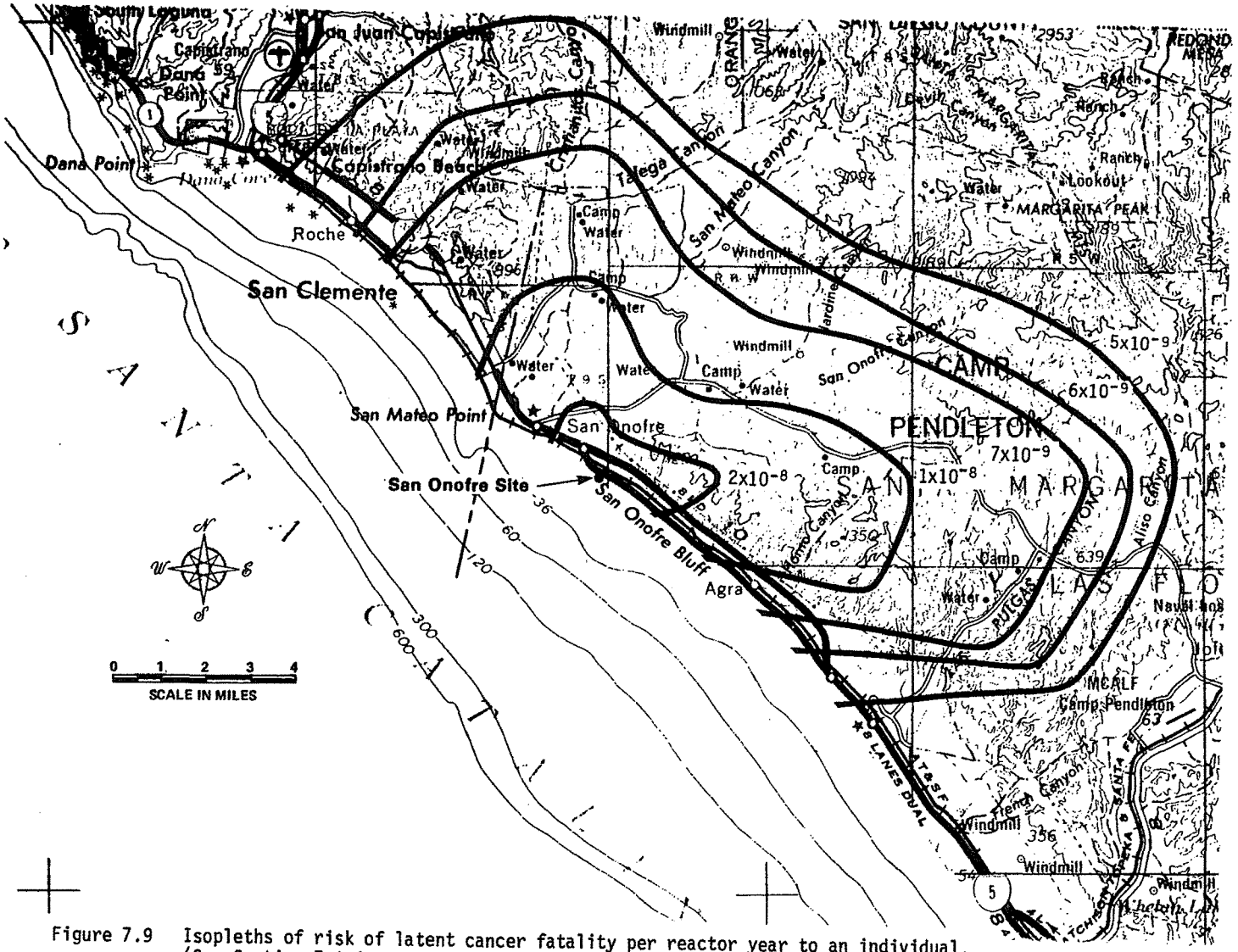

Figure 7.9 Isopleths of risk of latent cancer fatality per reactor year to an individual. (See Section 7.1.4.6 for a discussion of uncertainties in risks estimate.) (To convert miles to kilometers, multiply by 1.6.)

No detailed methodology has been developed for estimating the contribution to economic risk associated with cleanup and decontamination of a nuclear power plant that has undergone a serious accident toward either a decommissioning or a resumption of operation. Experience with such costs is currently being accumulated as a result of the Three Mile Island accident. It is already clear, however, that such costs can approach or even exceed the original capital cost of such a facility. As an illustration of the possible contribution to the economic risk, if the probability of an accident serious enough to require extensive cleanup and decontamination is taken as the sum of the nine categories in Table 7.3, i.e., about 5 chances in 10,000 per year, and if the "average" decontamination cost for these nine categories is assumed to be one billion dollars, then the estimated economic risk would be about $500,000 per year.

Other costs, besides damage to or loss of the facility, result from accidents. The major additional costs are replacement power and replacement of the capacity. These costs are affected by the point in the lifetime of the plant at which an accident might occur. The present worth cost is highest for an accident occurring at the beginning of the plant operating life and decreases over the plant life. It is assumed for these calculations that one unit of San Onofre 2 or 3 is permanently lost and replaced by new capacity after eight years and the undamaged unit is shut down for three years before restart. For illustrative purposes, the costs and economic risk have been estimated for a "worst case" situation for the approximately 2200-megawatt (electric) San Onofre Units 2 and 3 complex by postulating a total loss of one of the units in the first year of a projected 30-year operating life. Net replacement power cost of 45 mills/kWh is assumed (nearly all fossil units in southern California are oil-fired). Using a 60% capacity factor, the annual cost of replacement power would be $520 million for the two units in 1980 dollars. The additional capital costs as a result of having to construct a new facility are $60 million per year, again in 1980 dollars.

If the probability of sustaining a total loss of the original facility is taken as the probability of the occurrence of a core melt accident (approximately by the sum of probabilities for the categories PWR-1 through 7 in Table 7.3, i.e., about 5 chances in 100,000 per year), then the average contribution to economic risk that would result from a loss early in the operating life of a San Onofre unit is about $29,000 for each of the first three years until the undamaged plant is returned to service, then $16,000 per year until the damaged unit is replaced, and $3000 per year additional capital costs for the assumed remaining 22 years of plant service.

7.1.4.7 Uncertainties

The foregoing probabilistic and risk assessment discussion has been based upon the methodology presented in the Reactor Safety Study (RSS),[10] which was published in 1975.

In July 1977, the NRC organized an Independent Risk Assessment Review Group to (1) clarify the achievements and limitations of the Reactor Safety Study Group, (2) assess the peer comments thereon and the responses to the comments, (3) study the current state of such risk assessment methodology, and (4) recommend to the Commission how and whether such methodology can be used in the regulatory and licensing process. The results of this study were issued September 1978.[11] This report, called the Lewis Report, contains several findings and recommendations concerning the RSS. Some of the more significant findings are summarized below.

(1) A number of sources of both conservatism and nonconservatism in the probability calculations in RSS were found, which were very difficult to balance. The Review Group was unable to determine whether the overall probability of a core melt given in the RSS was high or low, but they did conclude that the error bands were understated.

(2) The methodology, which was an important advance over earlier methodologies that had been applied to reactor risk, was sound.

(3) It is very difficult to follow the detailed thread of calculations through the RSS. In particular, the Executive Summary is a poor description of the contents of the report, should not be used as such, and has lent itself to misuse in the discussion of reactor risk.

On January 19, 1979, the Commission issued a statement of policy concerning the RSS and the Review Group Report. The Commission accepted the findings of the Review Group.

The accident at Three Mile Island occurred in March 1979 at a time when the accumulated experience record was about 400 reactor years. It is of interest to note that this was within the range of frequencies estimated by the RSS for an accident of this severity (ref. 4, p. 533). It should also be noted that the Three Mile Island accident has resulted in a very comprehensive evaluation of reactor accidents like that one, by a significant number of investigative groups both within NRC and outside of it. Actions to improve the safety of nuclear power plants have come out of these investigations, including those from the President's Commission on the Accident at Three Mile Island, and NRC staff investigations and task forces. A comprehensive "NRC Action Plan Developed as a Result of the TMI-2 Accident," NUREG-0660, Vol. I, May 1980 collects the various recommendations of these groups and describes them under the subject areas of: Operational Safety; Siting and Design; Emergency Preparedness and Radiation Effects; Practices and Procedures; and NRC Policy, Organization and Management. The action plan presents a sequence of actions, some already taken, that will result in a gradually increasing improvement in safety as individual actions are completed. The San Onofre plant is receiving and will receive the benefit of these actions on the schedule indicated in NUREG-0660. The improvement in safety from these actions has not been quantified, however, and the radiological risk of accidents discussed in this chapter does not reflect these improvements.

7.1.5 Conclusions

The foregoing sections consider the potential environmental impacts from accidents at the San Onofre facility. These have covered a broad spectrum of possible accidental releases of radioactive materials into the environment by atmospheric and groundwater pathways. Included in the considerations are postulated design basis accidents and more severe accident sequences that lead to a severely damaged reactor core or core melt.

The environmental impacts that have been considered include potential radiation exposures to individuals and to the population as a whole, the risk of near- and long-term adverse health effects that such exposures could entail, and the potential economic and societal consequences of accidental contamination of the environment. These impacts could be severe, but the likelihood of their occurrence is judged to be small. This conclusion is based on (a) the fact that considerable experience has been gained with the operation of similar facilities without significant degradation of the environment; and (b) a probabilistic assessment of the risk based upon the methodology developed in the Reactor Safety Study. The overall assessment of environmental risk of accidents, assuming protective action, shows that it is roughly comparable to the risk for normal operational releases although accidents have a potential for acute fatalities and economic costs that cannot arise from normal operations. The risk of acute fatalities from potential accidents at the site are small in comparison with the risk of acute fatalities from other human activities in a comparably-sized population.

The staff has concluded that there are no special or unique features about the San Onofre site and environs that would warrant special or additional engineered safety features for the San Onofre plants.

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*Available for inspection and copying for a fee in the NRC Public Document Room, 1717 H St. N. W., Washington, DC 20555.
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8. NEED FOR THE STATION

8.1 RESUME

The ownership of Units 2 and 3 of the San Onofre Nuclear Generating Station is divided among Southern California Edison Company (SCE), 76.55%; San Diego Gas & Electric Company (SDG&E) 20%; the City of Riverdale, California, 1.79%; and the City of Anaheim, California, 1.66%. This section presents an analysis of the need for the station based on the energy demands of the applicant's service areas, the potential for production cost savings, and the potential for increasing the reliability of the applicant's systems.

8.2 APPLICANT'S SERVICE AREAS AND REGIONAL RELATIONSHIPS

8.2.1 Applicant's service areas

Southern California Edison Company's service area extends over a 15-county area of southern and central California, covering about 130,000 km^2 (50,000 mi^2) and containing a population in excess of 7.5 million. In 1978, SCE served 2.95 million customers, over 88% of which were residential. San Diego Gas & Electric Company supplies electricity to about 700,000 customers in San Diego County and in portions of Orange and Imperial counties. The boundaries of the service area enclose a 10,630-km^2 (4105-mi^2) area. The cities of Anaheim and Riverside serve their respective municipalities. A map of the applicant's service area is presented in Figure 8.1.

8.2.2 Regional relationships

SCE and SDG&E are members of the Western Systems Coordinating Council (WSCC) and the California Power Pool (CPP). The WSCC is the regional reliability council for the interconnected power network that serves the states west of the Rockies and parts of British Columbia. Established in 1967, the WSCC's primary function is to facilitate coordinated planning among its member systems and to provide technical support. In relation to these duties, the WSCC compiles load and resource data for the region, performs reliability studies, and recommends minimum reserve criteria. The California Power Pool, whose members are Pacific Gas & Electric Company (PG&E), SCE, and SDG&E, was formed in 1964 to provide for the continuous interconnected operation of the member utilities' power supply systems. This interconnected operation allows the utilities to make more efficient, and therefore more economical use of their generation resources and increases the overall reliability of electric service.

8.3 BENEFITS OF STATION OPERATION

8.3.1 Minimization of production costs

To minimize energy production costs, it is necessary to use the most economical mix of generation resources. The impact of the operation of SONGS 2 & 3 on the applicant's total cost of generation will be a major factor in determining the desirability of such operation. In assessing this impact, it is important to note that the fixed costs of each facility, such as the sunken capital investment and the fixed portion of the operating and maintenance costs, are irrelevant to the choice of which generation resources will be used to meet a given load, precisely because these costs are fixed and will not vary with an altered mode of system operation.

To assess the impact of station operation on the applicant's overall production costs, the staff first reviewed the latest production costs reported by the applicants for their electric generation stations. These data, presented in Tables 8.1 and 8.2, show that all oil/gas- and oil-fired facilities that are listed as base and/or intermediate units had production costs ranging from $29.2 to $56.7 per MWh, whereas Unit 1 of the San Onofre Nuclear Generating Station had a production cost of $9.0/MWhr. In determining how the additional units of the San Onofre Station would compare with these figures, the staff estimated the 1983 fuel cost for these units to be $10.8/MWhr.[1] Because SCE's and SDG&E's installed capacity is predominately oil- and oil/gas-fired, the staff concludes

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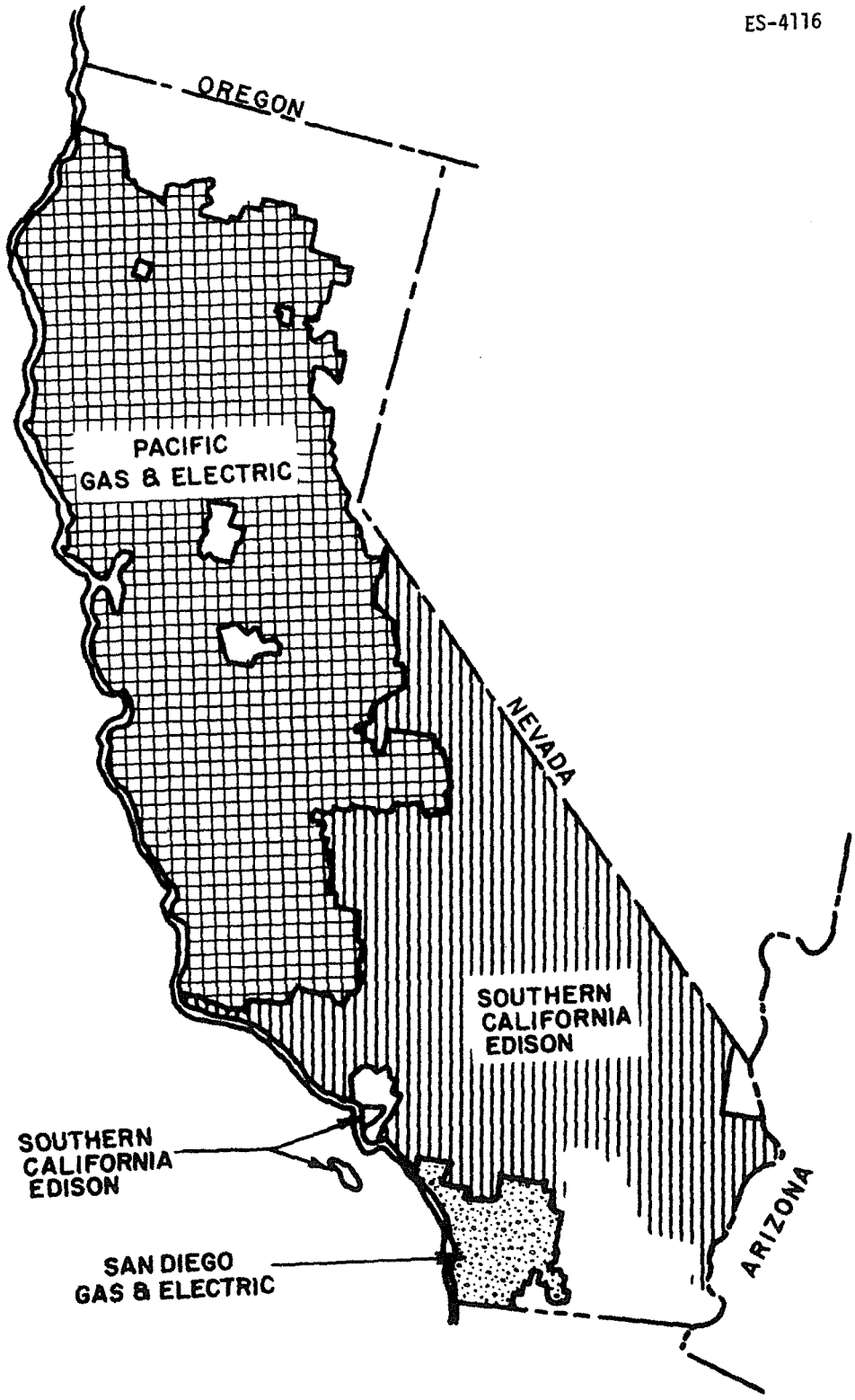

Fig. 8.1. Service areas of the member utilities of the California Power Pool. Source: ER, p. S.2-193.

Table 8.1. Southern California Edison Co. thermal-electric generating stations and production costs

Station Name	On-line dates for first and last unit	Function	Fuel type	Total station capacity (MW)	1980 Production cost (dollars/MWh)*
Long Beach	1928-1977	P	Oil/gas	156 530	77.9 38.1
Redondo Beach	1948-1967	B, I	Oil/gas	642	41.5 31.8
Huntington Beach	1958-1969	I, P	Oil/gas	870 114	39.3 49.2
Mandalay	1959-1970	I, P	Oil/gas	430 117	44.0 94.7
Ormond Beach	1971-1973	I	Oil/gas	1,500	50.6
Alamitos	1956-1969	B, I, P	Oil/gas	990 960 114	41.6 45.5 80.7
El Segundo	1955-1965	I	Oil/gas	1,020	41.8
Etiwanda	1953-1969	I, P	Oil/gas	904 108	42.2 71.8
Mohave	1971	B	Coal	885	11.8
Four Corners	1969-1970	B	Coal	768	4.6
San Onofre Unit 1	1967	B	Nuclear	349	9.0
Coolwater	1961-1978	I	Oil/gas	146 482	29.2 56.7
Highgrove	1952-1955	P	Oil/gas	154	50.5
San Bernardino	1957-1958	P	Oil/gas	126	35.0
Garden State	1967	P	Oil/gas	12	67.0
Ellwood	1974	P	Oil/gas	48	61.6

Note: B = base, I = intermediate, and P = peaking.
*Fuel only.
Source: Letter from K. P. Baskin, Southern California Edison Co., to Frank Miraglia, USNRC, undated; received by USNRC on February 25, 1981.

Table 8.2. San Diego Gas & Electric Co. thermal-electric generating stations and production costs

Station Name	On-line dates for first and last unit	Function	Fuel type	Total station capacity (MW)	1979 Production cost (dollars/MWh)
Station "B"	1923-1941	P	Oil/gas	90	188.8
Silver Gate	1943-1952	I	Oil/gas	230	48.9
Encina	1954-1978	B	Oil/gas*	917	33.7
Encina GT	1968	P	Oil/gas	16	98.6
South Bay	1960-1971	B	Oil/gas	706	33.7
South Bay GT	1966	P	Jet Fuel	18	233.4
San Onofre Unit 1	1967	B	Nuclear	87**	9.3
El Cajon	1968	P	Oil/gas	17	62.2
Kearny	1969	P	Oil/gas	147	77.5
Division	1968	P	Oil	16	97.6
Naval Training Center	1968	C	Oil/gas	16	46.0
Miramar	1972	P	Oil/gas	38	53.1
North Island	1972	P/C	Oil	41	43.7
Naval Station	1976	C	Oil/gas	26	41.0
Rohr	1979	C	Oil	1	75.8

Note: P = peaking, I = intermediate, B = base, and C = Cogeneration.
*Encina Unit 5 (320 MW) oil only.
**SDG&E's 20% share.
Source: Letter from K. P. Baskin, Southern California Edison Co., to V. A. Moore, USNRC, dated April 11, 1980.

that the operation of SONGS Units 2 and 3 would tend to reduce reliance on these facilities with corresponding savings in production costs.

To quantify the magnitude of the production cost savings, the staff made a comparison between the fuel cost that would be incurred in 1983 (the first full year in which both units are scheduled for full operation) if the two nuclear units were operated at a combined capacity factor of 50%, and the fuel cost that would be incurred if an oil-fired facility produced the same amount of electricity. In this comparison, the staff assumed a nuclear fuel cost of $10.8/MWhr in 1983, an oil cost of $4.4 per million Btu in 1983, and an oil-fired plant conversion ratio of 9,000 Btu/kWhr. These assumptions lead to an oil cost of $39.6/MWhr. All costs have been adjusted by the Producers Price Index to reflect costs in 1980 dollars. The results show that operating the nuclear units will save $270 million in fuel costs during 1983. Lowering the assumed plant capacity factor to 40% resulted in a fuel cost savings of $210 million, and raising the capacity factor to 60% gave a cost savings of $320 million. The cost of nuclear fuels would have to rise by a factor of about 3-1/2, and the price of oil would have to remain the same for the fuel savings of operating the nuclear units to disappear. These results, coupled with the information presented in Tables 8.1 and 8.2, clearly indicate that the applicant's production costs will be reduced significantly by the operation of SONGS 2 & 3.

8.3.2 Energy demand

Table 8.3 presents SCE's forecasts of peak demand, energy requirements, installed generating capacity, and reserve margins through 1985. These projections indicate that without SONGS 2 & 3 reserve margins fall below 13% from 1982-84 and dip to 7.1% in 1985. From 1980-85 SCE forecasts peak demand to grow at an average annual rate of 2.8%. A comparison with the State Level Electricity Demand[2] (SLED) forecasting model developed at Oak Ridge National Laboratory indicates that over the same period the electrical energy demand in California is forecasted to grow at an average annual rate of 4.5%. SCE's projected reserve margins without SONGS 2 & 3 clearly indicates a need for this capacity to maintain system reliability. The comparison of the applicant's forecasts of demand with the SLED forecasts reinforces the need for the additional capacity and reserve margins provided by SONGS 2 & 3.

Table 8.3. Southern California Edison Co. forecasts of peak demand, energy requirements, installed generating capacity, and reserve margins through 1985[a]

Year	Area peak demand (MW)	Growth[b] (%)	Total energy requirements kWh × 10^6	Growth[b] (%)	Installed Capacity (MW)		Reserve Margin (%)	
					With SONGS 2 & 3	Without SONGS 2 & 3	With SONGS 2 & 3	Without SONGS 2 & 3
1976	11292		59428		14071	14071	24.6	24.6
1977	11564	2.4	63345	6.6	14278	14278	23.5	23.5
1978	12159	2.9	63877	0.8	14966	14966	23.1	23.1
1979	12662	4.1	66217	3.7	15071	15071	19.0	19.0
1980	12841	1.4	65459	-1.1	15504	15504	20.7	20.7
1981	13274	3.4	67120	2.5	15471	15471	16.6	16.6
1982	13647	2.1	67910	1.2	16184	15304	18.6	12.1
1983	13895	1.8	70220	3.4	17446	15686	25.6	12.9
1984	14305	3.0	72590	3.4	17837	16077	24.7	12.4
1985	14735	3.0	75130	3.5	17535	15775	19.0	7.1

[a]Per November 18, 1980 Resource Plan.
[b]Percentage increase over previous year. 1976 through 1980 is recorded.
Source: Letter from K. P. Baskin, Southern California Edison Co., to Frank Miraglia, USNRC, undated, received by USNRC on February 25, 1981.

Table 8.4 provides analogous projections of electricity demand, installed capacity, and reserve margins for SDG&E. Without SONGS 2 & 3 reserve margins drop below 15% in 1984 and below 10% in 1985. The average annual growth in peak demand has been forecast at 1.3% which is significantly below the 4.5% rate forecast by SLED[2] for electrical energy demand in the State of California. Reserve margins forecast by SDG&E indicate a need for

Table 8.4. San Diego Gas & Electric Co. forecasts of peak demand, energy requirements, installed generating capacity, and reserve margins through 1987

Year	Area peak demand[a] (MW)	Growth[b] (%)	Energy requirements kWh × 10^6	Growth[b] (%)	Installed Capacity (MW)[c]		Reserve Margin (%)[c]	
					With SONGS 2 & 3	Without SONGS 2 & 3	With SONGS 2 & 3	Without SONGS 2 & 3
1978[d]	1981	13.5	10053	7.8	2030	2030	2.5	2.5
1979[d]	2019	1.9	10548	4.9	2363	2363	17.0	17.0
1980[d]	2050	3.7	10403	-1.4	2401[e]	2401[e]	17.1	17.1
1981	1975	-3.7	10738	3.2	2366	2366	19.8	19.8
1982	2004	1.5	10824	0.8	2586	2366	29.0	18.1
1983	2033	1.4	11108	2.6	2806	2366	38.0	16.4
1984	2077	2.2	11407	2.7	2806	2366	35.1	13.9
1985	2184	5.2	11762	3.1	2806	2366	28.5	8.3
1986	2272	4.0	12244	4.1	2806	2366	23.5	4.1
1987	2361	3.9	12763	4.2	2806	2366	18.8	0.0

[a] 1981–1987 SDG&E CFM III Forecast adopted by California Energy Commission in December 1980.
[b] Percentage increase over previous year.
[c] Excludes purchased capacity.
[d] 1978 through 1980 are recorded.
[e] July net rating.
Source: Letter from K. P. Baskin, Southern California Edison Co., to Frank Miraglia, USNRC, undated, received by USNRC on February 25, 1981.

SONGS 2 & 3 to maintain system reliability. Once again comparing the applicant's forecasts to the SLED forecasts reinforces the need for the additional capacity and reserve margins provided by SONGS 2 & 3.

The staff concludes on the basis of the analysis of the applicant's projected reserve margins that operation of SONGS 2 & 3 will be needed to ensure reliability within the time frame that operation is anticipated to begin. Furthermore, the analysis of cost savings due to a shift from oil-fired to nuclear generation (Sect. 8.3.1) makes operation of SONGS 2 & 3 economically desirable independent of load forecasts.

REFERENCES

The documents references below are available from the NRC/GPO Sales Program, Washington, DC 20555 and the National Technical Information Service, Springfield, VA 22161.

1. J. O. Roberts, S. M. Davis, and D. A. Nash, "Coal and Nuclear: A Comparison of the Cost of Generating Baseload Electricity by Region," U.S. Nuclear Regulatory Commission Report NUREG-0480, December 1978.

2. W. S. Chern, J. W. Dick, C. A. Gallagher, B. D. Holcomb, R. E. Just, and H. D. Nguyen, "The ORNL State-Level Electricity Demand Forecasting Model," Oak Ridge National Laboratory Report ORNL/NUREG-63, July 1980.

9. CONSEQUENCES OF THE PROPOSED ACTION

9.1 ADVERSE EFFECTS THAT CANNOT BE AVOIDED

The staff has reassessed the physical, social, and economic impacts that can be attributed to SONGS 2 & 3. The identification of adverse effects that cannot be avoided, given in Chap. 8 of the FES-CP, remains valid. The major effects identified were the destruction of a small amount of wildlife habitat in the area occupied by the plant buildings and the loss of fish and other marine organisms that will be entrained in the circulating cooling water system. In addition, construction has resulted in the excavation of about 16.4 ha (40.5 acres) of the San Onofre Bluffs, and operation of the plant will result in the removal of approximately 1.4 km (0.85 mile) of beach from unrestricted public use.

9.2 SHORT-TERM USES AND LONG-TERM PRODUCTIVITY

The assessment of the short-term uses and long-term productivity contained in Chap. 9 of the FES-CP remains valid. About 21 ha (52 acres) of the total of 36 ha (90 acres) comprising all three units will be devoted to the production of electrical energy for the next 30 to 40 years. If, at the end of this period, the site is no longer needed for the production of electrical energy, it could be used for other purposes (see Sect. 9.4, below).

9.3 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

There has been no change in the staff's assessment of these commitments since the earlier review (FES-CP, Chap. 10) except that the continuing escalation of costs has increased the dollar values of the materials used for construction and for fueling the plant. The staff has, however, expanded and updated the discussion on uranium fuel availability. This updated discussion is presented below.

9.3.1 Replaceable components and consumable materials

Uranium is the principal natural resource irretrievably consumed in facility operation. Other materials consumed, for practical purposes, are fuel-cladding materials, reactor-control elements, other replaceable reactor core components, chemicals used in processes such as water treatment and ion-exchanger regeneration, ion-exchange resins, and minor quantities of materials used in maintenance and operation. Except for the uranium isotopes U-235 and U-238, the consumed resource materials have widespread use; therefore, their use in the proposed operation must be reasonable with respect to needs in other industries. The major use of the natural isotopes of uranium is for production of useful energy.[1]

The reactor will be fueled with uranium enriched in the isotope U-235. After use in the plant, the fuel elements will still contain U-235 slightly above the natural fraction. This slightly enriched uranium, if separated from plutonium and other radioactive materials (separation would take place in a chemical reprocessing plant), would be available for recycling through the gaseous diffusion plant if required. Scrap material containing valuable quantities of uranium may also be recycled through appropriate steps in the fuel production process. Should chemical reprocessing of spent fuel be effected in the future, the fissionable plutonium recovered is potentially valuable for fuel in power reactors.

In view of the quantities of materials in natural reserves, resources, and stockpile and the quantities produced yearly, the expenditure of such material for the power facility is justified by the benefits from the electrical energy produced. A detailed discussion of uranium supply and demand follows.

9.3.2 Uranium resource availability

This section reviews information available from the Department of Energy (DOE) on the domestic uranium resource situation and the outlook for development of additional domestic supplies, availability of foreign uranium, and the relationship of uranium supply to planned nuclear generating capacity.

Analysis of uranium resources and their availability has been carried out by the government since the late 1940's. The work was carried out for many years by the Atomic Energy Commission (AEC). The activity was made part of the Energy Research and Development Administration (ERDA) when the agency was created in early 1975[1] and was subsequently transferred to the DOE when it was formed October 1, 1977.

9.3.2.1 U.S. resource position

To establish some basic terminology, a review of resource concepts and nomenclature would be worthwhile. Figure 9.1 defines resource categories based on varying geologic knowledge. Resources designated as ore reserves have the highest assurance regarding their magnitude and economic availability. Estimates of reserves are based on detailed sampling data, primarily from gamma ray logs of drill holes. DOE obtains basic data from industry from its exploration effort and estimates the reserves in individual deposits. In estimating ore reserves, detailed studies of feasible mining, transportation, and milling techniques and costs are made. Consistent engineering, geologic and economic criteria are employed. The methods used are the result of over 30 years of effort in uranium resource evaluation.

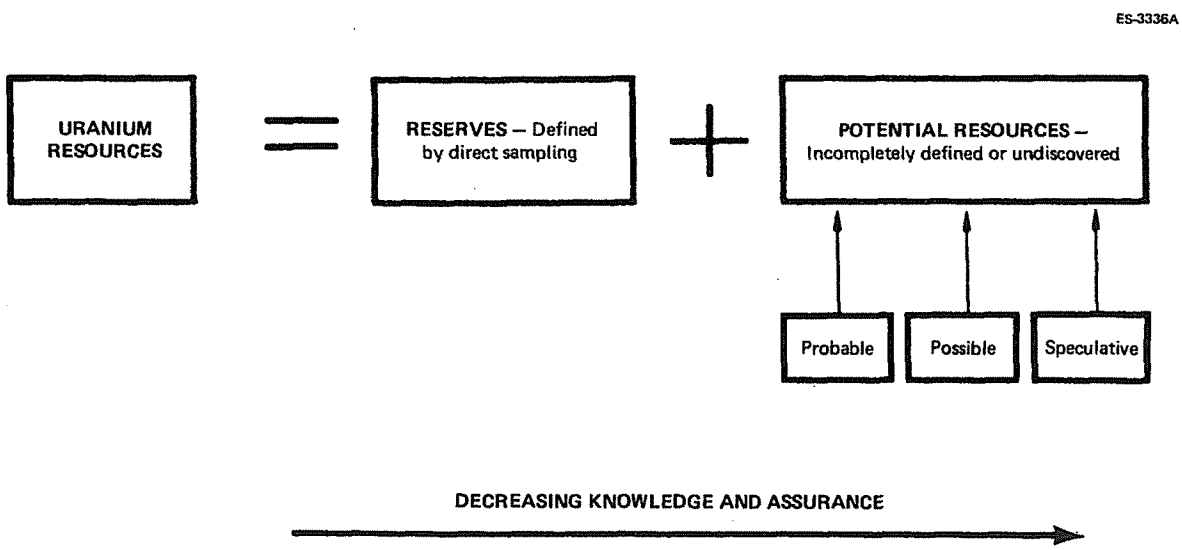

Fig. 9.1. DOE uranium resource categories.

Resources that do not meet the stringent requirements of reserves are classed as potential resources. For its study of resources, DOE subdivides potential resources into three categories: probable, possible, and speculative.[2] Probable potential resources are those contained within favorable trends, largely delineated by drilling, within productive uranium districts, i.e., those having more than 10 tons of U_3O_8 production and reserves. Quantitative estimates of potential resources are made by considering the extent of the identified favorable areas and by comparing certain geologic characteristics with those associated with known ore deposits.

Possible potential resources are outside of identified mineral trends but are in geologic provinces and formations that have been productive. Speculative resources are those estimated to occur in formations or geologic provinces which have not been productive but which, based on the evaluation of available geologic data, are considered to be favorable for the occurrence of uranium deposits.

Because any evaluation of resources is dependent upon the availability of information, the estimates themselves are, to a large degree, a scorecard on the state of development of information. Thus, appraisal of U.S. uranium resources is heavily dependent on the completeness of exploration efforts and the availability of subsurface geologic data. Since the geology of the United States as it relates to mineral deposits can never be completely known in detail, it will not be possible to produce a truly complete appraisal of domestic uranium resources. It is likely that the total resource picture will eventually prove larger than currently estimated given the nature and status of estimation methodology. The key factor may be the timeliness with which resources are identified, developed, and produced.

Conceptually, a resource, whether uranium or other mineral commodity, would initially be in the potential category. Development of additional data and clarification of production techniques and economics would be required to delineate and understand specific ore deposits to a degree that they could be categorized as reserves.

We can expect a dynamic balance between anticipated markets and prices and the extent to which exploration and reserve delineation will be done. There is no economic incentive for industry to expand reserves if the additional uranium will not be needed for many years ahead, and especially if the long-term market outlook is uncertain. This has been true for uranium. The mining companies are concentrating on markets for the next 5 to 15 years. The utilities and government are concerned with the outlook for the next 30 to 40 years.

Conversion of the currently estimated potential resources into ore reserves will take many years and will cost several billion dollars. It would be difficult to economically justify accelerating such an effort to delineate ore reserve levels equal to lifetime requirements of all planned reactors covering some 30 to 40 years in the future simply to satisfy planners. Supply assurance through continued timely additions to reserves and maintenance of a resource base adequate to support production demands, coupled with carefully developed information on potential resources, is considered to be adequate and a more realistic and economic approach. The conversion of potential resources to ore reserves and expansion of production facilities can be accomplished when needed as markets expand and production is needed.

All uranium resource estimates made by DOE and its predecessor agencies before 1979 were single estimates of tons of ore and grade for various cost categories. The estimtes were made by experienced geologists and engineers according to standard procedures, and represented a reasonable measure of resources. The current procedures for estimating uranium resources provide both mean values and distributions to characterize the reliability of the estimates at specific confidence levels. All available geologic information and the expertise of the estimators are fully utilized. These procedures are standardized and documented to minimize personal biases and to facilitate reviews and revisions as new information is acquired.

The estimates of resources in the United States are developed from a data base accumulated during the past three decades of Government and industry activities and enhanced by National Uranium Resource Evaluation program investigations of the past five years. Data acquired to support resource assessment have been extensive and varied. The assessment includes the evaluation of several hundred thousand industry-drilled holes; aerial radiometric surveys; sampling and geochemical analyses of groundwater, stream water, and stream sediment; selective drilling to fill voids in subsurface information; and extensive geologic field examinations. These data have been evaluated to determine those areas favorable for uranium occurrences. Evaluation criteria have been developed from studies of uranium deposits throughout the world. In favorable areas, the uranium endowment, material greater than 0.01 percent U_3O_8, is estimated, and subsequently economic factors are applied to assess the potential resources available at selected costs.

The costs used to calculate uranium resources are forward costs which consider both operating and capital costs, in current dollars, that would be incurred in producing the uranium. These costs include power, labor, materials, royalties, payroll, severance and ad valorem taxes, insurance, and applicable general and administrative costs. All previous expenditures (before the time of the estimate) for such items as property acquisition, exploration, mine development, and mill construction are excluded. Also excluded are income taxes, profit, and the cost of money. The resources assigned to the various cost categories are independent of the market price at which the uranium might be sold.

There are two major methodologies in uranium assessment; one is used for the estimation of reserves based on sample results from drill holes on specific properties; the second involves the use of a variety of geologic information to subjectively estimate potential resources. Reserves are calculated individually for properties throughout the United States using data voluntarily provided by the uranium companies to DOE. The data consist primarily of radiometric drill hole logs and maps. Parameters evaluated include thickness and tenor of mineralized rock; depth and spatial relationships, mining methods, ore dilution, and recovery; and amenability of ores to processing. The amounts of uranium that could be exploited at the forward cost levels are calculated according to conventional engineering practices utilizing available engineering, geologic, and economic data.

A regional reserves distribution estimate is obtained by mathematically combining the estimates of individual distributions for each property. These regional distributions are then combined to provide a total for the United States. Estimates include all material over a selected minimum thickness with a uranium content above 0.01% U_3O_8. A recovery factor is applied, after rate procedures are used for properties on which solution mining is in progress or is planned.

Potential resource estimates are based on geologic analogy. Geologic characteristics related to uranium potential in the area being investigated are compared with those in an area with similar characteristics, that is, a control area that contains uranium deposits for which the frequency distribution of grades and tonnages in the deposits has been developed. The analogy-based methodology is made feasible by DOE's extensive data base from which detailed characterizations of the distribution of uranium have been developed. From systematic comparison with an appropriate control area, an estimate is developed of the total amount of uranium, above 0.01% U_3O_8, that might be present in an area being evaluated. Uranium endowment factors, such as surface area, fraction underlain by endowment, grade, and tonnage are estimated at three confidence levels, i.e., a modal value which is considered as most likely, and a low and high estimate corresponding respectively to a 95 and 5% probability that the factor is at least that large. The endowment estimate is analyzed to determine the portions that are producible at various cost categories within stated confidence levels.

Table 9.1 provides the mean reserve and potential resource estimates for each cost category, as well as estimates at the 95th and 5th percentile. The 95th percentile value provides an estimate for which there is a 95% confidence that at least that amount exists. The 5th percentile provides an estimate for which there is a 5% probability that it will be exceeded. Due to the correlation of the individual estimates that are aggregated to generate the regional and national totals, the estimates at the 95th and 5th percentile are not directly additive; however, the mean values are additive.

Table 9.1. Uranium resources of the United States[a]

Reserves as of January 1, 1980
Other Resources as of October 1, 1980
Tons U_3O_8
Probability distribution values

Forward-cost category	Mean	95th percentile	5th percentile
At $15 per pound of U_3O_8[c]			
Reserves	225,000	190,000	260,000
Probable	295,000	185,000	448,000
Possible	87,000	42,000	156,000
Speculative	74,000	30,000	162,000
Totals	681,000	447,000	1,026,000
At $30 per pound of U_3O_8[b,d]			
Reserves	645,000	567,000	729,000
Probable	885,000	659,000	1,161,000
Possible	346,000	194,000	530,000
Speculative	311,000	155,000	600,000
Totals	2,187,000	1,731,000	2,748,000
At $50 per pound of U_3O_8[b,e]			
Reserves	936,000	821,000	1,060,000
Probable	1,426,000	1,102,000	1,802,000
Possible	641,000	346,000	973,000
Speculative	482,000	251,000	890,000
Totals	3,485,000	2,771,000	4,313,000
At $100 per pound of U_3O_8[b,f]			
Reserves	1,122,000	971,000	1,291,000
Probable	2,080,000	1,646,000	2,573,000
Possible	1,005,000	521,000	1,526,000
Speculative	696,000	378,000	1,225,000
Totals	4,903,000	3,875,000	6,056,000

[a]Uranium resources are estimated quantities recoverable by mining.
[b]Includes lower cost resource categories.
[c]$6.80 per kilogram.
[d]$13.60 per kilogram.
[e]$22.65 per kilogram.
[f]$45.30 per kilogram.
(To convert pounds to kilograms, multiply by 0.454; to convert tons to tonnes, multiply by 0.907.)

Most of the uranium resources are located in a few areas in the Colorado Plateau of New Mexico, Arizona, Colorado, and Utah, in the Wyoming Basins, and in the Texas Gulf Coastal Plain, Figs. 9.2 and 9.3. It should be noted that the reserve estimates in Table 9.1 were as of January 1, 1980, and the lower cost reserves have undoubtedly decreased since that date because of continuing rising costs.

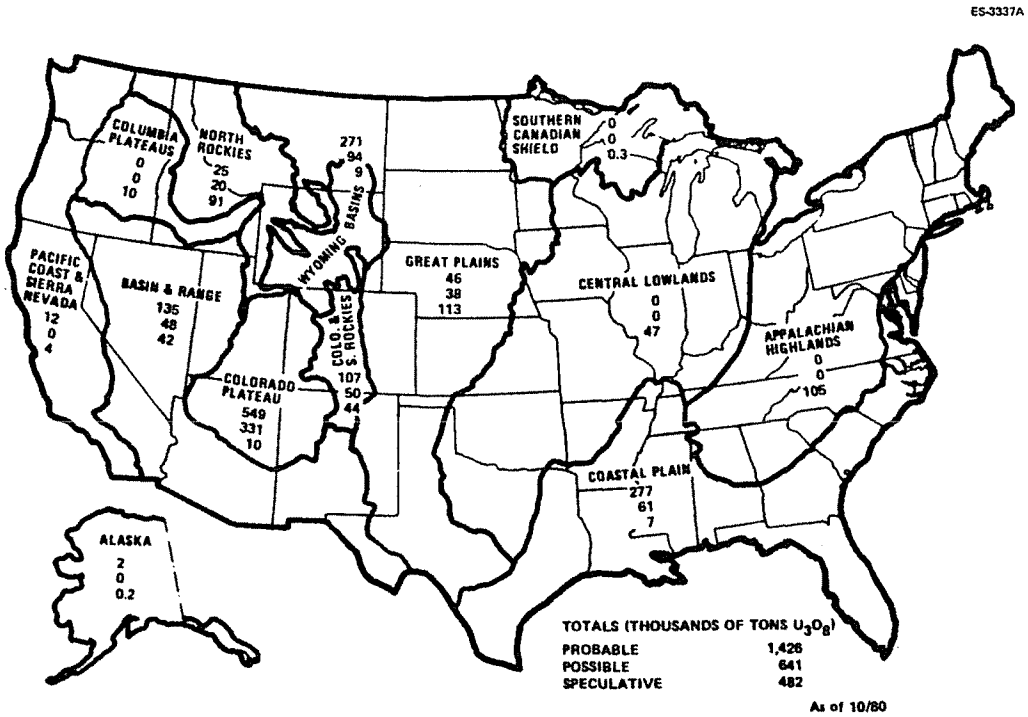

Fig. 9.2. Potential uranium resources by region ($22.65 per kilogram ($50 per pound) of U_3O_8).

9.3.2.2 Uranium exploration activities

Uranium exploration in the United States reached its all time high in 1978 as measured by the principal exploration indicator, surface drilling. Data provided to DOE by the exploration companies indicated a total of 14.6 million meters (48 million feet) of drilling in 1978. In 1979, however, drilling declined to 12.5 million meters (41 million feet), and during 1980 the downward trend steepened with drilling estimated to be approximately 8.5 million meters (28 million feet) for the year (see Figure 9.4).

Annual gross additions to reserves, a measure of exploration success, have been at high levels for the higher cost, i.e., $13.60 to $22.65 per kilogram ($30 and $50 per pound) U_3O_8 categories, but have been decreasing for lower cost levels. Costs have increased significantly in recent years raising the quality of resources needed to produce at a given cost level and reducing the quantities available at that level. For example, in 1979 only 907 tonnes (1000 tons) were added to $6.80 ($15) cost revenues, but 47,164 tonnes (52,000 tons) were removed, largely because of inflation, and an additional 12,698 tonnes (14,000 tons) were depleted by production. Hence, in 1979, $6.80 ($15) reserves decreased from 263,030 to 204,075 tonnes (290,000 to 225,000 tons). This trend continued in 1980. On the other hand, in 1979 some 84,351 tonnes (93,000 tons) were added to $22.65 ($50) reserves and 69,839 tonnes (77,000 tons) removed for a net increase of 14,512 tonnes (16,000 tons) U_3O_8. Thus, while exploration has been successful, the costs of producing the resources found are high in comparison with current prices and concurrently the cost of producing previously found resources has also increased.

The sharp rise in exploration resulted from the increase in prices in the 1974 to 1976 period, the active procurement activity of utilities, and the optimistic projections of future growth in uranium demand. Many new companies became active in exploration. Over 150 companies were involved in exploration in 1979. Considering the drop in requirement projections the level of activity reached probably was in excess of real needs. Therefore, some reduction of effort more in line with future needs is not detrimental.

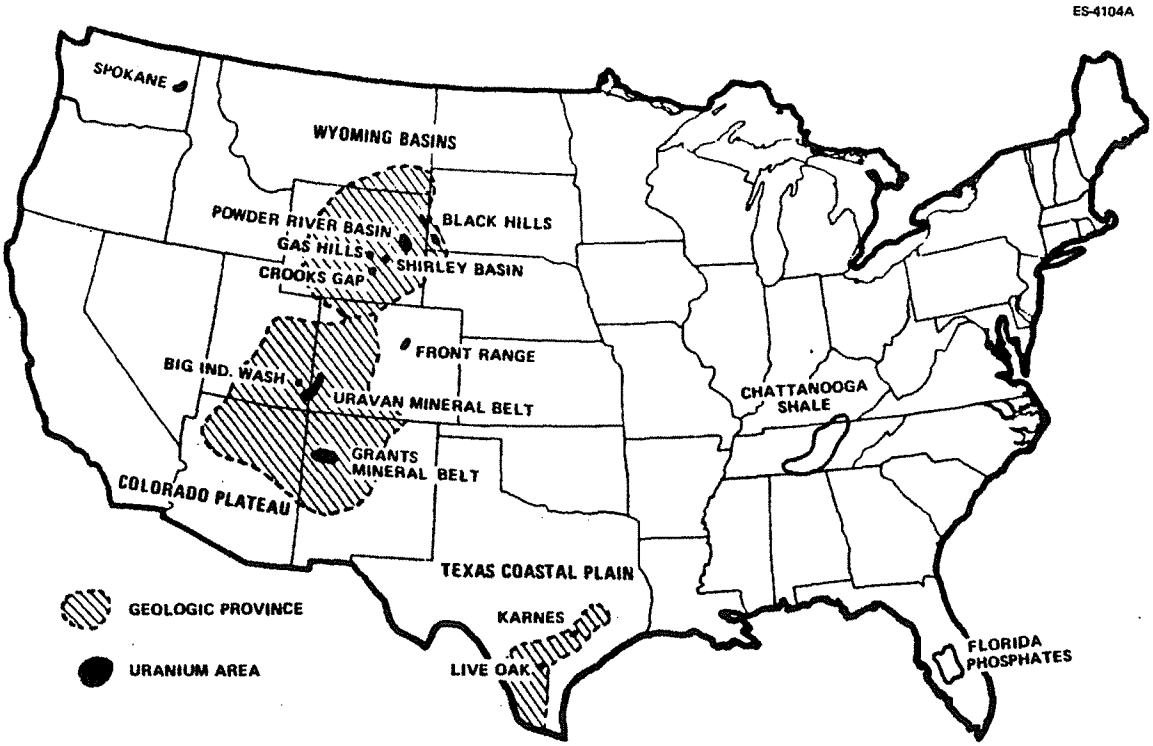

Fig. 9.3. Uranium areas of the United States.

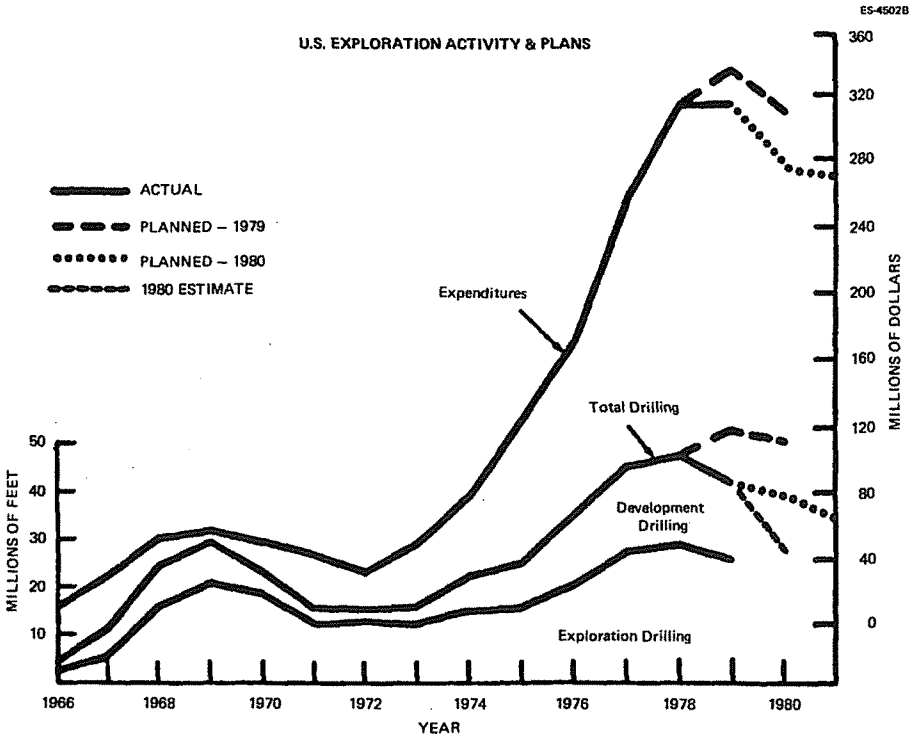

Fig. 9.4. U.S. exploration activity and plans. (To convert feet to meters, multiply by 0.3048.)

9.3.2.3 Domestic uranium production and capability

Domestic uranium production in 1980 was 19,573 tonnes (21,850 tons) U_3O_8 in concentrate. This represents a 15% increase over 1979 and is the highest U.S. production level for any single year. Production in recent months has been at record rates; the equivalent of over 19,954 tonnes (22,000 tons) U_3O_8 per year. This production comes from conventional mine-mill operations as well as nonconventional sources such as solution mining and byproduct recovery from processing of other minerals. The high production levels are in response to prior sales contracts. Buyers are actually receiving uranium in excess of their currently scheduled needs.

Several new uranium processing facilities are under construction or planned which could bring the total national capacity to around 27,000 tonnes (30,000 tons) per year by the mid-1980s.

Despite the increases in ore throughput and uranium production in 1980, a widespread curtailment of uranium mining and milling activities is underway. Production at some operating mines has been reduced and some planned mill expansions and construction are being postponed. The reduction in mine output will not be reflected in decreased uranium production until mine and mill ore stockpiles are reduced.

Studies have been conducted on attainable uranium production levels from uranium reserves in the United States and related costs. The uranium production capability projections should not be construed as being estimates of actual future supply, but simply as potential production which may be available to meet whatever demand eventually exists.

Using the "production center" concept, U.S. uranium production capability has been projected from ore reserves estimated as of January 1980, to be available at forward costs of $13.60 to $22.65 per kilogram ($30 and $50 per pound) U_3O_8 or less. The production centers consist of operating (Class 1), committed (Class 2), planned (Class 3) uranium extraction and processing facilities, and projected (Class 4) facilities based on probable potential resources. The study included conventional mills supplied by open pit and/or underground mines; solution mining and heap-leach operations; and operations where uranium is recovered as a byproduct of phosphate, copper, or beryllium mining and processing activities.

Projections are based primarily on operating conditions – average ore grades, mill recoveries, and operating and capital costs – similar to those currently prevalent in the uranium mining and milling industry. Specific information on company plans, costs, and operating methods has been considered.

Figure 9.5 shows the total projected production capability for $13.60 ($30) resources by resource category. Figure 9.6 shows the capability for $22.65 ($50) resources. Projected uranium demand and current sales commitments are also shown. Domestic demand is based on the DOE's Office of Uranium Resources and Enrichment 1980 nuclear power growth projections, assuming no reprocessing and a 0.20% U-235 enrichment tails assay.

9.3.2.4 Domestic reactor requirements

The outlook for uranium requirements is closely related to the growth of nuclear power. On December 1, 1980, there were 75 nuclear power reactors licensed to operate in the U.S., concentrated mostly in the East and Midwest. These plants have an electrical generating capacity of 55 Gigawatts (GWe). In addition to operating plants, there are under construction 86 plants with a total rated capacity of 95 GWe. Some of the plants are at such an early construction stage that they may be deferred or cancelled completely. An additional 17 reactors with 20 GWe capacity are on order. Together the group aggregates 170 GWe of capacity. However, the future for some of the ordered reactors is questionable.

Latest projections of nuclear power growth by the DOE's Office of Uranium Resources and Enrichment (URE) and the Energy Information Administration (EIA), Table 9.2, show an increase in nuclear power licensed to operate from 55 GWe at the end of 1980 to 96 GWe in 1985, 129 GWe in 1990, 155 GWe in 1995, and 180 GWe in 2000. EIA also projected a low case of 160 GWe and a high case of 200 GWe in 2000.

There are alternative views on U.S. power growth. The DOE's Office of Planning and Analysis has projected nuclear growth to the year 1990 at 125 GWe and to the year 2000 at 150 GWe, based on historic delays to nuclear power growth. The DOE Office of the Assistant Secretary of Nuclear Energy has projected 400 GWe, based on energy demand, growth, nuclear competitiveness, and industry construction capability. All of these values are sharply reduced from the projected growth of the nuclear industry of just a few years ago. For example, in 1976 U.S. nuclear capacity in the year 2000 had been projected to be 500 GWe, and in 1978 it had been projected to be 320 GWe.

ES-6733

ESTIMATED ANNUAL NEAR-TERM PRODUCTION CAPABILITY FROM RESOURCES AVAILABLE AT $30/LB U_3O_8 OR LESS WITH CLASS 1, 2, AND 3 EXPANSIONS AND CLASS 4

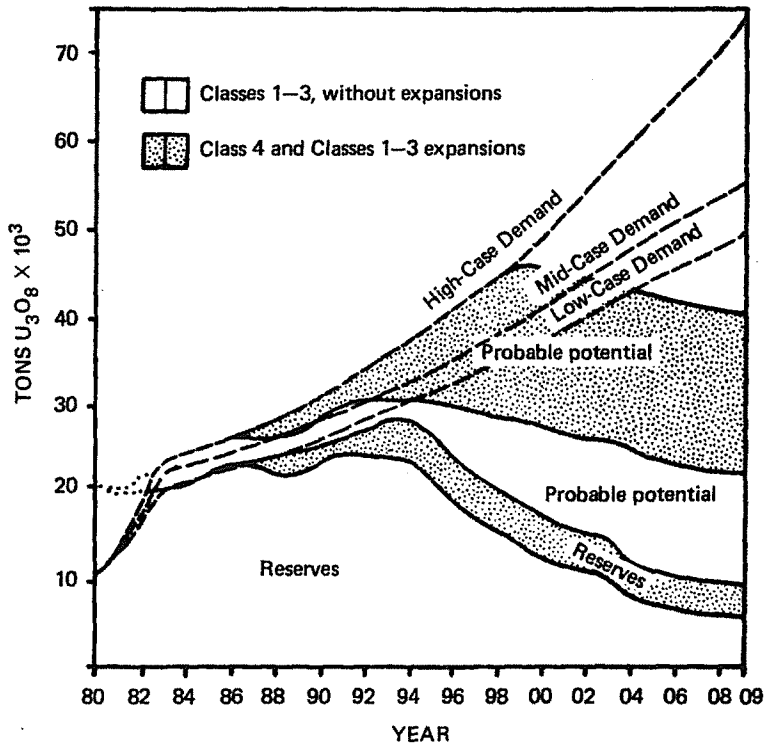

Fig. 9.5. Estimated annual near-term production capability from resources available at $13.60 per kilogram ($30 per pound) of U_3O_8 or less with Class 1, 2, and 3 expansions and Class 4. (To convert tons to tonnes, multiply by 0.907.)

Even at the more conservative estimates, nuclear capacity still is expected to expand substantially and to provide a significant portion of future domestic electric capacity. Current methods of projecting nuclear growth and uranium requirements are based on estimates of reactor startup dates considering construction and licensing times, and systems power requirements. Accurate forecasts have proven to be difficult.

The uranium needed to be delivered by uranium concentrate-producing plants as fuel for the nuclear plants will also increase over time; for the URE mid-case, from 12,063 tonnes (13,300 tons) U_3O_8 in 1981 to 21,405 (23,600) in 1985, 26,212 (28,900) in 1990, 31,745 tonnes (35,000 tons) in 1995, and 36,280 tonnes (40,000 tons) in 2000, if the enrichment plants are operated at 0.20% U-235 tails assay. Cumulative uranium requirements through the year 2000 range from 462,570 to 562,340 tonnes (510,000 to 620,000) tons U_3O_8 with 516,990 tonnes (570,000 tons) U_3O_8 for the mid-case.

Uranium requirements are based on normal lead times for fuel cycle steps and current technology for enrichment and for reactor design and operation. There are possible improvements in enrichment which would allow use of lower tails assays which would reduce uranium requirements. There are also possible improvements to reactor design and operation that could reduce uranium requirements. These factors are not likely to have a significant impact on uranium demands until at least well into the 1990s.

9.3.2.5 Uranium inventories

Buyers' inventories of uranium have been increasing for several years as actual deliveries have been in excess of needs. Inventories at the beginning of 1980 totalled 32,742 tonnes (36,100 tons) of natural uranium (Table 9.3), with 25,033 tonnes (27,600 tons) held by utilities. In 1980, U.S. utilities sent an

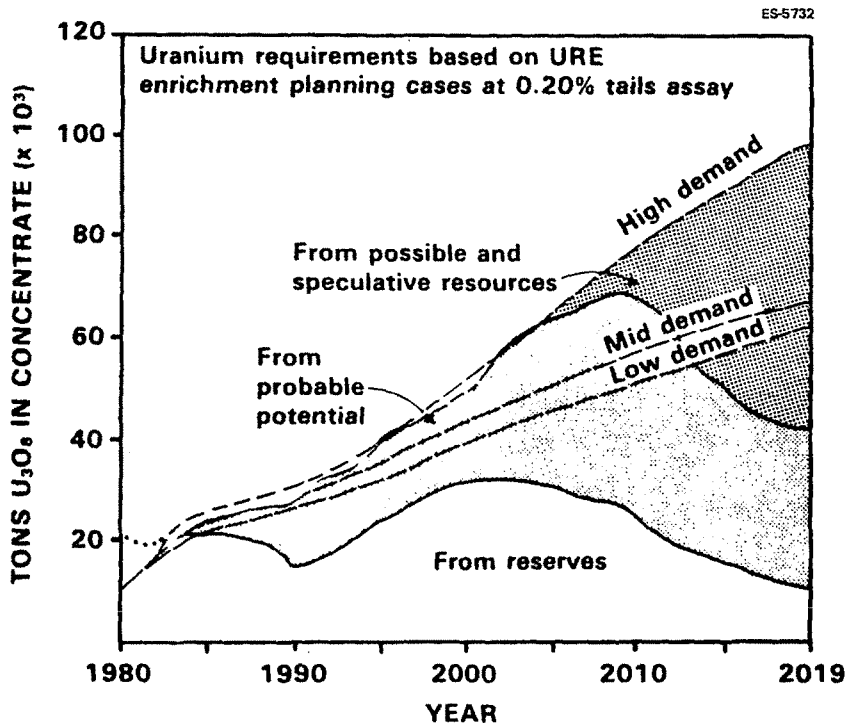

Fig. 9.6. Annual production capability from resources available at $22.65 per kilogram ($50 per pound) of U_3O_8 or less projected to meet nuclear power growth demand. (To convert tons to tonnes, multiply by 0.907.)

Table 9.2. U.S. nuclear power growth projections (June 1980)

End of year	Power Range [GW(e)]		
	Low	Mid	High
1985	85	96	105
1990	125	129	140
1995	142	155	165
2000	160	180	200

Table 9.3. Buyers' inventories of natural uranium (Tons U_3O_8)

Beginning of year	Domestic origin	Foreign origin	Total
1976	22,600	1,100	23,700
1977	25,800	3,500	29,300
1978	25,100	3,600	28,700
1979	28,000	5,200	33,200
1980	30,800	5,300	36,100

(To convert tons to tonnes, multiply by 0.907.)

equivalent of 15,691 tonnes (17,300 tons) U_3O_8 to the DOE gaseous diffusion plants for enrichment. Thus, the 25,033 tonnes (27,600 tons) inventory level amounted to 1.6 years of U.S. utilities' needs. Of those U.S. utilities who have responded to questions on inventory levels, most have indicated that they desire a level amounting to about one year's needs, although some have reported inventory levels as small as three month's needs, while others desire inventories as great as two year's needs. Producers also had inventories of about 2,177 tonnes (2,400 tons) U_3O_8 at the beginning of 1980, which is about a normal working inventory. The outlook is for a continuing buildup of buyers' inventories, as current contracted deliveries are in excess of actual needs.

9.3.2.6 Analysis of production capability and reactor capacity

Study of attainable production capability from currently estimated $13.60 ($30) U.S. ore reserves and probable potential resource, previously referenced, indicates that production levels of 40,815 tonnes (45,000 tons) U_3O_8 per year can be achieved with aggressive resource development and exploitation including both mining and milling. Although the level may be achieved by use of domestic $13.60 ($30) ore reserves and probable resources alone, development and utilization of $30 possible and speculative categories and use of $22.65 ($50) ore reserves and potential resources would provide added assurance that the levels could be attained and sustained. Considering the use of $22.65 ($50) resource, a level of 54,240 tonnes (60,000-tons)/year supply is achievable from currently estimated resources. Such a level could be reached by the early 1990s. Imported uranium and inventories would add to the supply from these projections.

The level of nuclear generating capacity supportable with 54,240 tonnes (60,000 tons)/year of uranium, will vary with enrichment tails assay and recycle assumptions. Without recycle of uranium or plutonium and with a 0.30% U-235 enrichment tails assay, about 260,000 MWe could be supported. Without recycle and at 0.20% tails assay, about 310,000 MWe could be supported. With recycle of uranium and plutonium and a 0.20% tails assay, about 520,000 MWe could be supported. All the levels of supportable capacity are above the 170,000 MWe of capacity in operation (55,000 MWe), under construction (95,000 MWe), and on order (20,000 MWe), as of late 1980. Thus, currently estimated resources can provide adequate uranium supplies for a sizable expansion to U.S. nuclear generating capacity.

The cumulative lifetime (30 years) uranium requirements for all of the above reactors (170,000 MWe) would be about .907 million tonnes (1.0 million tons) U_3O_8 at 0.20% enrichment tails with no recycle, compared to the 1.45 million tonnes (1.6 million tons) mean value in $13.60 (($30) or the 2.27 million tonnes at $22.65 (2.5 million tons at $50)) ore reserves, by-product, and probable potential resources. Evaluation of long-term fuel commitments on the basis of ore reserves and probable potential resources is considered a prudent course for planning. The lifetime commitment would be less than one-third of currently estimated $22.65 ($50) domestic resources, including the possible and speculative categories (see Table 9.1).

9.3.2.7 Uranium resource recovery

In regard to the availability of estimated uranium resources considering recoveries in mining and ore processing, estimates of U.S. uranium resources represent the quantity of uranium estimated to be minable expressed as tons of U_3O_8 of ore in the ground. These estimates are a reflection of the information available to DOE at the time of the estimate and thus are dependent on the extent of exploration. In view of the considerations involved in preparing the resource estimates and the uranium resource outlook, no adjustment for losses is warranted.

U.S. mining practice results in recovery of high percentages of the uranium contained in a deposit. DOE resource estimation procedures consider the capabilities and requirements of mining systems currently in use so that the estimates are a realistic appraisal of what is minable. Because deposits frequently are not fully delineated before they are developed, it is not unusual for more uranium to be recovered from deposits than was included in ore reserves before such deposits were put into production. Mining company practice seeks to recover as much of the contained mineral content as possible before abandoning a mine. A strong incentive for such practice is the increase in financial returns. In the processing of uranium ores, recoveries generally are over 90%. In 1980, mill recovery averaged about 93%. Higher recoveries are usually possible if economically justified.

9.3.2.8 High cost resources

An alternative to identification of additional low-cost resources is the utilization of higher cost resources. The highest cutoff cost category included in DOE resources in Table 9.1, is $45.30 per kilogram ($100 per pound) of U_3O_8. This level is an upper range of what might be of interest for utilization in light water reactors over the next few decades.

The increased price of oil and coal in the last few years has been a contributing factor to the increased price of uranium economically acceptable in light water reactors. This impact results from the relative insensitivity of nuclear electric power costs to increases in uranium prices. The cost of fuel is a very small fraction of the cost of power from a nuclear plant. In turn, the cost of natural uranium is only a small fraction of the fuel cost; enrichment, fabrication, reprocessing, and carrying charges make up the balance. As a result, large increases in uranium prices result in comparatively small increases in power costs. As pointed out in Section 9.3.2.6, nuclear capacity currently in operation, under construction, and on order, is expected to have adequate supplies of U_3O_8 at prices much lower than $45.30 per kilogram ($100 per pound) in 1980 dollars.

Knowledge of U.S. resources in the above $22.65 ($50) category is meager, largely because of the lack of past economic interest. There has been virtually no industry activity to search for or to develop such resources. Prospects for discovery of higher cost resources in the United States are considered promising at this stage of U.S. exploration. The principal large, very low-grade deposits that have been studied in some detail in the past are the shales and phosphates. The Chattanooga shale in Tennessee is of particular interest because of its large size. This deposit was extensively drilled, sampled, and studied in the 1950s. The higher grade part of the Chattanooga shale has an average uranium content of about 60 to 80 ppm compared to 1500 ppm in present-day ores. It contains in excess of 4.5 million tonnes (5 million tons) of U_3O_8 that may be producible at a cost of $45.30 or more per kilogram ($100 or more per pound) of U_3O_8. Additional work to develop production technology will be needed.

If Chattanooga shale were mined to fuel an 1150-MWe reactor, assuming recycle of uranium (but not of plutonium) and a 0.3% enrichment tail, about 11,428 tonnes (12,600 tons) of shale would have to be processed each day; with uranium and plutonium recycle (should that be practiced) and 0.20% enrichment tails, about 7,710 tonnes (8500 tons) per day would have to be processed. An average of about 10,250 tonnes (11,300 tons) of coal would have to be burned each day if 20 MJ/kg (8700 Btu/lb) of coal were used to produce power equivalent to that produced by a 1150-MWe reactor.

Utilization of the very low-grade resources such as Chattanooga shale would, of course, involve mining and processing very much larger quantities of ore than is currently mined to produce the same amount of uranium. From an environmental as well as from an economic point of view, identification and utilization of additional higher grade ores would be preferable. However, the shales are available if their use should become necessary.

9.3.2.9 Prices

During the period 1973-1979, the average delivery price per kilogram (pound) of U_3O_8 for sales from domestic producers to domestic buyers, in year-of-delivery dollars, increased from $3.22 to $10.80 ($7.10 to $23.85), as shown in Table 9.4.

Table 9.4. Historical trend of average uranium prices

(Dollars[a] per pound of U_3O_8)

Year	Final Price
1973	$ 7.10
1974	7.90
1975	10.50
1976	16.10
1977	19.75
1978	21.60
1979	23.85

[a]Year-of-delivery dollars.

(To convert dollars per pound to dollars per kilogram, multiply by 0.453.)

Future prices for material under contract as of July 1, 1980, as reported to DOE, is shown in Table 9.5. Also shown are the percentages of material under contract price arrangements covering the price data presented. The remainder is in market price contracts or in captive production.

9.3.2.10 Foreign uranium resource position

The most reliable source of information on world uranium resources is that compiled by the Working Party on Uranium Resources sponsored jointly by the Nuclear Energy Agency (NEA) and the International Atomic

Table 9.5. Average contract prices and settled market price contracts for uranium July 1, 1980

(Dollars[a] per pound of U_3O_8)

Year	Price	Percentages of procurement under contract price contracts
1980	26.00[b]	66
1981	28.70[b]	55
1982	34.80	47
1983	41.40	43
1984	43.45	35
1985	43.45	32
1986	46.85	16
1987	43.55	18
1988	42.70	22
1989	51.85	23
1990	53.25	16

[a] Year-of-delivery dollars.
[b] These years include settled market price contracts. Market price contract prices are determined sometime before delivery, based on prevailing market prices.

(To convert dollars per pound to dollars per kilogram, multiply by 0.453.)

Energy Agency (IAEA). This group has been gathering and publishing uranium resource estimates since 1965 and includes most of the significant uranium resource countries. In compiling its estimates this group classifies resources as Reasonably Assured resources (roughly comparable to ore reserves in the usual mining industry sense) and Estimated Additional resources (roughly comparable to DOE's probable potential resources). Resources in the world outside of the centrally planned economies area (WOCA) are tabulated by continents and major countries in Table 9.6.

Almost 80% of these resources are concentrated in three continents: North America, Africa, and Australia. Six countries within those continents - U.S., Canada, South Africa, Namibia, Niger, and Australia - have about three-quarters of the Reasonably Assured resources. This geographic concentration is a reflection of the geologic favorability of these areas as well as the extent of exploration and resource appraisal efforts to date.

9.3.2.11 Foreign production capacity and plans

Studies by the NEA and the IAEA have also provided reliable information on world production capacity. The current production capacity of existing non-U.S. plants (Class 1) is about 34,466 tonnes (38,000 tons) U_3O_8 annually, as shown in Table 9.7. This production is primarily in Canada, France, Namibia, Niger, and South Africa.

Construction of new plants (Class 2) with a capacity of about 7,256 additional tonnes (8,000 tons) is taking place, primarily in Australia and Canada. Plants that are planned (Class 3), could increase total annual production by another 32,652 tonnes (36,000 tons) U_3O_8 for a total of 76,188 tonnes (84,000 tons) U_3O_8 by 1990. Since needs for uranium are well below attainable production capacity levels, and prices would not justify all operations, it is likely that many of the projected plants will be built on a deferred schedule. It is also possible that some new plants will replace existing operations. Countries of particular significance in future production expansion are Australia and Canada, which have 82% of capacity under construction and 70% of the planned additional capacity.

9.3.2.12 Foreign reactor requirements

The uranium requirements in non-Communists foreign countries have been projected by the Energy Information Administration based on the reactors planned and timing of construction. Table 9.8 shows three cases of power plant growth which, by the year 2000, range from 300 GWe to 400 GWe of nuclear power in operation. The mid-case is taken as the most likely one. However, nuclear power growth projections have been subject to continual downward revision in the last several years.

Table 9.6. World uranium resources by continent[a]

(World outside centrally planned economies area)
(thousand tons U_3O_8)

	Reasonably assured		Estimated additional	
	$30/lb	$50/lb[b]	$30/lb	$50/lb[b]
North America				
U.S.	645	940	885	1,430
Canada	280	305	480	945
Other	9	44	44	65
Total	930	1,290	1,410	2,440
Africa				
South Africa	320	508	70	180
Niger	210	210	69	69
Namibia	152	173	39	69
Other	109	115	2	22
Total	790	1,000	180	340
Australia				
Total	380	390	165	180
Europe				
France	51	72	34	60
Spain	13	13	11	11
Sweden	1	390	0	4
Other	22	31	19	53
Total	90	510	60	130
Asia				
India	39	39	1	31
Other	13	21	0	0
Total	50	60	0	30
South America				
Brazil	96	96	117	117
Argentina	30	36	5	12
Other	0	0	7	8
Total	130	130	130	140
Worldwide total (rounded)	2,400	3,400	1,900	3,300

[a]Modified from "Uranium Resources, Production and Demand" OECD, Nuclear Energy Agency (NEA), and the International Atomic Energy Agency (IAEA), December 1979.
[b]Includes resources at $30 per pound of U_3O_8.

(To convert tons to tonnes, multiply by 0.907; to convert $ per pound to $ per kilogram, multiply by 0.453.)

In order to supply these nuclear plants, EIA has estimated the amount of uranium required assuming 0.20% U-235 enrichment plant tails and no recycle of uranium or plutonium. Table 9.8 gives the annual tons U_3O_8 from 1980 to 2000 for high-, mid-, and low-cases.

For the mid-case, foreign requirements increase from 16,689 tonnes (18,400 tons) U_3O_8 in 1980, to 23,763 tonnes (26,200 tons) U_3O_8 in 1985, and to 49,069 tonnes (54,100 tons) U_3O_8 in the year 2000. Cumulative requirements through the year 2000 total 650,319 tonnes (717,000 tons) U_3O_8.

If all the planned foreign mine-mill production came on-stream as currently projected, there would be considerable excess capacity. If only operating mills or those under construction were available by the late 1980s, production capacity would cover annual demands through the late 1990s.

Table 9.7. Foreign uranium production capability

(Thousand tons U_3O_8)

Year	Australia			Canada			France			Namibia			Niger			S. Africa			Other[b]			Foreign Total		
	1[a]	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
1980	1.3	0	0	9.8	0	0	4.5	0	0	5.3	0	0	5.2	0	0	8.3	0	0	4.1	0	0	38.5	0	0
1981	1.8	1.1	0	9.8	1.4	0	4.5	0.2	0	5.3	0	0	5.2	0	0	8.3	0	1.2	4.1	0	0.8	39.0	2.7	2.0
1982	1.8	3.3	0	9.8	1.9	0	4.5	0.5	0	5.3	0	0	5.2	0	0	8.3	0	2.9	4.1	0	3.0	39.0	5.7	5.9
1983	1.8	3.3	0	10.5	1.9	2.0	4.5	0.7	0	5.3	0	1.2	5.2	0	0	8.3	0	4.6	4.1	0	4.1	39.7	5.9	11.9
1984	1.8	3.3	0	11.0	2.9	4.0	4.5	0.7	0	5.3	0	1.2	5.2	0	0.7	8.3	0	5.2	4.1	0	4.4	40.2	6.9	15.5
1985	1.8	3.3	6.5	12.0	2.9	5.0	4.5	0.7	0	5.3	0	1.2	5.2	0	2.5	8.3	0	5.5	4.1	0	5.1	41.2	6.9	25.8
1986	1.2	3.3	11.5	12.0	2.9	7.2	4.5	1.4	0	5.3	0	1.2	5.2	0	5.2	8.3	0	5.6	4.1	0	5.1	40.6	7.6	35.8
1987	1.2	3.3	11.5	12.0	2.9	7.2	4.5	1.4	0	5.3	0	1.2	5.2	0	5.2	8.3	0	5.6	4.1	0	5.2	40.6	7.6	35.9
1988	1.2	3.3	11.5	12.0	2.9	7.2	4.5	1.4	0	5.3	0	1.2	5.2	0	5.2	8.3	0	5.5	4.1	0	5.3	40.6	7.6	35.9
1989	1.2	3.3	11.5	12.0	2.9	7.2	4.5	1.4	0	5.3	0	1.2	5.2	0	5.2	8.3	0	5.5	4.1	0	5.4	40.6	7.6	36.0
1990	1.2	3.3	11.5	12.0	2.9	7.2	4.5	1.4	0	5.3	0	1.2	5.2	0	5.2	8.3	0	5.2	4.1	0	5.5	40.6	7.6	35.8
Total																							84.0	

[a] Class: 1. Currently operating plants
2. Plants under construction
3. Planned plants

[b] Includes: Argentina, Brazil, CAR, Gabon, India, Italy, Mexico, Portugal, Spain, Yugoslavia. Based on "Uranium Resources, Production and Demand," December 1979.

(To convert tons to tonnes, multiply by 0.907.)

Table 9.8. Foreign nuclear capacity and uranium requirements

	Capacity [GW(e)]			Requirements (tons U_3O_8)[a]		
	Low	Mid	High	Low	Mid	High
1980	66	68	77	17,300	18,400	19,800
1985	117	124	128	24,000	26,200	29,200
1990	165	181	201	27,500	31,600	32,700
1995	229	252	280	34,600	41,500	47,800
2000	300	350	400	42,700	54,100	64,300

[a] 0.20% U-235 tails assay.

(To convert tons to tonnes, multiply by 0.907.)

Additional projections of WOCA nuclear growth and uranium requirements were developed during the International Nuclear Fuel Cycle Evaluation (INFCE). While the projections are now considered as high by many, they do provide an additional, more optimistic, viewpoint on future nuclear growth. The INFCE low case – modified to exclude the U.S. – indicated a growth in foreign (WOCA) nuclear capacity from 82 GWe at the end of 1980 to 217 GWe in 1990 and 580 GWe in the year 2000. Corresponding foreign uranium requirements would be 19,047 tonnes (21,000 tons) in 1980, 45,350 tonnes (50,000 tons) in 1990 and 108,840 tonnes (120,000 tons) in 2000. Such projections indicate a much larger possible growth in future uranium demands

9.3.2.13 Foreign competition and the domestic industry

The concentration of world uranium resources and production has, in past periods of low prices and ore production, fostered attempts to form cartel-like organizations seeking to restrict the free movement of uranium and influence pricing. The concentration of uranium production in a few countries will continue for some time, though there is an increasing diversity of supply sources. The opportunity for future foregin cartel-like activities will continue, particularly if uranium producer country governments are involved, which has been the case in the past. However, the severe criticism of such practice and the legal actions that have resulted in the United States might operate to discourage such activities in the future. Since the U.S. has the capability of producing a large portion – or all – of its uranium needs, and since the U.S. uranium buyers historically have shown a strong preference for domestic uranium, the U.S. is not expected to develop a large dependence on foreign uranium. These factors would tend to reduce the susceptibility of the U.S. to direct impacts of any cartel-like activity.

9.3.2.14 Conclusions

In conclusion, DOE assessment of uranium resources indicates that currently estimated ore reserves and probable potential resources at forward costs up to $13.60 per kilogram ($30 per pound) U_3O_8 total over 1.36 million tonnes (1.5 million tons), and at forward costs up to $22.65 per kilogram ($50 per pound) U_3O_8 total almost 2.17 million tonnes (2.4 million tons). The 2.17 million tonnes (2.4 million tons) U_3O_8 will support 390 GWe of nuclear power generating capacity, assuming a 30-year life for the reactors, no spent fuel reprocessing and an enrichment plant tails assay of 0.20% U-235. Under the latest DOE forecast for nuclear generating capacity in the post-2000 period, these resources should support U.S. nuclear power growth, including SONGS 2 and 3, well into the next century. However, meeting the uranium requirements for an expanding U.S. nuclear power industry will require extensive industry efforts to sustain exploration, and success in discovering and developing the potential uranium resources.

Foreign uranium resources are substantial and have been growing. Some of the more recently discovered deposits, especially in Canada and Australia, will have comparatively low-cost uranium production. The staff, therefore, concludes that there will be sufficient nuclear fuel available for SONGS 2 and 3.

9.4 DECOMMISSIONING

A license to operate a nuclear power plant is issued for a period of 40 years, beginning with the issuance of the construction permit. At the end of the 40-year period the operator of a nuclear power plant must renew the license for another time period or apply for termination of the license and for authority to dismantle the facility and dispose of its components.[8] If prior to the expiration of the operating license, technical, economic, or other factors are unfavorable to continued operation of the plant, the operator may elect to apply for license termination and dismantle authority at that time. In addition, at the time of applying for a license to operate a nuclear power plant, the applicant must show that he possesses "or has reasonable assurance of obtaining the funds necessary to cover the estimated costs of permanently shutting the facility down and maintaining it in a safe condition."[9] These activities, termination of operation and plant dismantling, are generally referred to as "decommissioning."

NRC regulations do not require the applicant to submit decommissioning plans at the time the construction permit and operating license are obtained; consequently, no definite plan for the decommissioning of the station has been developed. At the end of the station's useful lifetime, the applicant will prepare a proposed decommissioning plan for review by the Nuclear Regulatory Commission. The plan will comply with NRC rules and regulations then in effect.

The decommissioning of reactors is not new. Since 1960, five licensed nuclear plants, four demonstration nuclear power plants, six licensed test reactors, 28 licensed research, and 22 licensed critical facilities have been or are in the process of being decommissioned.[10] The primary methods of decommissioning consist of mothballing, entombing, dismantling, or a combination of these three alternatives. The primary methods are defined below in terms of the definitions provided in Regulatory Guide 1.86.[11]

Mothballing is the process of placing a facility in a nonoperating status. The reactor may be left intact except that all reactor fuel, radioactive fluids, and nonfixed radioactive wastes such as ion exchange resins, contaminated scrap materials, and contaminated chemicals are removed. The existing license is amended to a "possession only" status and continues in effect until residual radioactivity decays to levels acceptable for release to unrestricted access or until residual radioactivity is removed. The "possession only" license is a reactor facility license that permits a licensee to possess the facility but prohibits operation of the facility as a nuclear reactor.

Entombment consists of removing all fuel assemblies, radioactive fluids, and wastes followed by the sealing of remaining radioactive material within a structure integral with the biological shield or by some other method to prevent unauthorized access into radiation areas. A program of inspection, facility radiation surveys, and environmental sampling is required for a licensed facility that has been entombed.

Dismantling is defined as removal of all fuel, radioactive fluids and waste, and all radioactive structures. Surface contamination levels, established in Table 1 of Regulatory Guide 1.86, must be met prior to termination of the facility license. In addition to meeting the surface contamination levels, the acceptability of the presence of materials which have been made radioactive by neutron activation would be evaluated on a case-by-case basis prior to termination of the license. If the facility owner so desires, the remainder of the reactor facility may be dismantled and all vestiges removed and disposed of.

For a single nuclear reactor, the mothballing alternative costs about $2.45 million initially plus an annual maintenance and surveillance cost of $167,000. If a 24-hr manned security force is not required (e.g., a site with continuing operations), the annual cost could be reduced to $88,000. Translating these costs into unit cost of generating electricity, the 30-year levelized unit cost* would be about 0.04 mills/kWhr and if a manned security force is not required about 0.03 mills/kWhr.[12]

The entombing alternative costs about $7.58 million initially for a single unit facility plus an annual maintenance and surveillance cost of $58,000 for the duration of the entombment period.[13] These costs, when translated to a 30-year levelized unit cost* basis, amount to about 0.06 mills/kWhr.

The dismantling alternative for a single nuclear power reactor costs about $33.3 million to remove the radioactive structures associated with NRC requirements for terminating a possession only license.[12] An additional $4.8 million would be needed to remove the nonradioactive structures (cooling towers, administration buildings, etc.) to below grade.[13] There are no annual costs associated with this alternative. When the dismantling costs are translated to a 30-year levelized unit cost* basis, this amounts to about 0.17 mills/kWhr.

Combinations of mothballing and delayed (about 100 years) dismantling have 30-year levelized unit costs that are about the same as the mothballing alternative costs. Likewise, the costs for the entombing delayed dismantling combinations are about the same as the entombing cost. In both instances the annual maintenance cost for mothballing and entombing alternatives, on a present value basis, is sufficient to cover all the delayed dismantling cost for the mothballing alternative and about 80% for the entombing alternative.

Although the above costs are for a one-unit station, the savings associated with multiunit stations are small; thus, the unit cost (mills/kWhr) is essentially the same for a single unit station or multiunit station. For the San Onofre Nuclear Generating Station Units 2 and 3 the decommissioning costs would be about double that indicated for all of the decommissioning one-unit alternatives.

Studies of social and environmental effects of decommissioning large commercial power generating units have not identified any significant impacts.[13]

Also, studies indicate that occupational radiation doses can be controlled to levels comparable to occupational doses experienced with operating reactors through the use of appropriate work procedures, shielding, and remotely controlled equipment.[13]

The applicant may retain the site for power generation purposes indefinitely after the useful life of the station. The degree of dismantlement would be determined by an economic and environmental study involving the value of the land and crop value versus the complete demolition and removal of the complex. In any event, the operation will be controlled by rules and regulations in effect at the time to protect the health and safety of the public.

SONGS 2 and 3 are designed to operate for about 30 years, and the end of their useful life will occur approximately in the year 2011. The applicant has made no firm plans for decommissioning, but assumes that the following steps would be taken as minimum precautions for maintaining a safe condition:

1. All fuel would be removed from the facility and shipped offsite for disposition.

2. All radioactive wastes – solid, liquid, and gas – would be packaged and removed from the site insofar as practical.

A decision as to whether the station would be further dismantled would require an economic study involving the value of the land and scrap value versus the cost of complete demolition and removal of the complex. However, no additional work would be done unless it is in accordance with rules and regulations in effect at the time.

In addition to personnel required to guard and secure the station, concrete and steel would be used to prevent ingress into any building, particularly the radioactive areas.

Since the San Onofre site is located on U.S. Marine Corps property, the applicant must, if desired by the government, remove all of the improvements installed on the site at the end of the applicant's lease arrangement. This requirement could potentially entail complete removal and dismantling of the plant (ER, Section 5.8).

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*Based on a 1200-MWe generating unit beginning operation in 1958, a capacity factor of 60%, an escalation rate of 5%, and a discount rate of 10%. A more complete analysis of decommissioning costs can be found in Appendix B of NUREG-0480.[6]

REFERENCES

Unless otherwise noted, documents are available in public technical libraries.

1. U.S. Department of the Interior, Bureau of Mines, "Mineral Facts and Problems," 1970, p. 230.

2. U.S. Atomic Energy Commission, "Uranium Industry Seminar," Grand Junction, Colorado, Office, Report GJO-108(74), October 1974.***

3. Energy Research and Development Administration, "Survey of U.S. Uranium Marketing Activity," Report ERDA 77-46, May 1977.***

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5. U.S. Nuclear Regulatory Commission, "Final Generic Environmental Statement on the Use of Recycle Plutonium in Mixed Oxide Fuel in Light Water Cooled Reactors," Report NUREG-0002, vol. 4, U.S. Government Printing Office, Washington, D.C., August, 1976, Table XI-32, Section 4.**

6. U.S. Nuclear Regulatory Commission "Coal Vs. Nuclear: A Comparison of the Cost of Generating Baseload Electricity by Region," NUREG-0480, December 1978.**

7. U.S. Atomic Energy Commission, Press Release, No. T-517, Oct. 25, 1974.*

8. Title 10, "Rules and Regulations," Code of Federal Regulations, Part 50, "Licensing of Production and Utilization Facilities," Section 50.51, "Applications for Termination of Licenses."

9. Title 10, "Rules and Regulations," Code of Federal Regulations, Part 50, "Licensing of Production and Utilization Facilities, Section 50.33, "Content of Applications; General Information."

10. P. B. Erickson and G. Lear, "Decommissioning and Decontamination of Licensed Reactor Facilities and Demonstration Nuclear Power Plants," presented at Conference on Decontamination and Decommissioning in Idaho Falls, Idaho, Aug. 19-21, 1975.*

11. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.86, "Termination of Operating Licenses for Nuclear Reactors."

12. U.S. Nuclear Regulatory Commission, "Draft Generic Environmental Statement on Decommissioning of Nuclear Facilities," USNRC Report NUREG-0586, January 1981.

13. Atomic Industrial Forum, Inc., "An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives," Report AIF/NESP-009.

* Available for inspection and copying for a fee in the NRC Public Document Room, 1717 H Street, N.W. Washington, D.C. 20555.

** Available from NRC/GPO Sales Program, Washington, D.C. 20555, and the National Technical Information Service, Springfield, VA 22161.

*** Available from NTIS only.

10. BENEFIT-COST SUMMARY

10.1 RÉSUMÉ

There have been minor changes in the benefit-cost analysis of station operation since the issuance of the FES-CP in March 1973. The most significant changes are that the staff has revised the economic cost estimates upwards to reflect the rapid escalation seen during the last few years and has included among the benefits of station operation the fuel oil savings that will be made possible by having additional non-oil-fired, base-load capacity available in the California Power Pool. There have been essentially no significant changes in the staff's assessment of the environmental costs of operating SONGS 2 & 3; however, a broadening of the review process has occurred and is reflected in Table 10.1.

10.2 BENEFITS

The primary benefits of station operation will be the 9.3 to 13.0 billion kWhr of electricity produced by the two additional units each year (assuming a range of capacity factors of 50 to 70%), the increase in the reliability of electric service resulting from the addition of 2114 MWe of generating capacity, and an estimated regional decrease in the consumption of fuel oil of 13.2 million to 18.5 million barrels of oil per year (again assuming a range of capacity factors of 50 to 70%).

The staff also notes that operation of SONGS 2 & 3 will result in the generation of local revenues through property taxes and state sales and use taxes (annual property taxes will be approximately $13 million while state sales and use taxes resulting from station operation are estimated to be $3 million per year) and will increase local employment (over 300 new jobs will be directly created, with the average income of station workers being approximately $30,000 per year in 1980 dollars). However, these considerations are not included in the staff's benefit-cost analysis because from a societal viewpoint these local benefits are in actuality transfer payments from those using the electricity generated by the station to the recipients of the tax and employment benefits.

10.3 ECONOMIC COSTS

Since the issuance of the FES-CP the fuel, operating, and maintenance costs of nuclear plant operation have escalated more rapidly than anticipated by the staff in 1973. Based on more recent information, the staff now estimates the 1983 costs of station operation to be as follows: fuel costs — $120 million per year; operating and maintenance costs — $45 million per year; and decommissioning costs — $2.7 million per year.

10.4 ENVIRONMENTAL COSTS

Since the issuance of the FES-CP the applicants have accumulated additional environmental data and have made modifications in the station design. The staff, on making a reassessment of the environmental costs of station operation based on this new information, has found that the conclusions reached in the FES-CP are still valid. Table 10.1 summarizes the staff's assessment of the environmental impacts of station operation.

10.5 SOCIAL COSTS

The restriction in public use of 1.4 km (0.85 mile) of the San Onofre Beach is a significant cost of operation of the station. The number of personnel needed to operate SONGS 2 & 3 is a small fraction of the expected population growth in the communities near the station. As a result, the extra cost of providing public services to station personnel who relocate in the area is not likely to be discernible in these communities.

Table 10.1. Benefit-cost summary for the operation of SONGS 2 & 3[a]

Primary impact and population or resource affected	Unit of measure	Magnitude of impact
DIRECT BENEFITS		
ENERGY (50–70% capacity factor)	kWhr/yr X 10^6	9,300–13,000
CAPACITY	kW X 10^3	2,114
REDUCED FUEL OIL CONSUMPTION (50–70% capacity factor)	bbl/yr X 10^6	13.2–18.5
ECONOMIC COSTS		
OPERATING (1980 dollars, 60% capacity factor)		
Fuel	$/year	120,000,000
Operation and maintenance	$/year	45,000,000
DECOMMISSIONING (annualized value)	$/year	1,100,000
ENVIRONMENTAL COSTS		
IMPACT ON LAND		
Land use		Insignificant
Terrestrial ecology		Negligible
IMPACT ON WATER		
Fresh water consumption	gal/day	1,066,000
Salt water consumption		Insignificant
Heat discharge to natural water body		
Aquatic biota		Insignificant
Migratory fish		Insignificant
Chemical discharge to natural water body		
People		Not discernible
Aquatic biota		Not discernible
Water quality		Not discernible
Radionuclide contamination of natural surface water body		
All except tritium	Ci/year/unit	1.1
Tritium	Ci/year/unit	300
Chemical contamination of groundwater		
People		Not discernible
Plants		Not discernible
Radionuclide contamination of groundwater		
People		Not discernible
Plants and animals		Not discernible
Effects on natural water body of condenser cooling system operation		
Primary producers and consumers		Small
Fisheries		Small
Natural water drainage		
Flood control		No damage
Erosion control		Insignificant
IMPACT ON AIR		
Chemical discharge to ambient air		
Air quality, chemical		Negligible
Air quality, odor		Negligible
Radionuclides discharged to ambient air		
Noble gases	Ci/year/unit	8,800
Radioiodines	Ci/year/unit	0.195
Carbon-14	Ci/year/unit	8
Argon-41	Ci/year/unit	25
Tritium	Ci/year/unit	1,100
Particulates	Ci/year/unit	0.34
Fogging and icing		None
TOTAL BODY DOSES TO U.S. POPULATION		
General public, unrestricted area	Man-rem/year	442
SOCIETAL COSTS		
OPERATIONAL FUEL DISPOSITION		
Fuel transport (new)	Trucks per year	11
Fuel storage		In-building storage
Waste products (spent fuel)	Trucks per year	200
PLANT LABOR FORCE		Insignificant

[a]See Appendix C for calculations and explanations of table entries.

(To convert gal to liters, multiply by 3.7.)

10.6 ENVIRONMENTAL COSTS OF THE URANIUM FUEL CYCLE AND TRANSPORTATION

The staff has evaluated the environmental impacts of the uranium fuel cycle as presented in Table 5.8 and has found these impacts to be sufficiently small so that when superimposed upon the other environmental impacts assessed against the operation of the station, they do not alter the overall benefit-cost balance.

10.7 SUMMARY OF BENEFIT-COST

As the result of this second review of potential environmental, economic, and social impacts, the staff has been able to forecast more accurately the effects of station operation. The higher economic costs identified by the staff would not alter the staff's previous conclusion as to the overall balancing of the benefits of the station versus the environmental costs, whereas the benefit from the reduction in the regional consumption of fuel oil is felt to add significantly to the total benefits of station operation. Additional environmental costs have been identified as: (1) removal of approximately 1.4 km (0.85 mile) of beach from unrestricted public use, (2) possible destruction of at least a portion of the San Onofre Kelp Bed during the summer months by the heated water discharge, (3) occupation of about 7.2 ha (17.8 acres) of land by new towers, access roads, and switchyards associated with new transmission facilities, (4) environmental effects of the uranium fuel cycle as enumerated in Table 5.8, and (5) environmental impacts of transportation of fuel and waste to and from nuclear power plants as indicated in Table 5.7. Consideration of these additional costs together with those identified in the FES-CP does not alter the position taken in the FES-CP that the environmental and social costs are acceptable and that these costs are outweighed by the primary benefits of operating SONGS 2 & 3.

11. DISCUSSION OF COMMENTS RECEIVED ON THE DRAFT ENVIRONMENTAL STATEMENT

Pursuant to 10 CFR Part 51, the Draft Environmental Statment and a supplement to the Draft Environmental Statement related to the operation of the San Onofre Nuclear Generating Station, Units 1 and 2, were transmitted, with a request for comments, to:

Department of Agriculture

Department of Army (Corps of Engineers)

Department of Commerce

Department of Energy

Department of the Interior

Department of Health, Education, and Welfare

Department of Housing and Urban Development

Department of Transportation

Environmental Protection Agency

Federal Energy Regulatory Commission

Advisory Council on Historic Preservation

California Department of Health (Water Pollution Control Commission, Air Pollution Control Commission, Occupational Health Office)

California Department of Natural Resources

California Department of Parks and Recreation

In addition, the NRC requested comments on the Draft Environmental Statement and its supplement from interested persons by a notice published in the Federal Register on December 6, 1978 (43 FR 25183) and January 13, 1981 (46 FR 7435), respectively. In response to the request referred to above, comments were received from:

Draft Environmental Statement

U.S. Department of Agriculture, Science and Education Administration (DASEA)
U.S. Department of Agriculture, Economics, Statistics and Cooperative Services (DAESC)
U.S. Department of Agriculture, Soil Conservation Service (DASCS)
Department of Housing and Urban Development (HUD)
Department of the Army, Corps of Engineers (COE)
Federal Energy Regulatory Commission (FERC)
U.S. Department of the Interior (DOI)
Rourke and Woodruff Law Offices (RWL)
U.S. Department of Commerce (DOC)
Department of Health, Education, and Welfare (HEW)
Southern California Edison Company (SCE)
U.S. Environmental Protection Agency (EPA)
Mr. Marvin I. Lewis (MIL)
Richard J. Wharton (RJW)

Supplement to the Draft Environmental Statement

U.S. Dearptment of Agriculture, Economics, Statistics and Cooperative Services (DAESC)
Federal Energy Regulatory Commission (FERC)
U.S. Department of the Interior (DOI)
U.S. Environmental Protection Agency (EPA)
Union of Concerned Scientists (UCS)
Richard J. Wharton (RJW)
Southern California Edison Company (SCE)
Frank H. Grundel (FHG)
San Diego Association of Governments (SAG)
U.S. Department of Agriculture, Soil Conservation Service (DASCS)

The comments are reproduced in this statement as Appendix A. The staff's consideration of the comments received and its disposition of the issues involved are reflected in part by changes in the text in the pertinent sections of this Final Environmental Statement and in part by the discussion in Section 11. The comments are categorized by subject and are referenced by the use of the abbreviations indicated above. The pages in Appendix A on which copies of the respective comments appear are indicated by each subject title relating to the comment, and in the index to Appendix A.

11.1 EROSION CONTROL (DASCS, A-4)

The applicant's erosion control plans are briefly discussed and referenced in Sections 6.2.2 and 6.3.2. In addition, the treatment of disturbed areas is addressed in the FES-CP. Such discussions are beyond the scope of the OL review.

11.2 LOSS OF PRIME LANDS (DASCS, A-4)

The discussion of prime lands lost to access roads and transmission towers, which is presented in Appendix E of the DES, is based on available information as a result of staff discussions with Mr. Jack Smith and Mr. Ted Thee of the Soil Conservation Service (SCS) Escondido Field Station and Mr. Jon Christianson of the SCS Tustin Field Office.

11.3 RECREATION RESOURCES (DOI, A-5; RJW, A-48)

The original plan to allow recreational use in the beach area immediately adjacent to the nuclear plant was altered in the course of hearings before the ASLB and ASLAB based on safety considerations. The staff reasserts its judgment that, while significant, the impact of beach closure is not sufficient to warrant denying the applicant an Operating License for SONGS 2 & 3. While the 1.4 km (0.85 mile) of beach to be closed must be considered a valuable recreational resource, there are approximately 5.6 km (3.5 miles) of State Beach immediately south of this area and almost 1.1 km (0.7 miles) immediately north which remain open to the public. Of those three parcels of beach, the one to be closed gets substantially less use than the other two and is directly adjacent to the SONGS complex, where the natural aesthetics of the area have been altered by plant development. Finally, while the 30 years of beach closure is clearly a long time, it does not represent an "irreversible and irretrievable commitment of resources" as the intervenors contend. For these reasons, it is the judgment of the staff that the closure of this stretch of beach, while significant, is not sufficiently adverse to warrant forbidding plant operations.

11.4 RADIOLOGICAL IMPACTS (HEW, A-10; SCS, A-30; EPA, A-40/A-42; MIL, A-45; RJW, A-50)

The NRC staff agrees it is appropriate to note that dose commitments to any individual will also meet EPA regulation 40 CFR 190 which requires that such doses will not exceed 25 mrem/year to any individual.

The recent AIF study* referred to in this comment was an effort to provide the potential impact of lowering the exposure limit to 500 millirems per year. The data were developed to fit the model that the AIF developed to evaluate the impact of the exposure limit reduction. The exposure data were meant to portray the <u>type</u> of exposure situations which occur at PWR's but are not likely to occur every year at each plant. (See Section 5.5.1.4 for staff consideration of occupational radiation exposures.)

Table 5.8 is based on NRC Table S-3, from 10 CFR Part 51, and is a generic discussion of impacts for the balance of the uranium fuel cycle. The staff is bound by the Commission standard as shown in Table 5.8. A discussion of alternative handling of HLW or TRU wastes is therefore inappropriate for considerations of licensing SONGS 1 & 2.

*"A Preliminary Assessment of the Potential Impacts on Operating Nuclear Power Plants at a 500 millirem per Year Occupational Exposure Limit," J. Vance, C. Weaver, E. Lepper, AIF, April 1978 (unpublished).

The staff has made its own independent and reasonably conservative estimates of potential doses to maximum individuals as a result of the operation of SONGS 2 & 3. Considering the uncertainties involved in such calculations, the staff finds a factor of 3 difference to be in very good agreement. Therefore, the staff rejects the request that Table 5.4 of the DES be revised in order to be consistent with applicant's estimated doses.

The staff calculation was for sport fish taken in the mixing zone, not 0-10 miles from the outfall, and is an independent and a reasonably conservative estimate of doses to a maximum individual. It is true that doses would be much less at greater distances from the outfall. However, the staff rejects the suggestion that Tables 5.6 (and 5.2 and 5.3) are in need of revision in order to be consistent with the applicant's estimates, particularly when both sets of estimates are orders of magnitude below the Appendix I design objective doses.

The staff agrees that the DES contains relatively little information regarding beach use at the SONGS site. Detailed discussion is presented in the Applicant's ER (e.g., pp. 2.1-4 to 2.1-7, and 5.2-1 through 5.2-54). In addition, more information regarding the staff conclusions and assumptions relating to doses to transient populations at the beach is presented in response to EPA comments.

The dose to individual users of the beach was not calculated for the following reasons:

1. The prevailing wind direction generally carries radioactive effluents away from the beach, thereby lowering potential exposures.

2. The beach is part of the exclusion area of the plant site, and public use (e.g., sunbathing and picnicking) is not permitted (e.g., see p. 2.105 of the applicant's ER).

3. The walkway connecting the south and north beaches is at the bottom of a 28-ft seawall which effectively shields passerbys from any direct radiation from the plant.

4. Although the dose rates at the site boundaries are expected to be low, annual doses to individuals would be even lower due to limited exposure times in transit between beaches.

Doses to individuals at the visitor center (0.1 mi E) were calculated, but occupancy factors result in much lower annual doses than calculated from permanent residents assumed living year-around at the WNW site boundary (0.36 mi) reported in the DES. As noted in Section 5.5.1.4, direct radiation (other than from the gaseous plume) from SONGS 2 & 3 is expected to be very low at the beach area. When coupled with limited exposure periods for transients, and shielding from the 28-ft-high seawall, the potential annual doses would be insignificant.

Population doses included transient populations by sector within 10 miles of the site. Transient populations were added to the projected resident populations for the year 2000 by assuming each transient spent one full day (24 hours) visiting during each year.

10 CFR Part 20 (10 CFR 20.105a) has been modified to include the provisions of 40 CFR Part 190. Also, the SONGS 2 & 3 technical specifications will require a demonstration to show compliance with 40 CFR Part 190 considering the operation of three reactors at the SONGS site.

Section 5.5.3 of the FES has been modified to include the long-term environmental effects associated with carbon-14, krypton-85, and tritium releases of the fuel cycle excluding the reactor releases. These modifications were added to the earlier discussion which focused largely on the radon-222 impacts.

Staff estimates of the longer term effects of carbon-14, tritium, krypton-38, and releases of the reactor contribute less than 30% of the total fuel cycle impacts presented in Section 5.5.3 of the FES. Health effects reported in the FES on a "per reactor year" basis can be multiplied by the reactor operating time (i.e., 30 years) to obtain the total or integrated estimate.

Nevertheless, the staff is in the process of modifying its calculation methodology to automatically consider the radiological impacts of effluent releases of the entire nuclear fuel cycle.

It is important to note that the FES results conservatively include the impacts of both uranium and plutonium recycle even though such operations are not currently permitted. Thus, the FES results are conservative for any recycle option, especially the "throw-away" cycle, the option currently allowed.

The NRC staff has reevaluated the proposed preoperational radiological environmental monitoring program for SONGS 2 and 3. The proposed program is based on the existing SONGS 1 operational program. That program will be revised in the near future to meet the Appendix I (10 CFR Part 50) requirements now being incorporated into the Environmental Technical Specifications for Unit 1, thereby updating the preoperational program for Units 2 and 3.

Response to specific EPA comments are as follows:

1. Current NRC criteria require collection and measurement of I-131 only, since it is the radioiodine which accounts for essentially all of the radioiodine environmental dose commitment (nearly all of which is through food pathways). The reason the applicant specified a maximum of 8 days was to be certain that the samples can be collected, transported to a laboratory (often at a considerable distance), and analyzed "within 8 days" under difficult circumstances (e.g., storms, trucking strikes, etc.). In most cases the elapsed time will be much less.

2. The intent of the air sampling program is to monitor continuously at all sites. However, experience has shown that occasionally air sampling equipment fails during a 7-day period, and the samples are of no value. The same experience indicates the applicant can almost always achieve 75-80% reliability.

   That is the only reason for mention of "a minimum of 10 samples per quarter" by the applicant.

3. The staff agrees that it might be desirable to have a TLD station along the walkway below the seawall. However, as noted in response to the previous comment, the walkway is 28 ft below the top of the seawall and there is no line-of-sight between the beach and any radiation sources on the site. The beach in front of the site is part of the exclusion area (i.e., no sunbathing, picnicking, etc. is permitted). Therefore, there is no possibility of any member of the public receiving a measurable radiation dose since individual exposure times would be very small.

4. The NRC has included U.S. population dose commitment estimates in Section 5.5 for a few years (see, for example, Table 5.5). In addition, the staff has been including discussion of the Rn-222 question since mid-1978 (see Section 5.5.3).

Table 5-8 says Rn-222 releases are "Presently under reconsideration by the Commission," and in footnote a, "These issues which are not addressed at by this table may be subject to litigation in individual licensing proceedings." The results of generic testimony by the staff at other hearings is summarized briefly on pp. 5-36 to 5-40. Contrary to Mr. Lewis' assertion, NEPA does not require quantification of the impacts of Rn-222 releases over the "full period of toxicity" (presumably he is referring to Th-230, the parent of Rn-222). The staff feels the conservative evaluation in Section 5.5.3 probably accounts for the releases and potential doses resulting from Rn-222 releases over periods of many millenia. In addition, the FES will provide a revised Section 5.5.3 which also includes potential impacts of C-14 over periods up to 1,000 years into the future.

The staff agrees that stabilization of surface tailings piles cannot be assured "forever." However, numerous options, including deep burial in worked-out open pit mines or underground mines, are being voluntarily used by some applicants and may be used increasingly in the future by others. It should be noted that if such tailings are exposed by acts of God (e.g., glaciation), the potential long-term impacts could be lower than for the natural uranium ore since milling will remove over 90% of the U-235 (the parent of Th-230).

Environmental releases from "nuclear waste materials, including the interim storage of spent fuel, on site" are so small relative to normal operational releases as to be inconsequential. Such releases and potential impacts have been estimated* and do not significantly change the estimated impacts presented in the DES for normal operations. In that sense, the releases have been included in the DES assessment of environmental impacts.

11.5 METEOROLOGY (SCE, A-16)

The onshore tracer test results indicated that measured ground-level centerline one-hour average concentrations were less than concentrations estimated from the usual staff calculations. But a reduction for annual average values would not be the same.

*Draft Generic Environmental Impact Statement on "Handling and Storage of Spent Light Water Power Reactor Fuel," NUREG-0404, U.S. Nuclear Regulatory Commission (March 1978).

Over a long period of time, such as a year, the wind direction within a sector should be randomly distributed, and thus the path of the plume should be randomly distributed. The time that any part of the plume is over a point within the sector contributes to the annual average at that point. This time integration and random path of plume have the net effect of uniformly distributing an effluent horizontally within a sector. Any enhanced dispersion due to additional horizontal plume spreading would not reduce the annual average concentration. In the staff calculations it was assumed that the effluent was uniformly distributed horizontally over the sector.

The ground-level annual average concentration would be dependent on the wind frequency and on the vertical distribution of the effluent within the plume. No direct measurements of vertical plume distributions were made during these onshore tests or the tests referenced in NUS-1927. Without a more definitive description of the vertical distribution of the plume, it has been the staff position not to adjust annual average dispersion estimates.

11.6 THERMAL ANALYSIS (SCE, A-20/A-21)

The air temperatures used by the staff in its thermal model are too high and, therefore, the staff's ambient temperature predictions are too high. However, nonlinear effects of the air temperature on the water temperature are negligible so that the staff's excess temperature predictions are correct despite the systematically high ambient air temperatures used in the mathematical model.

Higher near-shore predicted ambient water temperatures appear as a result of the depth-averaged format of the predictions. The near-shore region is shallow, resulting in near homogeneous vertical temperature structure. In deeper water, strong stratification is present so that the depth-averaged water temperatures are lower due to the presence of cool bottom water. The staff's actual ambient surface temperature predictions show no variation in the offshore direction. Ambient temperatures based on field measurement have been used in Section 5.4 of the FES.

A brief discussion of the applicant's error analysis is given in Section 5.3.1.1 of the FES.

Errors in the staff's mathematical model can be introduced in several ways. First consider the accuracy of the numerical method. The TEMPTWO algorithm is consistent and stable. The use of direct upwind differencing can produce numerical dispersion when the Courant Number is not equal to 1. To minimize this error, the staff used a time-step that produced a Courant No. of 1 near the diffusers. This essentially eliminated numerical dispersion error around the discharge areas. Far from the discharges, numerical dispersion exists; however, this makes the predictions less conservative. To correct for this, the staff could raise the predicted excess temperatures in the far field. The staff believes that inaccuracies due to numerical dispersion are slight and, therefore, corrections of such inaccuracies are unnecessary.

Errors could also have been introduced through the methods used to represent turbulent transport and surface heat transfer. In developing the model, an effort was made to incorporate formulations which are universal; that is, to create a model that requires no adjustment of coefficients on a site-specific basis. The TEMPTWO model has been applied to other plants and results have compared favorably with available data. Thermal predictions for the Peach Bottom Plant and the Anclote Plant, including comparison with field data, are shown in Figures 11.1 through 11.8. The Peach Bottom Plant is on an impoundment of a river in Pennsylvania and the Anclote Plant is located on the Gulf of Mexico. The success of the TEMPTWO model at two quite different sites indicates that the submodels for turbulent transport and surface heat transfer can confidently be applied to San Onofre.

The staff's model did not include plant-induced densimetric flows. The staff performed a scale analysis and determined this effect to be insignificant at the San Onofre site.

Individual jet mixing is not calculated within the staff's model. However, this effect was included based on the applicant's near-field results.

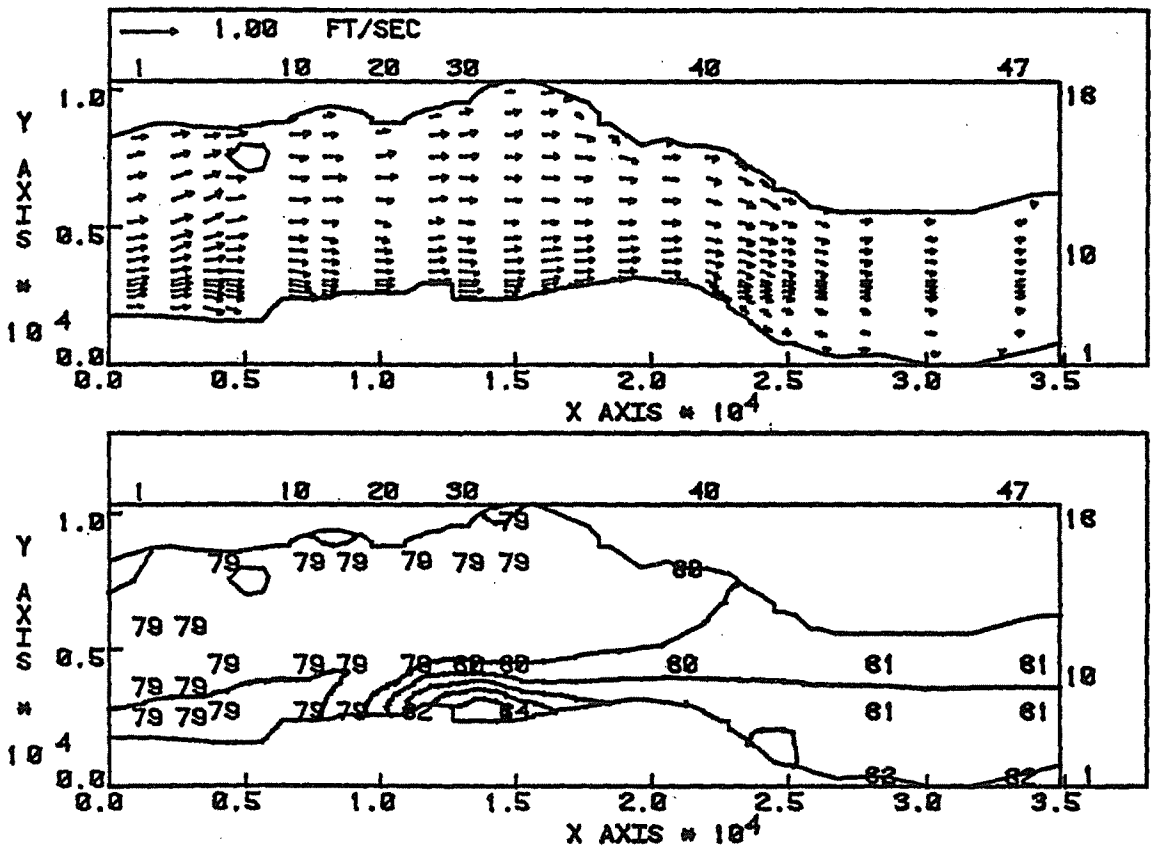

Figure 11.1 Computer simulation results for the two-dimensional depth-averaged (with self-similar vertical variation) flow conditions and temperature conditions (isotherms with 1°F gradation (1/1.8°C) in the Conowingo Pond Reservoir in the vicinity of the Peach Bottom Atomic Power Station at 9 a.m. on July 18, 1974, during reservoir conditions: downstream low flow after slack water.

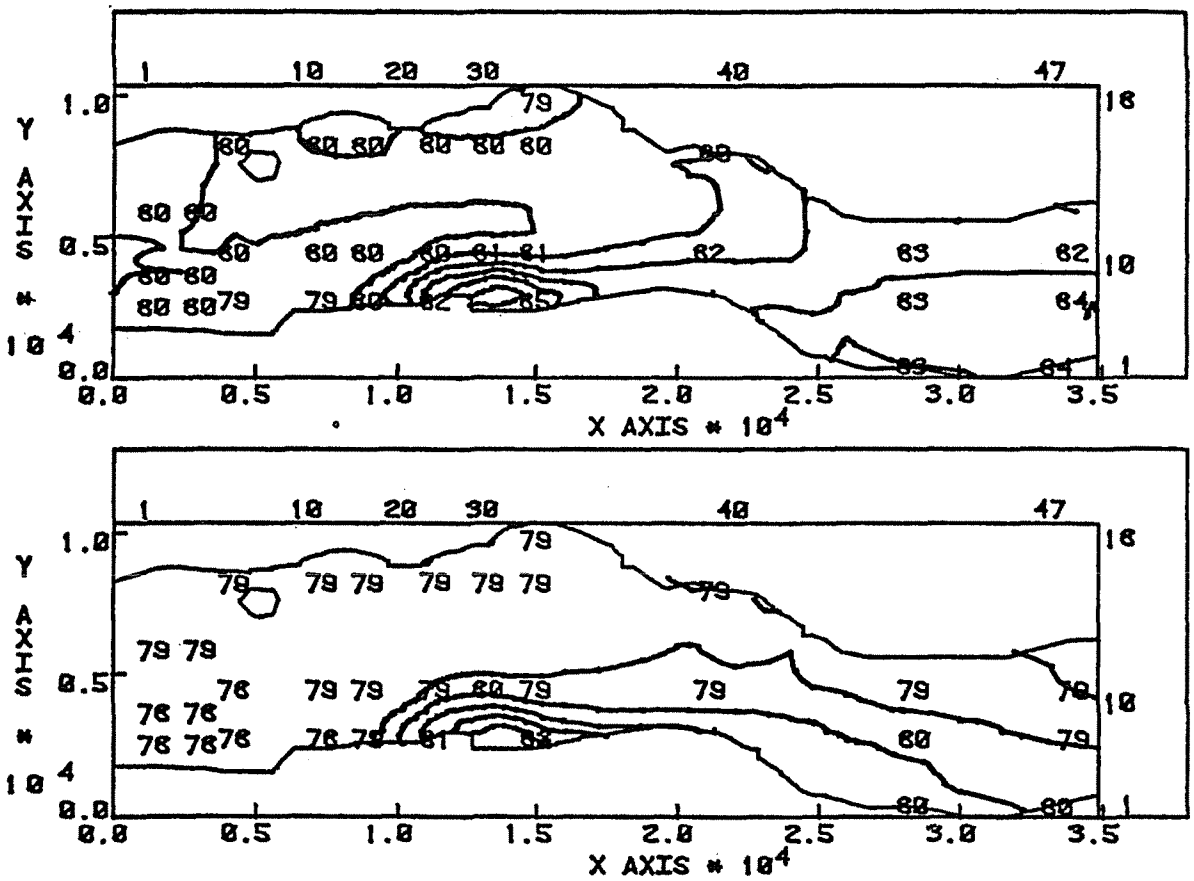

Figure 11.2 Computer simulation results for the surface and bottom temperature conditions (isotherms with 1°F gradation (1/1.8°C) in the Conowingo Pond Reservoir in the vicinity of the Peach Bottom Atomic Power Station at 9 a.m. on July 18, 1974, during reservoir conditions: downstream low flow slack water.

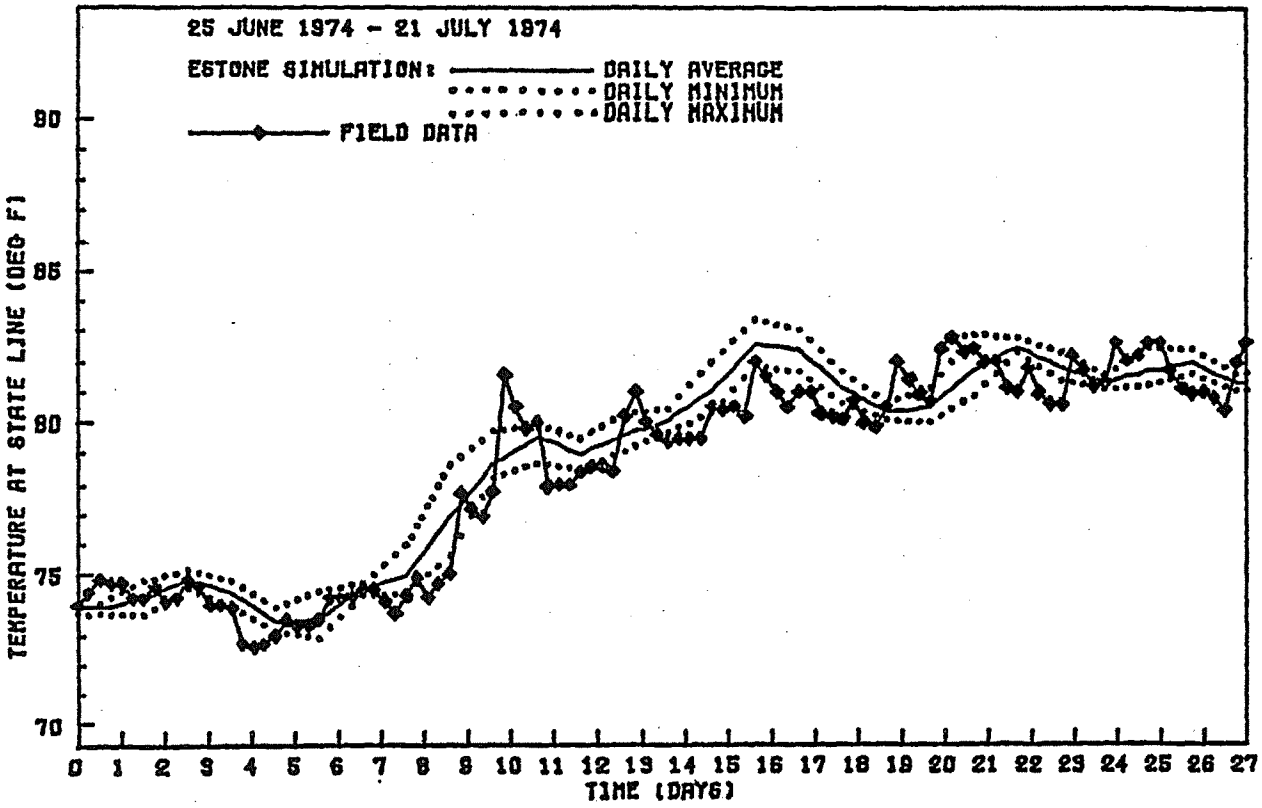

Figure 11.3 Estone simulation June 25, 1974 through July 21, 1974.

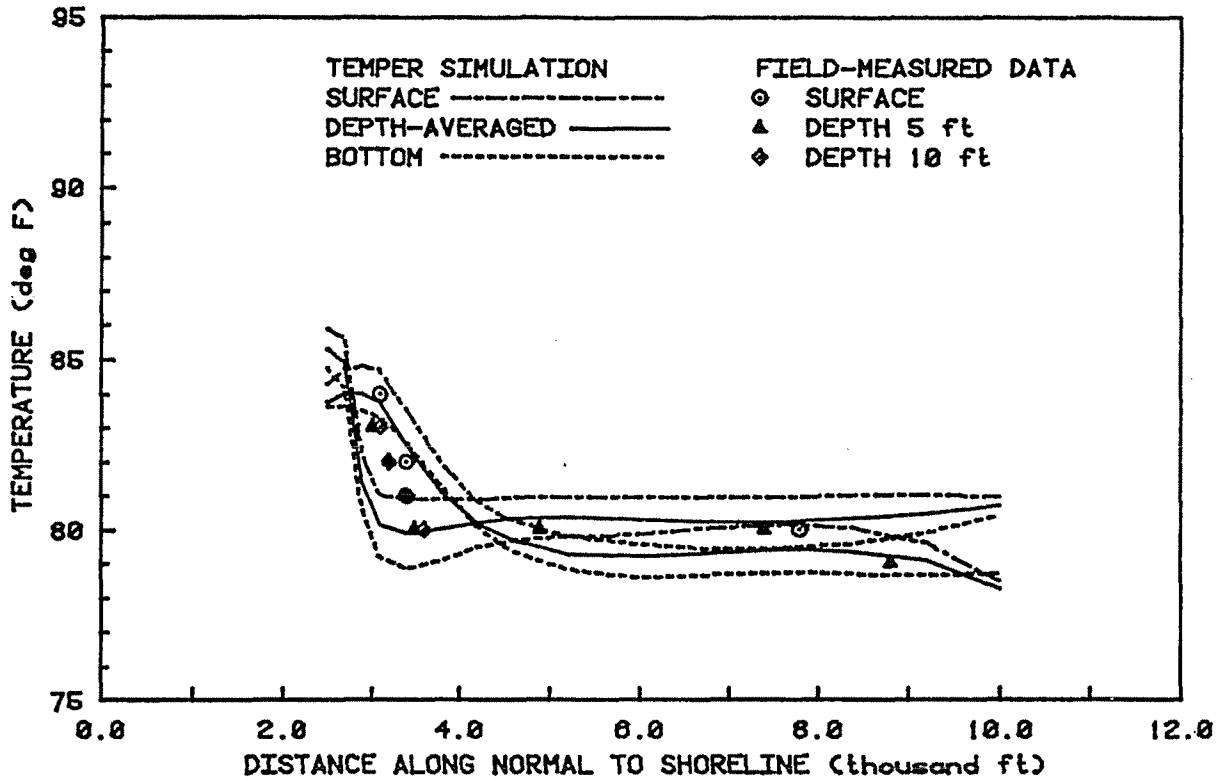

Figure 11.4 Comparison of the computer simulation results and the field-measured data for the temperature conditions along a transect at 1200 ft downstream from the discharge location of the Peach Bottom Atomic Power Station in the Conowingo Pond Reservoir from 8 a.m. to 1 p.m. on July 18, 1974.

(To convert ft to m, multiply by .3048.)

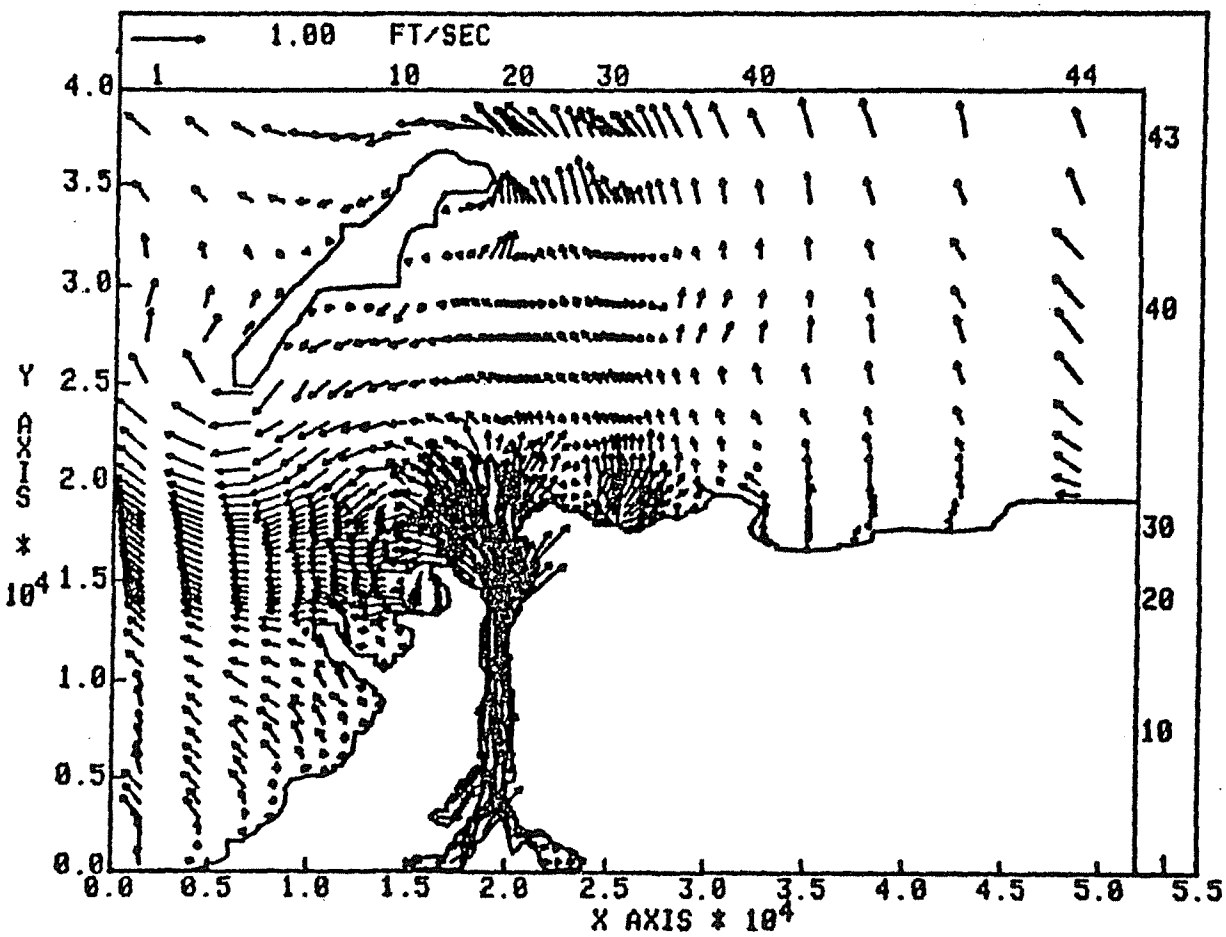

Figure 11.5 Computer simulation results for the two-dimensional depth-averaged flow velocity conditions in the Anclote Anchorage region for the actual Unit 1 operation of the Anclote Power Plant at 3 p.m. on June 25, 1975, during tidal stage: approximate maximum ebb.

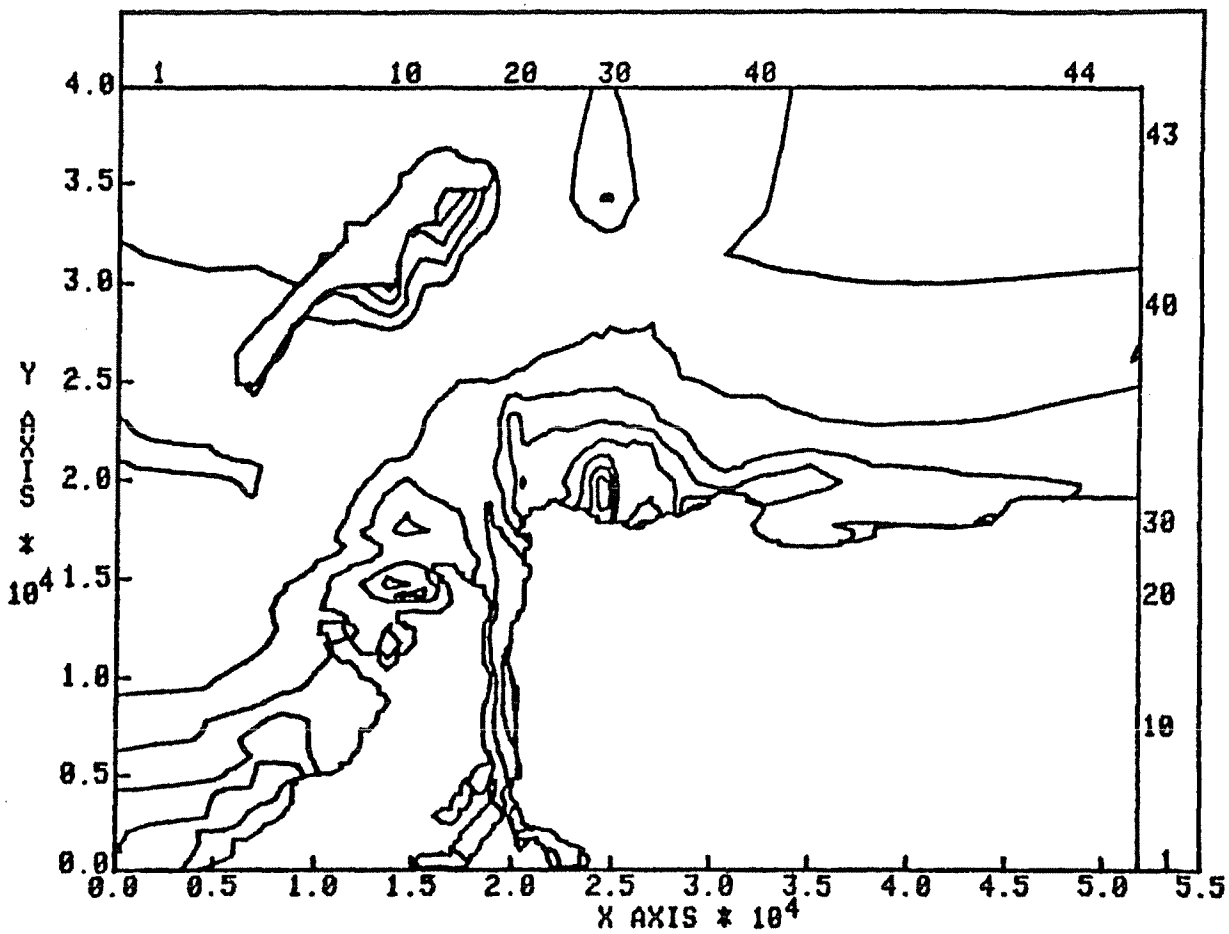

Figure 11.6 Computer simulation results for the two-dimensional depth-averaged water temperature conditions (isotherms with 1 F (1/1.8 C) gradation between minimum 84 F(28.9 C) and maximum 92 F(33.3 C)in the Anclote Anchorage region for the actual Unit 1 operational condition of the Anclote Power Plant at 3 p.m. on June 25, 1976, during tidal stage: approximate maximum ebb.

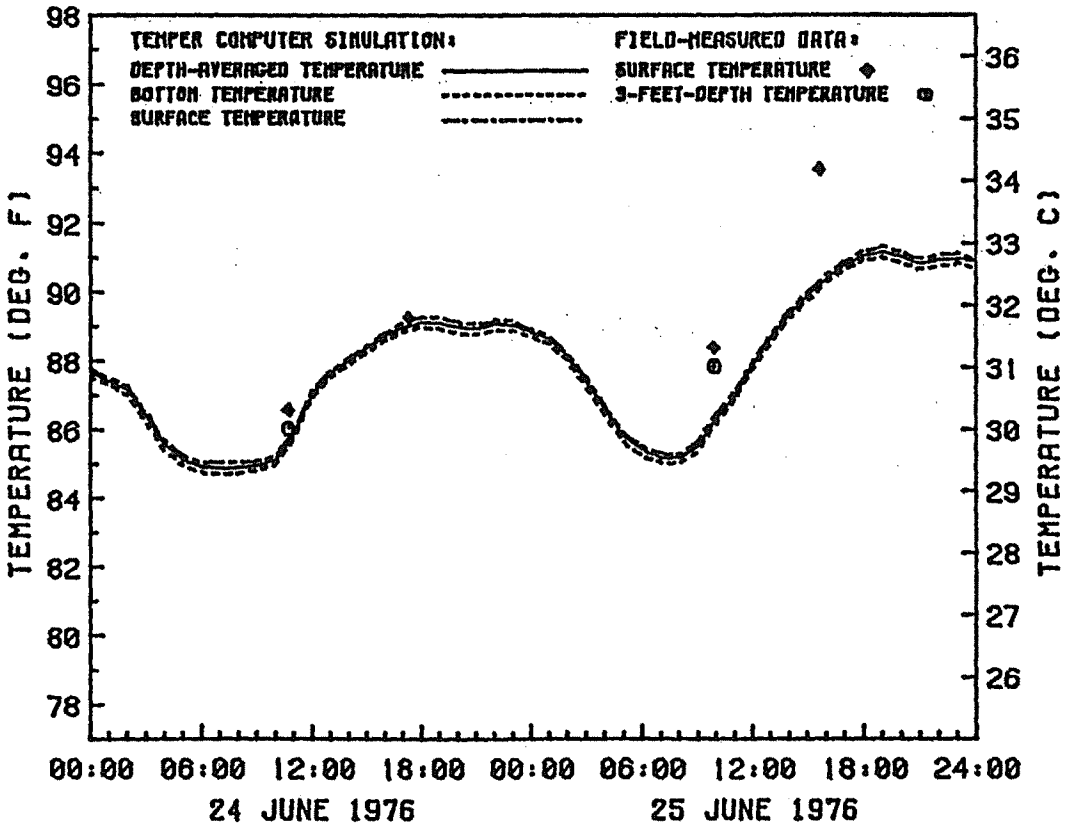

Figure 11.7 Comparison of the computer simulation results for the water temperature conditions (as continuous hourly variations) and the available field-measured water temperature data (intermittent) in the Anclote Anchorage region during the 2-day period June 24-25, 1976, at the field-sampling station 25.

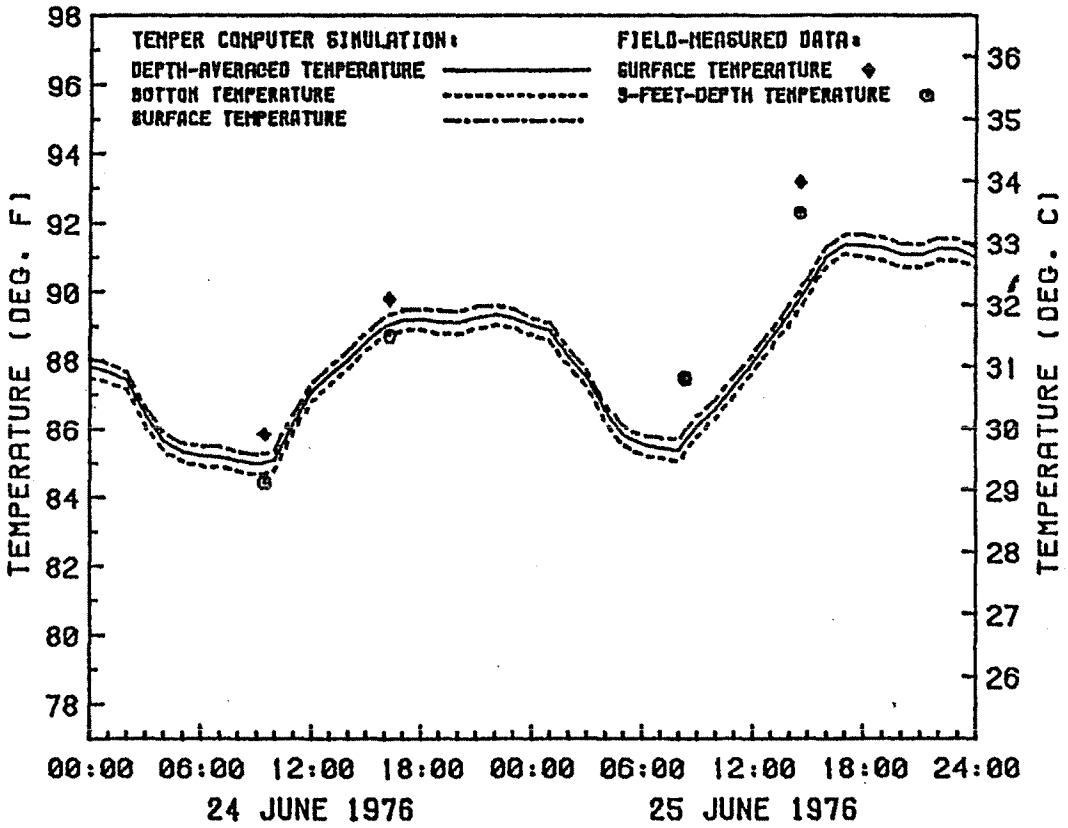

Figure 11.8 Comparison of the computer simulation results for the water temperature conditions (as continuous hourly variations) and the available field-measured water temperature data (intermittent) in the Anclote Anchorage region during the 2-day period June 24-25 1976, at the field-sampling station 1.

11.7 THERMAL EFFECTS (SCE, A-14, A-24/A-25)

It is true that the ambient temperature data supplied by the applicant (Attachment T) indicate the presence of lower ambient temperatures, at both the surface and the bottom, within the region of the San Onofre Kelp Bed than those predicted by the model. Typically, the discrepancy between the maximum values reported by the applicants and from the thermal model (for both surface and bottom) during the late summer is on the order of 4-5°C (7-9°F). However, the recently supplied values are for a period of record which spans only a few years (1975-1978). Thus, it is not possible to know if some of these data were collected during a period of time in which the waters are naturally warmer than long-term average. In evaluating the potential impacts of a long-lived facility such as SONGS (which will operate for up to 30 years), a worst-case evaluation is usually made to determine the effects which might occur under extreme conditions. Without knowledge of the relationship between the data supplied by the applicant and worst-case temperature conditions, these data cannot be relied upon for an assessment of the impacts on the kelp.

If the assumption is made that these data do include an interval in which there are temperatures which are warmer than usual (e.g., the warmest values reported in the last 15-20 years), then the conclusions of the applicant regarding the effects on kelp are probably correct. That is, the incremental temperature increase due to the operation of SONGS will not result in an adverse impact to the community, even under worse-case conditions.

The staff does not concur that the bottom water will necessarily remain unaffected.

The staff does not feel that the ambient temperature data available are complete enough for use in a worst-case analysis. Because such an analysis (based on the temperature data generated by the model) concluded that the impact to the benthic community will be insignificant (overall), it is clear that the effect under average conditions will likewise be insignificant. If the model does predict maximum temperatures which are unrealistically high, the conclusions based on such data provide additional assurances that the impacts will be negligible.

11.8 BIOLOGICAL RESOURCES (DOC, A-8/A-9; SCE, A-25/A-30; RJW, A-47)

The statement was not meant to imply that the only relationship between kelp beds and the commercial fishes is through the kelp detritus. Certainly, several of the commercially important species inhabit the beds (at least part of the time) for food-seeking activities and refuge. The paragraph was intended to portray, in brief, the ecological and commercial importance of kelp beds. Additional information on this subject is contained in the FES-CP.

Any revision to station design or operation for the express purpose of mitigating nonradiological impact to aquatic biota will be accomplished through procedures under the NPDES Permit Program administered by the California Water Quality Control Board. NRC is working closely with this Board and with other State resource agencies in the review of monitoring programs.

The cost-benefit analysis for the potential loss of biological resources due to the operation of SONGS 2 and 3 is addressed in the SONGS FES-CP, March 1973, Sections 13.2.4 and 13.4, and in Section 10 of this FES.

Technically, the statement is still correct. Although man-induced thermal effects may not be documented, their occurrence is likely in some areas.

It is true that the association of decreased kelp "health" with turbidity was made in conjunction with observations on the effects of sewage outfalls. However, the effect of turbidity on light attenuation is not a function of the source or type of the turbidity, except that a certain type of turbidity may not produce the same light reduction, at a given concentration, as another type of turbidity (e.g., as in the case of fine sand particles vs. suspended clay). Reference 15 includes a statement on the reduction of kelp "health" as a function of reduced available light for photosynthesis. It is reasonable to assume, therefore, that kelp "health" can be affected by many different types of turbidity.

It is true that nutrient depletion has been implicated in kelp canopy deterioration. It is also true that the exact mechanisms of kelp deterioration are not well known. Most studies have attributed cause-effect relationships between temperature and kelp demise, but the operating factors may well be complex, and may involve, for example, synergisms between several factors. To reflect this uncertainty, the text has been changed as per the suggested revision.

The study cited (number 13) gives one indication of the importance of kelp beds to fish communities. The relative importance of kelp for fish rearing, refuge, etc. may be disputed. However, for purposes of a worst-case analysis, it must be assumed that a more conservative interpretation is correct. It should be noted that the subject paragraph does not state that kelp beds are the most important fish habitat. Rather, it indicates that the community does have some unspecified importance.

The ecotypic variability of kelp temperature to tolerance is not well documented, though it may occur. Without definite knowledge, the more conservative values should be used in a worst-case analysis.

As stated earlier (see response to SCE, A-2), the ambient temperature data supplied by the applicants do not appear to be entirely adequate for an analysis.

Increased survace nutrient levels from outfall induced upwelling have not been adequately demonstrated, though the phenomenon may occur.

The discharge for SONGS will be more or less continuous (except during shutdowns and power reductions), although it is true that when the plume reaches the kelp bed it is not likely to impinge the bed for a long period of time. This is acknowledged in the text and is one major reason why the conclusion was reached that the effect on the kelp bed is not likely to be severe (p. 5-27, paragraph 5). To avoid ambiguity, the subject statement has been revised.

The reference to Sect. 5.3.1 as the basis for the 19°C figure has been deleted. It is, however, based on results of the staff's thermal model. If this temperature represents the extreme high end which occurs during an average year, then it may well represent a temperature which could occur over an extended period of time during a "warm year." Because the values from the model are conservative, the word "typical" has been deleted from that sentence.

The staff's thermal analysis (Sect. 5.3.1) does not support the conclusion that increases in bottom temperatures are unlikely. The statement remains valid, even if the turbid water is discontinuous and relatively low in suspended solids; i.e., the presence of any increased turbidity will add to the probability of detrimental effects occurring to the kelp bed.

The analysis of the effect of the operation of SONGS on the closest kelp bed (San Onofre) was based on the latest thermal-hydraulic predictions made by our staff. The staff agrees that if this assessment of temperature configurations proves to be inaccurate that the analysis of kelp bed effects would have to be reassessed.

The granting of a 316(a) exception for normal operation, if such is needed, will not affect the operating characteristics of the facility; thus, the pedicted impacts remain valid. If a 316(a) type process becomes required by the State which results in operational changes, the impacts of that altered operating mode will have to be assessed when such conditions are known.

11.9 WATER QUALITY (EPA, A-38/A-40)

Section 5.3.1.1 and Fig. 5.3 are based on the applicant's thermal analysis. Section 5.3.1.2 is a description of the staff's thermal analysis. This analysis includes all three units operating at 100% capacity and the ambient temperature is defined as the water temperature in the absence of all units. The possibility of recirculation among all units is an integral part of the staff's model. The results described in Section 5.3.1.2 address all aspects of the State thermal standards including excess temperatures at the surface of ocean substrates.

Additional information on the effects of the operation of the facility are found in the FES-CP, although in some cases the modification of operational characteristics since the CP stage has necessitated a reevaluation of the impacts. Such reanalyses are found in this document.

In the staff's opinion, the two documents (the FES-CP and FES-OL) provide "state-of-the-art" evaluations of how the acquatic ecosystem will be affected. In most cases, too little information is available to quantitatively predict the areal extent of an effect on a given species. For this reason, operational monitoring programs are required which are designed to detect significant changes which may occur so that mitigation can be instituted.

The terms "minimal," "acceptable," and "not significant" relate to a judgment made regarding the predicted impacts of the facility on the environment. A possible effect is termed insignificant if, for example, the impact is predicted to only occur locally in a nonunique, or widespread, population community of organisms, etc. When it is not possible to reach a firm conclusion regarding the significance of a projected impact (even under worst-case conditions), mitigation is either recommended immediately or an extensive monitoring program is stipulated.

The study report concerning use of the heat treatment process addresses a matter beyond the NRC's purview in accordance with the Federal Water Pollution Control Act Amendments of 1972. Thus, while the NRC must evaluate and consider the environmental impacts attributable to use of such heat treatment process, such consideration is limited to a determination of the impacts and their significance in terms of the cost-benefit analysis for this facility; any changes in the system or its use must be directed by the California Regional Water Quality Board and/or the Environmental Protection Agency. The applicant will provide the study report directly to those agencies, as well as to the NRC, when available.

For the foregoing reasons, we do not believe that the report itself is an integral part of the Draft Environmental Statement. Of course, as noted above, the NRC will consider the impacts attributable to the heat treatment process in the Final Environmental Statement as stated in Section 5.4.2.1. In this connection, the staff considers it to be no different than any other report of a study or analysis performed by a license applicant in support of its application. The staff is aware of no legal requirement which would give the report independent status such as EPA suggests, in the context of the NRC's licensing review. The status of this report in terms of the determination to be made under Section 316(a) of the FWPCA is a matter left to that agency charged with making that determination.

Sect. 5.4.2.2 concludes that significant impacts are unlikely, even under worst-case conditions. The effluent characteristics of SONGS must conform to the State standards prevailing at the time of the operation of the facility.

It is not the purpose of the staff analysis, as provided in the DES, to make rulings regarding statutory requirements, but rather to assess the impacts of proposed operation. In making this analysis it is not assumed that standards will be satisfied and, therefore, the environmental consequences of any violations resulting from the proposed plant operation is inherent in the staff's conclusions.

11.10 NEED FOR PLANT (MIL, A-45)

Table 2.2 of the FES relates to projected population growth within 16 km of the San Onofre site for the period 1976 to 2020.

Tables 8.3 and 8.4 are related to the electrical growth projected within the service areas of Southern California Edison Company and San Diego Gas and Electric Company for the periods 1976-1985. The combined annual growth rates for peak demand and energy for this period is 4.3 and 4.6%, respectively.

Population within 16 km of the site does not necessarily reflect electrical growth in the applicant's service areas.

11.11 SEISMOLOGY (EPA, A-40; MIL, A-45; RJW, A-49)

The staff's review and evaluation of the geological and seismological aspects of the San Onofre Nuclear Generating Station Units 2 and 3 is presented in the staff's Safety Evaluation Report, published December 1980. Included in the SER is a discussion of the potential for and nature of seismic activity at the site and its vicinity as well as of the design and construction measures taken by the applicants to prevent damage to the facility and its component parts. The staff considers that its assessment of the environmental impact of postulated accidents presented in Chapter 7 adequately accounts for the consequences of any accident caused by seismic activity. This chapter discusses the consequences of accidents regardless of cause.

Regarding the potential for affecting water quality and for offsite radiological contamination, to the extent such impacts are the result of airborne transportation of radionuclides, the consequences are included in the discussion in Chapter 7. The liquid pathway, because of the hydrological environment at the site, does not present a viable transport mechanism which could impact water quality or would otherwise result in offsite radiological consequences.

11.12 URANIUM PRICES (RJW, A-49)

The cost-benefit analysis in the DES is based on 1976 data, at which time the price of uranium was $18.10/kg ($40/lb) U_3O_8. Presuming SCE used the then existing U_3O_8 price in their cost-benefit analysis for SONGS 2 and 3, they would be using a price that reflected the rapid increase in prices in the 1973-1976 period. To extrapolate future prices on the basis of the 1973-1976 price increase would be erroneous in that uranium prices decreased 9% in real terms during 1977. Thus, it is inappropriate to consider a price escalation which is not even valid for a 5-year period of the uranium market for a cost-benefit analysis which covers the 30-year lifetime of a reactor. It would be just as appropriate (or inappropriate) to extrapolate the recent 9% decrease in uranium prices for use in the analysis. Many factors must be carefully investigated to estimate future uranium prices, and simplistic methods cannot be justified.

Long-term contracts are not generally tied to market prices at time of delivery or a 7% per year escalation, whichever is greater, based on current data. In fact, most long-term uranium requirements are not under contract, so it is inappropriate to make any generalization about the nature and terms of those contracts. Even if future contracts were based on the greater of market price or 7%/year escalation, it does not follow that fuel costs will increase to prohibitively high levels. If future prices were related to market prices and market prices do not increase substantially (it has not been established that they will), then the uranium cost component of fuel costs would not increase very much. And, if prices increase at 7%/year, they would probably just be keeping pace with inflation and thus not be relevant to a constant dollar analysis.

The cost of purchasing uranium is only one component of nuclear fuel costs, the other being, for example, separative work, UF_6 conversion, and fabrication. Thus, overall nuclear fuel costs would not escalate in proportion to the increase in uranium prices.

11.13 ACCIDENTS (HEW, A-10; MIL, A-45; RJW, A-49)

These comments were addressed to the Accident Section (Section 7) published in the Draft Environment Statement (DES), dated November 1978. In January 1981, the staff revised Section 7 and issued it for comment as a supplement to the DES. The January 1981 Supplement is included as Section 7 of this Final Environmental Statement (FES). The staff believes FES Section 7 is responsive to those accident comments previously addressed to the DES.

(FHA, A-53)

Part 50.13 of 10 CFR does not require a licensee "to provide for design features or other measures for the specific purpose of protection against the effects of (a) attacks...by an enemy of the United States...or (b) use or deployment of weapons incident to U.S. defense activities." The staff recognizes that acts of war would likely produce severe environmental impacts wherever they might take place.

(RJW, A-56, A-59)

The supplement is based on site-specific data, as described in Section 7.1.4.2. While not specifically stated in the supplement, U.S. average, year 2000 estimated, population data were used beyond 560 km (350 miles). The site-specific meteorological data used included lid heights to account for vertical mixing characteristics.

(RJW, A-58)

Both the staff and SAI used very similar methodologies in their analysis, and they both represent improvements over the Reactor Safety Study. There are some differences, however, in assumptions and data used in each study that lead to the variabilities or uncertainties that are inherent in such calculations. These differences appear in:

- accident release characteristics - probabilities and magnitudes;
- emergency response assumptions;
- meteorological data; and
- demographic data.

Specific consequence values that commentors quote from the SAI-OES report cannot be directly compared with those reported in the staff's draft supplement since the former are not associated with specified probability levels while the latter are. The staff has not made a

detailed comparison of the results of the two reports but judges that they are in agreement within the estimated bounds of uncertainties and assumptions associated with the current state of probabilistic risk assessments.

(RJW, A-58, A-59, A-60)

The studies of the San Onofre site relative to earthquake potential is extensively discussed in Section 2.5 of the Safety Evaluation Report (NUREG-0712, December 1980). The staff's position is that the safe shutdown earthquake is correctly determined for this site. A discussion of natural phenomena as initiators of accidents has been added to Section 7.1.4.2.

(RJW, A-58, A-59)

If Unit 1 had a meltdown, the staff agrees that it would impact the operation of Units 2 and 3. However, the ability to shut down both units following an accident at Unit 1 would not be impaired.

(RJW, A-59)

The reactor vessel was installed with its reference mark 180 degrees from the desired location. As discussed in the Safety Evaluation Report (Section 5.3.4), the flow skirt, which is not symmetrical, was installed in the direction to agree with the vessel's orientation and procedures for fuel handling, which reference the vessel orientation, were modified. No rewiring was necessary as a result of the error.

(RJW, A-59)

The dewatering well cavities were discussed in the Safety Evaluation Report in Section 2.5. It was determined that there would be no impact on seismic Category I structures.

(RJW, A-59)

The beach visitors were specifically addressed (e.g., Sections 7.1.3.2 and 7.1.4.6 and Table 7.1.4-5).

(RJW, A-60)

The staff has concluded that acts of sabotage, as initiating events, do not contribute significantly to the probability of accidents due to the Commission's safeguards requirements. Section 7.1.4.2 has been modified to discuss this point.

(RJW, A-60)

While it is true that one-half of the population of the State of California lies within 160 km (100 miles) of the San Onofre site, the staff does not consider this to be a relevant observation. The staff's focus on demographic data for site suitability and site comparison purposes has been traditionally within 80 km (50 miles) of plant sites.

The discussion in Section 7.1.4.3 indicates that most of the accident impacts occur within 50 miles of the site. The staff has compared the total population within 50 miles of the site with the total population within 80 km (50 miles) of other nuclear plant sites and has found that San Onofre does not have a uniquely large population. Moreover, it is important to note that, as stated in Section 7.1.4.2, the site-specific population projected to the year 2000 both in magnitude and distribution has been used in the calculations through all regions to 160 km (100 miles) and beyond. Those fractions of the consequences which take place up to 16, 48, 80, 160 km (10, 30, 50, 100 miles) or beyond, are accounted for in the results presented. The site does not have a uniquely large population contained within any of the above mentioned distances.

(RJW, A-60)

The San Onofre Units 2 and 3 at 3390 MWt are typical of the upcoming generation of reactors. The power level of each plant was specifically used in determining the inventory of the core for the risk calculations. Salem 1 is presently operating at a comparable power level of 3338 MWt.

(RJW, A-60)

The production of farm and dairy products is specifically considered in the calculation. Differences among the states (and countries) potentially impacted are taken into account.

(RJW, A-60)

The impacts within the Mexican borders were included in the evaluation. The method of determination of data for Mexican agricultural products is discussed in Section 7.1.4.2. Although not explicitly stated, the population within the Mexican border was included on a site-specific basis out to 560 km (350 miles) from San Onofre.

(RJW, A-61)

The staff recognizes the potential efficacy of drugs in mitigating consequences of offsite exposures. However, in the case of potassium salts of stable iodine, the staff does not require provision for distribution to the public.

(RJW, A-61)

Section 7.1.4.4 discusses that the condemning of foodstuffs was specifically considered and the interdiction of contaminated property "...until it is either free of contamination or can be economically decontaminated" was assumed.

(RJW, A-61)

The subject of filtered venting systems for the containment is being addressed in rulemaking, as discussed in NUREG-0660, 2.B.8. The whole subject of TMI-2-related improvements and the fact that no credit would be taken for them is discussed in the last paragraph of the section cited.

(RJW, A-61)

It is the staff's position that such a "worst case accident" is much too remote and speculative to require analysis under NEPA.

(UCS, A-63)

The staff believes that its treatment of a multiplicity of possible accident scenarios represents a reasonable and appropriate implementation of the guidance provided in the Commission's Statement of Interim Policy.

(UCS, A-63)

The probabilities of occurrence of releases in the nine categories are explicitly given in Table 7.3 and the probabilities of occurrence of specific levels of environmental consequences are given in Table 7.4. The staff judges that this is within the intent of the quoted part of the sentence and the additional directive in the Interim Policy which states: "The environmental consequences of releases whose probability of occurrence has been estimated shall also be discussed in probabilistic terms." See also the staff's answer to Joint Intervenors RJW, A-58.

(UCS, A-64)

The staff has presented a measure of individual risk in Figures 7.7 and 7.8. Table 7.4 and its associated figures and Table 7.5 provide group information. The discussion of relative susceptibility of various sub-groups of the population is given in Section 7.1.1.3. The staff judges that this conforms to the further directive that the discussion be "...in a manner that fairly reflects the current state of knowledge regarding such risks."

(EPA, A-66)

The Supplement is a replacement for Chapter 7 in the existing Draft Environmental Statement for the Operating License stage (November 1978). It is not a replacement for the accident sections of the Construction Permit stage Environmental Statements of 1973.

(EPA, A-66)

Nine tables could have been provided to show the impact contributions of the nine categories. It is the staff's judgment, however, that the summary table, reflecting sums of the contributions from all of the categories, is sufficient. Information regarding the relative contributions of the release categories is available in the Reactor Safety Study, WASH-1400.

(EPA, A-66)

The Design Basis Accidents are included because they are used in the Safety Evaluation Report to assess the adequacy of the performance of certain engineered safety features. In the SER, the DBAs are compared to the suitably small fractions of 10 CFR 100 for those accidents that are considered likely (infrequent accidents).

(EPA, A-66)

The DBAs are judged not to be significant contributors to environmental risks and have not been subjected to the same kind of probabilistic analysis as the more severe accidents that are treated.

(EPA, A-66)

The staff believes that it is more informative to discuss the environmental risks associated with accidents separated from those attributable to normal operations. Both may be found in the Final Environmental Statement. Risks associated with the operation of both Units 2 and 3 are, to a first approximation, the sum of the risks associated with each unit individually.

(EPA, A-67)

We agree certain biological changes in children and adults may be detected occasionally at doses as low as 10 rem (e.g., slight, temporary reductions in circulating lymphocytes). However, at doses of 25 rem or greater, such effects become measurable in nearly all exposed persons. In addition, although such changes have no physiologically significant impact, they can be clinically measured. We selected 25 rem as a point above which potentially serious effects due to radiation exposure (e.g., prodromal vomiting) become apparent to physicians and a point below which no difference between exposed and unexposed populations is apparent in terms of latent cancer incidence.

(EPA, A-67)

The NRC State Liaison Officer has informed us that the Region IX RAC has completed its review of the local plans for the environs of San Onofre. The licensee has transmitted to the NRC copies of emergency plans for the following:

San Onofre, San Clemente and Daheny State Park and Beach Areas

San Juan Capistrano City

Camp Pendleton

Orange County

Unified San Diego County

Interagency Agreement between San Diego County, Orange County, City of San Clemente, City of San Juan Capistrano; Marine Corps, Camp Pendleton; State Department of Parks, Pendleton Coast Area.

The staff preliminary review of these documents affirms its judgment that the plans are, in fact, in an advanced stage of development even though they have not been submitted for formal review. A full-scale exercise for the San Onofre site and its environs is scheduled for May 13, 1981.

(EPA, A-67)

The NRC staff Safety Evaluation Report, dated February 1981, states that the San Onofre onsite emergency plan, when revised in accordance with the applicant's commitments, will provide an adequate planning basis for an acceptable state of emergency preparedness, and will meet the requirements of 10 CFR Part 50 and Appendix E, thereto. This is still the staff's conclusion.

The SER states that the plan must be revised to address the final criteria and implementation schedule for the emergency centers and their functions, emergency manpower levels, and upgraded meteorological program, and to address the impact of earthquakes on emergency plans for the site and its environs. The NRC staff position is that the emergency plans are sufficiently complete to justify the estimates of parameters used in the consequence model.

It is true that the State of California does not use the U.S. EPA Protective Action Guides (PAGs). The State of California has elected to base its Protective Action Guides on the concept that no member of the general public should receive more than 500 millirem per year. The emergency plans of the local authorities in the environs of the San Onofre plant have followed the State's guidance. This guidance is more conservative than the EPA guidance, i.e., protective actions would be recommended at a lower projected dose. Consequently, it is reasonable to expect that if protective actions were to be taken at a lower value of projected dose, then exposures would be reduced.

(EPA, A-67)

The figure has been revised to present a more meaningful directional risk. The meaning of the new figures is discussed in Section 7.1.4.6. The scale of the figures has been expanded (a smaller distance from the plant shown) and it has been redrawn in an attempt to improve legibility.

(EPA, A-67)

Standard methods for estimating costs of reactor building cleanup and decontamination and replacement power for the economic risk calculations are under development. Reasonable estimates of plant decontamination and replacement power have been made, however, and are discussed in Section 7.1.4.6. Staff conclusions on the benefit cost balance are reported in Section 10 of the FES.

(SCE, A-68)

It is clearly stated in the third paragraph of Section 7.1.4.1 that the evaluations of the limiting faults and infrequent accidents are used to implement the provisions of 10 CFR 100. The conclusions regarding siting are in the Safety Evaluation Report and its supplements.

(SCE, A-69)

Section 7.1.4.2 states that the estimates of the consequences may have as large error bounds as for the probabilities. Any uncertainty in the fractions of nuclides released contributes to the error bounds on the consequences, as well as uncertainties in the meteorological and health effects models. The subject of releases of certain nuclides, mainly the radioiodines, is presently under review by the staff.

APPENDIX A
COMMENTS ON DRAFT ENVIRONMENTAL STATEMENT

APPENDIX A

COMMENTS ON DRAFT ENVIRONMENTAL STATEMENT

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UNITED STATES DEPARTMENT OF AGRICULTURE
SCIENCE AND EDUCATION ADMINISTRATION

OFFICE OF THE DEPUTY DIRECTOR FOR
AGRICULTURAL RESEARCH
WASHINGTON, D.C. 20250

Subject: NRC Draft Environmental Statement

To: William H. Regan, Jr.
U.S. Nuclear Regulatory Commission
Environmental Projects Branch 2
Division of Site Safety and Env. Analysis
Washington, D.C. 20555

We have reviewed the draft environmental impact statement entitled San Onofre Nuclear Generating Station, Units 2 and 3, Southern California Edison Company, San Diego Gas & Electric Company, dated November 1978.

We have no comments to add to the evaluation provided by your staff. We do appreciate the opportunity of reviewing this statement.

H. L. BARROWS
Acting Deputy Assistant Administrator

A-2

790103 0193

U.S. DEPARTMENT OF AGRICULTURE
ECONOMICS, STATISTICS, and COOPERATIVES SERVICE
WASHINGTON, D.C. 20250

December 8, 1978

SUBJECT: Draft Environmental Statement

TO: William H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and
Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

We have no comments on the Draft Environmental Statement related to operation of San Onofre Nuclear Generating Station, Units 2 and 3 by Southern California Edison and San Diego Gas and Electric Companies.

MELVIN L. COTNER
Director
Natural Resource Economics Division

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A-3

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT
AREA OFFICE
2500 WILSHIRE BOULEVARD, LOS ANGELES, CALIFORNIA 90057

REGION IX
450 Golden Gate Avenue
P.O. Box 36003
San Francisco, California 94102

December 19, 1978

IN REPLY REFER TO:

U.S. Nuclear Regulatory Commission
Attention: Director, Division of Site Safety
and Environmental Analysis
Washington, D.C. 20555

Gentlemen:

Subject: San Onofre Nuclear Generating Station
Units 2 and 3
Draft Environmental Statement
Docket Nos. 50-361 and 50-362

We have reviewed the captioned document and have no comments to offer on it. There is no need to send this office a copy of the Final Environmental Statement.

Sincerely,

Roland E. Cofield, Jr.
Area Manager

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7901080142

DEPARTMENT OF THE ARMY
LOS ANGELES DISTRICT, CORPS OF ENGINEERS
P. O. BOX 2711
LOS ANGELES, CALIFORNIA 90053

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SPLED-E

2 January 1979

Mr. Wm. H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and Environmental Analysis
United States Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

This is in response to a letter from your office dated 30 November 1978 which requested review and comments on the Draft Environmental Impact Statement for the San Onofre Generating Station, Units 2 and 3, proposed by Southern California Edison Company and San Diego Gas and Electric Company.

The proposed plan does not conflict with existing or authorized plans of the Corps of Engineers. We have no comments on the environmental statement for the proposed action.

Thank you for the opportunity to review and comment on this statement.

Sincerely yours,

NORMAN ARNO
Chief, Engineering Division

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UNITED STATES DEPARTMENT OF AGRICULTURE
SOIL CONSERVATION SERVICE
2828 Chiles Road, Davis, CA 95616

January 9, 1979

William H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and
Environmental Analysis
United States Nuclear Regulatory
Commission
Washington, D. C. 20555

Docket No.: 50-361
and 50-362

Dear Mr. Regan:

We acknowledge receipt of the draft environmental statement for San Onofre Nuclear Generating Station, Units 2 and 3, Southern California Edison Company, San Diego Gas & Electric Company in San Diego County, California, that was addressed to USDA Soil Conservation Service on November 30, 1978, for review and comment.

We have reviewed the above draft and have the following comments.

1) Provisions for erosion control and water management during construction as well as conservation treatment of disturbed areas following construction were inadequately addressed. We suggest that an erosion control plan be developed to adequately address the erosion hazard both during and following construction.

2) Approximately 10 acres of prime land will be lost to access roads and transmission towers. Mitigation or projected impacts from this loss were not adequately discussed. We suggest further discussion in the statement to address the prime land issue.

We appreciate the opportunity to review and comment on this proposed project.

Sincerely,

FRANCIS C. H. LUM
State Conservationist

7901260144

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D

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

January 17, 1979

IN REPLY REFER TO:

Mr. William H. Regan
Division of Site Safety and
Environmental Analysis
Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Regan:

I am replying to your request of November 30, 1978 to the Federal Energy Regulatory Commission for comments on the Draft Environmental Impact Statement for the San Onofre Nuclear Station Units 2 and 3, California. This Draft EIS has been reviewed by appropriate FERC Staff components upon whose independent evaluation this response is based.

The staff concentrates its review of other agencies' environmental impact statements basically on those areas of the electric power, natural gas, and oil pipeline industries for which the Commission has jurisdiction by law, or where staff has special expertise in evaluating environmental impacts involved with the proposed action. It does not appear that there would be any significant impacts in these areas of concern nor serious conflicts with this agency's responsibilities should this action be undertaken.

Thank you for the opportunity to review this statement.

Sincerely,

Jack M. Heinemann
Advisor on Environmental Quality

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7901220093

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

JAN 18 1979

In Reply Refer To:
ER 78/1161

Mr. William H. Regan, Jr.
Chief, Environmental Projects Branch 2
Division of Site Safety and
Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

The Department of the Interior has completed its review of the draft environmental statement for San Onofre Nuclear Generating Station Units 2 and 3. We have comments in only two areas of our jurisdictional concern as set forth below.

Recreation Resources

The discussion of recreation impacts states that restrictive use of the beach area was unanticipated at the time issuance of the construction permit was being considered. Since no explanation is given, it is unclear to us how such a significant impact, the loss of recreational and scenic open space, could have been overlooked during the earlier planning stages. The final statement should disclose the reasons which now require restrictions upon beach use.

Although there is now recognition of the impact, we see no attempt being made by the applicant to mitigate the loss of recreation space and opportunity. With respect to the scenic quality of the area, we find the intended plan to construct an eight foot chain-link fence extending over three-fourths of a mile along the beach quite objectionable. Design of the walkway deserves much more attention. Given the fact that this stretch of beach is rather removed from the developed portions of the state park units and therefore receives minimal use and given the scenic nature of the beach area and bluffs it would certainly seem more preferable and perhaps sufficient to consider posting the area as to its restrictive use. If a barrier is still needed, a more aesthetically sensitive, light railing may best fulfill the need to restrict access.

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Cultural Resources

We are pleased that the NRC staff has directed the applicant to consider historic, archeological, and Native American cultural resources in its planning process. We understand that existing and possible new transmission corridors will be surveyed for such resources. However, we strongly urge that the applicant allow enough flexibility in its planning to actually take the results of these surveys into account in its final placement of tower bases, access roads, and proposed substations. This would include allowing the State Historic Preservation Officer enough time to properly evaluate the surveys results and make appropriate recommendations. In addition, any new land used for material storage or other project activities outside the transmission corridors should also be checked for cultural resources.

We hope these comments will assist your efforts in preparing the final environmental statement.

Sincerely,

Larry E. Meierotto
Deputy Assistant SECRETARY

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LAW OFFICES OF
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SUITE 1030
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(714) 835-7787

January 19, 1979

United States Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Director, Division of Site, Safety and Environmental Analysis

Gentlemen:

Pursuant to the notice published in the Federal Register with respect to comments on the Draft Environmental Statement (DES), the Cities of Anaheim and Riverside, California wish to submit the following comments.

Anaheim and Riverside believe the Final Environmental Statement (FES) should be amended in Section 3, entitled "Need for the Station", to reflect probable ownership by the Cities of a portion of Southern California Edison Company (SCE), 80% interest in Units 2 and 3.

The Applicants and Anaheim and Riverside, entered into a Letter Agreement dated November 1, 1977 which incorporated other proposed Agreements, including a Participation Agreement which provides for Anaheim to acquire 1.66% of SCE's 80% interest in Units 2 and 3, and for Riverside to acquire 1.79% of Edison's 80% interest in Units 2 and 3. The Letter Agreement was entered into by the Parties because a question was raised as to whether SCE or SDG&E would lose the investment tax credit with respect to its ownership share of Units 2 and 3 due to Anaheim and Riverside, public agencies, owning an undivided interest in Units 2 and 3. The Letter Agreement further provides, however, that when this question is satisfactorily resolved in the opinion of each party to said Agreement, the Participation Agreement attached thereto will be executed by the Parties.

The Internal Revenue Service has issued Revenue Ruling 78-268, which holds that undivided ownership in property by exempt and non-exempt entities does not of itself disqualify the portion of the property owned by the non-exempt entity from taking investment tax credit with respect to its share of such property. Moreover, SCE and SDG&E received a private letter ruling, dated August 16, 1978 which holds with respect to San Onofre Nuclear Generating Station, Units 2 and 3, that SCE and SDG&E will not lose investment tax credit with respect to their undivided interest in Units 2 and 3 after the sale of the interest to Anaheim and Riverside. However, that Private Letter Ruling contained language which SCE and SDG&E believe to be ambiguous and therefore on October 27, 1978 they filed a Request for Clarification of the Private Letter Ruling of August 16, 1978. The Request for Clarification is still pending before the Internal Revenue Service, but we believe it will be favorably acted upon in the next several weeks.

Anaheim and Riverside are currently, and have for some years, been wholesale

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customers of SCE. Anaheim and Riverside purchase all of their capacity, and most of their energy requirements from SCE. Anaheim and Riverside have agreements with Nevada Power Company wherein each City purchases economy non-firm energy from Nevada Power Company. These agreements will expire by their own terms in 1980. Anaheim and Riverside do not currently own any generating resources.

In 1978 Anaheim's peak demand was 388 megawatts. The estimated peak demand for 1978 was 394 megawatts. During 1978 Anaheim purchased two billion kilowatt hours of energy. For the period 1979 through 1990 it is estimated the peak demand for Anaheim will increase in differing amounts. The smallest amount of increase for electrical demand in any year during that period is estimated to be 3.1 percent and the highest amount of increase for any year 4.8 percent. It is also estimated for the same period of time that energy requirements for Anaheim will increase with the lowest estimated annual increase being 3.6 percent and the highest estimated annual increase being 5.0 percent.

In 1978 Riverside's peak demand was 278 megawatts. The estimated peak demand for 1978 was 260 megawatts. During 1978 Riverside purchased over one billion kilowatt hours of energy. For the period 1979 through 1990 it is estimated the peak demand for Riverside will increase with the smallest annual increase to be 4.0 percent and the highest annual increase to be 5.4 percent. It is also estimated for the same period of time that the energy requirements for Riverside will increase with the lowest annual increase to be 4.0 percent and the highest annual increase to be 5.4 percent.

The acquisition of an ownership interest in Units 2 and 3 by Anaheim and Riverside does not change the conclusion that the Units are needed to meet the electrical load served by SCE, Anaheim and Riverside. The load forecasts of SCE include the loads served by Anaheim and Riverside. Therefore, whether you include the loads of Anaheim and Riverside in the SCE forecast of loads or break them out and identify them separately, the need for the station is the same.

Very truly yours,

Alan R. Watts

ALAN R. WATTS
Special Counsel
Cities of Anaheim and Riverside

ARW:jm:D:11

cc: Attached Listing

Mr. John Bury
Southern California Edison Company
2244 Walnut Grove Avenue
P. O. Box 800
Rosemead, California 91770

Mr. Mark Medford
Southern California Edison Company
2244 Walnut Grove Avenue
P. O. Box 800
Rosemead, California 92672

Mr. Robert J. Pate
U. S. Nuclear Regulatory Commission
P. O. Box 4167
San Clemente, California 92672

Samuel B. Casey, Esq.
David R. Pigott, Esq.
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Janice E. Kerr, Esq.
J. Calvin Simpson, Esq.
Lawrence Q. Garcia, Esq.
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Wm. H. Regan, Jr.
Environmental Projects Branch 2
Division of Site Safety and Environmental Analysis
United States Nuclear Regulatory Commission
Washington, D. C. 20555

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David W. Gilman
Robert G. Lacy
San Diego Gas & Electric Company
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San Diego, California 92112

Phyllis M. Gallagher, Esq.
Suite 220
615 Civic Center Drive West
Santa Ana, California 92701

Gordon W. Hoyt
Utilities Director
P. O. Box 3222
Anaheim, CA. 92803

Everett C. Ross
Public Utilities Director
City of Riverside
3900 Main Street
Riverside, CA. 92522

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UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Science and Technology
Washington, D.C. 20230
(202) 377-3444 4335

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January 22, 1979

Director, Division of Site Safety
and Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Sir:

This is in reference to your draft environmental impact statement entitled "San Onofre Nuclear Generating Station, Units 2 and 3, Southern California Edison Company, San Diego Gas & Electric Company." The enclosed comments from the National Oceanic and Atmospheric Administration are forwarded for your consideration.

Thank you for giving us an opportunity to provide these comments, which we hope will be of assistance to you.

We would appreciate receiving 10 copies of the final statement.

Sincerely,

Sidney R. Galler
Deputy Assistant Secretary
for Environmental Affairs

Enclosures from: Gordon G. Lill--National Ocean Survey
Gerald V. Howard--National Marine Fisheries Serv

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UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL OCEAN SURVEY
ROCKVILLE, MD 20852

OA/C52x6

JAN 10 1979

TO: PP - Richard L. Lehman

FROM: OA/Cx1 - Gordon G. Lill

SUBJECT: DEIS #7812.06 - San Onofre Nuclear Generating Station, Units 2 and 3

The subject statement has been reviewed within the areas of NOS responsibility and expertise, and in terms of the impact of the proposed action on NOS activities and projects.

The following comments are offered for your consideration.

Section 2.3.1, Surface-water hydrology, has been found to be very adequate for the purposes intended. The authors are to be commended for the thorough bibliography on the subject.

NOS concurs with and encourages the oceanographic monitoring program described in Section 6.2.2. We feel this program will ensure environmental protection and help allay public concern.

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U.S. DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
National Marine Fisheries Service
Southwest Region
300 South Ferry Street
Terminal Island, California 90731

Date : January 8, 1979 FSW33/JJS

To : EC, Office of Ecology and Conservation
H. H. Schmelzer

Thru : F7, Kenneth R. Roberts, Acting Director, Office of Habitat Protection

From : FSW, Gerald V. Howard, Regional Director, Southwest Region

Subject: Review of DEIS No. 7812.06 - San Onofre Nuclear Generating Station, Units 2 and 3 (NRC)

The subject DEIS which accompanied your memorandum of December 8, 1978, has been reviewed by the National Marine Fisheries Service. The following comments are offered for your consideration:

Specific Comments

5. Environmental Effects of Station Operation

5.4 Environmental Impacts

5.4.2 Impacts on the aquatic environment

Page 5-26, paragraph 7, Kelp

In paragraph 7 little information is included documenting the importance of kelp to coastal commercial fish species. Information available in the California Department of Fish and Game Fish Bulletin 139 (Quast, 1968) provides some insight in that regard.

Data developed by Jay Quast of the then U.S. Bureau of Commercial Fisheries, and included in that publication, indicate that in his studies he found more than twenty commercially important fish species occurring in the kelp beds off southern California. According to those studies the relationship of many of those species to the kelp habitat was more extensive than indicated by the final sentence of the subject paragraph. This should be reflected in the taxt of the final EIS.

6. Environmental Monitoring

6.3 Operational Monitoring Programs

6.3.3 Aquatic biological monitoring

Page 6-7, paragraph 1

The concept of continuing a kelp study program into the operational stage of SONGS is a good one. However, should those studies determine that significant harm is occurring to that resource, then some method of compensation satisfactory to the National Marine Fisheries Service would need to be developed. This should also apply to the studies being conducted on fish impingement at SONGS 2 and 3.

If such measures are not adopted and adverse impacts do appear the monitoring program may be merely documenting the demise of a valuable coastal resource.

10. Benefit-Cost Summary

10.7 Summary of Benefit-Cost

Page 10-3, paragraph 3

The potential additional cost of compensating for loss of biological resources due to the operation of SONGS 2 and 3 should be addressed.

A-9

LITERATURE CITED

Quast, Jay C. 1968. 8. Observations on the food of the kelp-bed fishes. In: California Department of Fish and Game, Fish Bulletin 139. Pp 109-142.

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE
PUBLIC HEALTH SERVICE
FOOD AND DRUG ADMINISTRATION
ROCKVILLE, MARYLAND 20857

January 25, 1979

Mr. William H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety
and Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

The Department of Health, Education, and Welfare has reviewed the health aspects of Draft Environmental Statement related to operation of the San Onofre Generating Station, Units 2 and 3, Southern California Edison Company and San Diego Gas and Electric Company and has the following comments to offer.

Section 5.5 Radiological Impacts

The individual doses as identified in Table 5.3 are all within Appendix I, 10CFR50 design objectives and should assure adequate radiation protection of the public for routine releases. However, it should be recognized in this section that 10CFR190 promulgated by EPA became effective in January 1979. A statement should be included indicating that SONG 2 and 3 will also meet this standard.

It is recognized that there are many variables that influence occupational exposure for a specific plant. However, a recent Atomic Industrial Forum study of occupational exposures showed for a PWR a total of 694 man-rem per year as a representative PWR exposure pattern. As a conservative estimate the projected occupational exposure impact of the two-unit San Onofre Station would be 1400 man-rem per year.

The summary of environmental consideration for uranium fuel cycle shown in Table 5.8 appear to be within acceptable radiation protection limits. However, some additional explanation within the test or by a footnote is needed for the disposal of solids. In particular, the statement that TRU and HLW would be buried at a Federal Repository should be modified to indicate alternatives for disposal of these waste in the event the Federal repository is not operational when required by plant operations.

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Section 6.2.5 Radiological Monitoring Program

The preoperational monitoring program presented in Section 6.1.5 of the Environmental Report is adequate for meeting the objective stated in this section. The establishment of the radiological monitoring program prior to start of operations should provide the necessary data to verify the effectiveness of in-plant controls and to provide assurance that undetected radioactivity will not build-up in the environment.

Section 7 Environmental Impact of Postulated Accidents

The estimated exposure of the population within a 50 mile radius of the plant shown in Table 7.2 cannot be adequately evaluated without some specific data in the text on the source term. Without such data it is possible to assume that the environmental consequence as a result of a class 8 accident could be more severe than indicated in the unlikely event of such an accident.

There is no indication in this section or previous chapters on emergency response planning to mitigate the consequences of an accident that could impact on the offsite population. A discussion of the arrangement that has been made with State and local authorities should be included in this section.

The discussions in paragraph 4, page 7-2 on the Reactor Safety Study (WASH-1400) relative to discussion with EPA is outdated (1973), and since it discusses scope of the study, and not results, should be removed. More importantly, a statement should be included on the technical review or conclusions that have been provided by EPA, other Federal agencies or independent reviewers. Such a statement would be helpful in accepting the low environmental risks associated with the postulated radiological accidents.

On the basis of this review it is concluded that the San Onofre Nuclear Generating Station, Units 2 and 3 can be operated to meet current radiation protection guidance and provide adequate protection of the public health and safety.

Sincerely yours,

Bernard Siegel for

Charles L. Weaver
Consultant
Bureau of Radiological Health

Southern California Edison Company
P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

J. H. DRAKE
VICE PRESIDENT

TELEPHONE
213-572-2288

February 2, 1979

Director, Office of Nuclear Reactor Regulation
Attention: William H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and Environmental Analysis
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Gentlemen:

Subject: San Onofre Nuclear Generating Station
Units 2 and 3
Docket Nos. 50-361 and 50-362

In accordance with your request of November 30, 1978, the Southern California Edison Company and the San Diego Gas & Electric Company have reviewed the Draft Environmental Statement (DES) related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3. Enclosed are comments generated from this review.

Should have any questions or require clarification regarding these comments, please contact me.

Very truly yours,

J. H. Drake

Enclosure

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ATTACHMENTS

A	Figure 6.14, page 61 of Reference (5)
B	Figure 6.29, page 76 of Reference (5)
C	Figure 6.34, page 81 of Reference (5)
D	Figure A-7, page A-15 of Reference (5)
E	Figure 6.8, page 47 of Reference (5)
F	NOAA Climatological Data, July 1975
G	" " , July 1976
H	" " , April and July 1977
I	" " , July 1978
J	Air Temperatures at SONGS
K	Del Mar Current Meter and Temperature Data, May-December 1978
L	San Onofre Area Current and Temperature Data, May-August 1978
M	Pages 103-106 of DES reference 8
N	Figure 1 Surface Isotherms for 0.0 knots
O	Figure 2 " " " 0.1 "
P	Figure 3 " " " 0.25 "
Q	Reference (19)
R	Reference (20)
S	Reference (21)
T	Temperature Data from References (8), (22), (23) and (24)
U	Reference (2)
V	Bottom (30') Water Temperatures at San Onofre, July and Aug. 1976-78
W	Pages 41 and 71 of Reference (16) and page 42 of Reference (17)
X	Revised DES Table 8.1
Y	Revised DES Table 8.3
Z	Revised DES Figure 3.5

AA	Reference	(1)
BB	"	(12)
CC	"	(13)
DD	"	(14)
EE	"	(18)

COMMENTS

BY

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

ON THE

DRAFT ENVIRONMENTAL STATEMENT

RELATED TO THE OPERATION OF

SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3

DOCKET NOS. 50-361 AND 50-362

PREPARED BY THE

U. S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

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INTRODUCTION

The Draft Environmental Statement (DES) has been reviewed by the Southern California Edison Company and the San Diego Gas & Electric Company (hereinafter referred to as Applicants).

Comments resulting from this review are to identify inaccuracies in the data or discussion and provide clarification or correction. The comments follow the organization and numbering in the DES and should be read in conjunction with the referenced section.

SUMMARY AND CONCLUSIONS

Comment A-1

(page iii, item 2)

The DES states, "Each unit will produce up to 3410 MWe and a net electrical output of 1057 MWe".

It should be noted that 1057 MWe as stated in the applicants' ER-OLS* and in the DES was calculated using the Turbine-Generator (T-G) manufacturer's guaranteed output of 1127 MWe, which corresponds to an NSSS output of 3266 MWe, and an estimated in-plant consumption of 70 MWe.

However, when the NSSS is operating at 3410 MWe, and the T-G is at the wide-open valve condition (normal operating condition) the T-G output will be 1181 MWe. Current estimates of in-plant consumption have been revised to 75 MWe. Therefore, it is suggested that the net electrical output value be expressed as being in the range of 1052 MWe to 1106 MWe per unit when the NSSS is operating in the 3266 MWe to 3410 MWe range respectively.

*ER-OLS will be revised to reflect the range of 1052 MWe to 1106 MWe output per unit, in a future amendment.

Comment A-2

(page iii, item 3a)

The applicants do not agree with the conclusion reached by the staff on the possible destruction of at least a portion of the San Onofre kelp bed as a result of the thermal discharge from San Onofre Nuclear Generating Station. The assessment of impacts to the aquatic environment is invalid because of the use of inappropriate data from the staff's numerical model. A reassessment of the impacts is needed using ambient temperatures from actual field data. Actual field data are appended to these comments. Using appropriate ambient temperatures in the assessment, the excess temperature from thermal plume predictions made by either the applicants or staff will not create adverse effects on the San Onofre kelp bed. (Attachment T)

Comment A-3

(page iv, item 6(B)(2))

The preoperational monitoring program outlined in Section 6 goes beyond the applicants' program approved by the NRC by letter dated July 6, 1978, and is apparently based on inappropriate predictions of impact to the San Onofre kelp bed. The operational monitoring program outlined in Section 6 is an extension of the preoperational monitoring program. The operational environmental monitoring programs are under development for Units 2 and 3 Environmental Technical Specifications (ETS) and will be submitted in the near future.

1. INTRODUCTION

1.1 HISTORY

Comment 1-1

(page 1-1, paragraph 2)

The net electrical output for each unit is in the range of 1052 to 1106 MWe. Refer to Comment A-1 for discussion.

2.4 METEOROLOGY

2.4.4 Atmospheric dispersion

Comment 2-1

(page 2-8)

The DES indicates that the onshore tracer test conducted by SCE substantiates the acceptability of data measured on the San Onofre onsite (bluff) tower for use in calculating atmospheric dispersion. However, the DES does not consider the enhanced dispersion estimates derived from the onshore tracer test results. Consideration should be given to the enhanced dispersion estimates derived from the onshore tracer test results.

2.5 SITE ECOLOGY

2.5.2 Aquatic ecology

Comment 2-2

(page 2-9)

Oceanographic data reports from the past have incorrect consultant sources referenced. The first source in the list of three sources should be:

"(1) a thermal effects study performed jointly by Environmental Quality Analysts, Inc. and Marine Biological Consultants, Inc. in 1973 using data and results obtained from 1964-1972 by Bendix Marine Advisors, Inc., and Intersea Research Corporation."

3.2 DESIGN AND OTHER SIGNIFICANT CHANGES

3.2.1 Plant water use

Comment 3-1

(page 3-1, paragraph 2)

Delete the words, "makeup to," in the second sentence.

Comment 3-2

(page 3-1, paragraph 3)

The word, "makeup" should be corrected to "cooling," in the second sentence.

Comment 3-3

(page 3-1, paragraphs 2 and 3)

In the discussion of plant water use, the flushing of traveling bars and screens is incorrectly described. Seawater will be used for the flushing of the traveling bars and screens, not fresh water.

3.2.2 Heat dissipation system

Comment 3-4

(page 3-1)

The discussion should also include a description of the Seismic Category I Auxiliary Intake Structure of the circulating water system. The description of this design change can be found in Section 3.4.1 of the ER-OLS and Section 9.2.5 of the FSAR.

Comment 3-5

(page 3-1, paragraphs 4 and 5)

The seawater used for "cooling" has been incorrectly labeled "makeup." This error appears in the second sentence of paragraph 4 and the first sentence of paragraph 5.

Comment 3-6

(page 3-1, paragraphs 5 and 6)

The word "screenwell" should refer to the intake screenwell structure shown in Figure 3.3 and not the traveling screens. Lines 6 and 7 of paragraph 5 use "screenwells" where "traveling bars and screens" are being described. Also, in the second sentence of paragraph 6 "screenwells" is used instead of "traveling screens" and should be corrected.

Comment 3-7

(page 3-3, Fig. 3.2)

Figure 3.2 has been revised by the applicants to include the design details of the Auxiliary Intake Structure (Comment 3-4) and show the elimination of the manhole on the velocity cap. The revised figure can be found in Section 3.4 of the ER-OLS, Figure 3.4-2.

Comment 3-8

(page 3-5, paragraph 1)

The seawater used for "cooling" has been incorrectly labeled "makeup." This error occurs on lines 2 and 5, and should be corrected.

Comment 3-9

(page 3-5, paragraph 1)

The third sentence should read:
"To achieve the temperature required to control biofouling each unit has a recirculation and crossover gate."

2.3.1 Liquid Radioactive Waste Treatment System

Comment 3-10

(page 3-7, paragraph 7)

The flashed steam is routed to the "third point heater", not the "main condenser hotwell".

Comment 3-11

(page 3-8, Fig. 3.5)

The figure should be changed to reflect the correction identified in Comment 3-10. See revised Fig. 3.5 (Attachment Z).

Comment 3-12

(page 3-11, line 1)

The discussion on steam generator blowdown is incorrect. There are two steam generators for each unit, not four.

Comment 3-13

(page 3-13)

The discussion on the containment ventilation system should include a description of the 2,000 cfm mini-purge system. The description of this design change can be found in Section 9.4.1 of the FSAR.

2.4.1 Chemical Effluents

Comment 3-14

(page 3-16, paragraph 1, line 4)

The statement, "maintain a clean circulating water system," should be changed to read, "maintain a clean condenser system."

Comment 3-15

(page 3-16, paragraph 3, line 11)

The applicants will use a nitrite base compound or potassium chromate (K_2CrO_4) as the corrosion inhibitor for the turbine and component cooling water system. The statement in line 11, "will be treated with Nalco 39 to inhibit corrosion," should be changed to read, "will be treated with a nitrite based compound or potassium chromate to inhibit corrosion."

3.2.5 Transmission Lines

3.2.5.1 SCE Transmission Lines

Comment 3-16

(page 3-19, line 3)

The reference number for the description of retrofitting should be "4" not "1."

Comment 3-17

(page 3-20, Fig. 3.9)

An additional note should be added to the figure as follows:

> "The drawing depicts the four-circuit structure that will be used by SCE. SDG&E will use a similar structure with five circuits."

3.2.5.2 SDG&E Transmission Lines

Comment 3-18

(page 3-20, paragraph 1)

In the discussion of SDG&E's transmission lines, Talega Substation has been misspelled consistently throughout.

3.2.6 Probable Maximum Flood Berm

Comment 3-19

(page 3-23, line 1)

The reference number for the letter to the NRC should be "5" not "4."

5. ENVIRONMENTAL EFFECTS OF STATION OPERATION

5.3 IMPACTS ON WATER USE

5.3.1 Thermal discharges

General Comment Concerning Section 5.3

Applicants and the NRC both have evaluated the thermal effects of the diffuser system proposed for SONGS 2&3. The applicants applied a physical hydraulic model study. The NRC staff applied a depth-averaged numerical model. Applicants' model predicts compliance with all state and federal water quality requirements. The NRC Staff model predicts similar compliance for all realistic conditions but predicts potential violations of state thermal regulations for certain admittedly unrealistic conditions.

For reasons inherent in the input and methodology of the NRC staff model, applicants do not consider the staff's predictions to be valid. Further, applicants' model does not predict violations of the State Thermal Plan even under the unrealistic conditions postulated by NRC staff. Specific comments on DES Section 5.3 are discussed below:

A-19

5.3.1.1 Applicant's thermal analysis

Comment 5-1

(page 5-1, paragraph 6)

In the discussion of the physical model, the temperature difference of the discharged water is reported to be 30°F higher than the surrounding water. The 30°F delta T was necessary to achieve dynamically correct scaling of the actual delta T of 20°F and this fact should be mentioned in the discussion to avoid confusion.

Comment 5-2

(page 5-2, paragraph 3)

The statements are made, "The staff has reviewed the applicant's thermal analysis and believes that the physical model does not adequately represent certain hydrodynamic mechanisms and certain physical features of the prototype. The most significant of these is the limitation of the duration of the simulation by the size of the model basin." and "In fact, for the conditions represented in Figure 5.3,

an increase in simulation time would likely have resulted in predicted excess temperatures that violate state thermal standards." The applicants do not agree with these statements. The assumption that the size of the model basin limits the ability of the model in terms of representing valid results for longer time duration conditions are not considered to be valid. The conditions represented in DES Figure 5.3 represent a worst case condition and it is illustrated in the following paragraph that equilibrium had already been reached. An increase in simulation time would not have changed the predicted results.

In Figure 6.14, page 61 of Reference (5) (Attachment A) it is shown that for the circumstances represented in the DES Fig. 5.3, the hydraulic model had clearly reached an equilibrium peak temperature. The prototype period of time represented in this hydraulic model test of a zero drift situation is in excess of 30 hours of continuous operation at full load. Referring to Attachment A it can be seen that the peak temperature measured in the hydraulic model basin (the upper curve) quickly reaches an equilibrium level in a time of approximately 12 prototype hours. For the subsequent 18 hours of operation at zero drift velocity, the only variation in temperature is that associated with the experimental fluctuations. The behavior is similar for the lower curve, which is the peak temperature measured at a distance equivalent to anywhere beyond 1000 ft. from the point of discharge.

The results given in Attachment A, and the detailed error analysis performed in Reference (5), show quite clearly that there is no basis for the assertion that the hydraulic simulation represented in Fig. 5.3 of the DES, if continued, would lead to a violation of the state thermal standards. To the contrary, it is clear that in a no-drift situation an equilibrium peak temperature of 2.3°F (beyond 1000 ft.) would be reached within about 12 hours and this peak temperature would not be exceeded for longer durations.

The DES further states, "Once the thermal plume reaches a lateral boundary of the tank, the simulation must be terminated. The length of the simulation is thus dictated by the size of the model basin rather than by the natural time scales of the problem."

The tests do not have to stop when the thermal plume reaches a boundary because a large prototype area is represented by the model basin and the maximum temperatures are close to the diffusers. Furthermore, the natural time scale of the problem is that associated with the initial jet mixing and establishment of the steady induced offshore drift of the

thermal field. The time scale associated with the establishment of steady state conditions in the model was found to be 12 hours at the most. The size of the basin does not limit the results until more than 40 hours, as shown in Attachment A. It is also confirmed by the results given in Figures 6.29 and 6.34, pages 76 and 81 of Reference (5) (Attachments B and C). The results shown are for a situation where the hydraulic model was operated for the accelerating current pattern given on Attachment B. The outcome of the model is shown in Attachment C. It can be seen that the peak temperature rapidly reduces as the current velocity increases, showing that the natural time scale or response time is only a few hours. Indeed, it is because of the short time scales of the problem that the hydraulic model is appropriate.

The reason for the short time scale can be seen in Figure A-7, page A-15, of Reference (5) (Attachment D) and in Figure 6.8, page 47, of Reference (5) (Attachment E) which both clearly show a surface layer of warm water overlying a cooler bottom layer. The diluting water for the discharge jets is always drawn from this cooler bottom layer so the dilution is fixed by the rate of supply of bottom water. When there is no drift the bottom flow is generated by the jet entrainment. When an ambient current is present the flow of diluting water is even greater so the peak temperatures are reduced.

A-20

Comment 5-3

(page 5-2, paragraph 4)

The DES states, "Although the problem of underprediction is inherent in all the applicant's results, it is less significant for the realistic cases." It cannot be concluded that the hydraulic model consistently underpredicts delta T's with respect to what will really occur; rather, the only conclusion that can be drawn is that the math model gives consistently higher values than the physical model.

The basic hydraulic model report (Reference (5)) discusses possible errors in hydraulic modeling and deduces a laboratory target value of 2.5°F so that all possible errors will be included within the 4°F limit; but the report does not imply that there is an expected bias in the results as the errors could as well be negative as positive.

5.3.1.2 Staff's thermal analysis

Comment 5-4

(pages 5-3, 5-4, and Fig. 5.6)

Atmospheric data purported to be typical of July are used in the NRC mathematical model to predict ocean temperatures. Specifically, air temperatures with a maximum of approximately 82°F and a minimum of 65°F were used in the model (see DES Fig. 5.6, page 5-7).

Actual field data measured at coastal sites in Southern California for July show mean daily maxima and mean daily minima substantially lower than these temperatures. In addition, temperature summaries for the San Onofre site presented in Table 2.3-6 of the FSAR and Table 2.3.2-4 of the Applicants' Environmental Report OL Stage show mean daily maxima and mean daily minima temperatures on the order of 67°F and 61°F respectively.

Published U.S. Climatological Data for July 1975, 1976, 1977, 1978 (Attachments F, G, H and I) give temperatures for two coastal stations (Newport Beach Harbor and Santa Monica Pier). Data at San Onofre are from the meteorological tower maintained at the site: (Attachment J).

Actual Air Temperatures For The Month Of July

	Newport Beach Harbor mean daily		Santa Monica Pier mean daily		San Onofre mean daily	
	max	min	max	min	max	min
1975	69.8°F	62.1°F	68.0°F	61.5°F	66.6°F	59.5°F
1976	72.4°F	64.4°F	71.1°F	63.5°F	67.6°F	63.3°F
1977	70.7°F	61.4°F	67.9°F	61.2°F	67.5 F	61.5°F
1978	70.7°F	62.0°F	68.1°F	59.8°F	67.5 F	61.2°F

The indication is clear that a typical July daily atmospheric maximum temperature at San Onofre should be in the order of 68°F with a typical minimum of about 61°F.

These atmospheric data are an important feature of the numerical model since high air temperatures will lead to high ambient water temperatures being produced by the numerical model in the inshore region. An indication that this has in fact occurred, are the water temperatures used in Section 5.4 (in the benthic section ambient depth-averaged temperatures of 27.8°C (82°F) and in the kelp section ambient bottom temperatures of 21.5-24°C (71-75°F)). These temperatures are considerably higher than have actually been measured in the field (References (8),(22) and (23)). High ambient water temperatures in the inshore region will, in turn, be reflected as high temperature increments offshore due to the inshore water being transported offshore by the net offshore drift produced by the diffusers. It is quite likely that these features of the numerical model could be responsible for the possible temperature excess violations predicted by the staff's numerical modeling.

Comment 5-5

(page 5-4, paragraph 2)

The DES omits computed ambient temperature maps (without heated water discharge) and computed temperature maps with thermal discharge from which the delta T maps were derived as presented in DES Figures 5.8, 5.10, 5.12, 5.14, 5.16, 5.18, 5.20, 5.22. DES Section 5.4, environmental impacts, refers to this section (5.3.1) and discusses absolute values of ambient temperatures.

Since the basis for the prediction of temperature excess associated with the operation of SONGS Units 2 and 3 is the difference between the numerically predicted temperature distributions for operating and ambient conditions, these temperature maps should be made available to the applicants for evaluation and interpretation, or included in the FES. In addition, these temperature maps are essential to the assessment of impacts on marine life and necessary to provide the basis for much of DES Section 5.4.

Comment 5-6

(page 5-7, paragraph 2)

The DES states, "The net downcoast drift used for these simulations is based on limited data for mid-July. During other times of the year, the data indicate that an absense of drift can persist for up to several days. Although there are no data to confirm a no-drift assumption during mid-July, the staff believes that this situation is at least possible, and therefore, should be considered." Applicants disagree with the assumpation that a no-drift situation is possible.

Current data analyses have been previously supplied to NRC (References (3) and (4)). In Reference (3), pages 59 and 60, it was concluded that current speeds are higher in summer than in winter and that, during winter, periods of very low currents could exist lasting a few days, but that tracks indicated no evidence of currents with no net transport during this period. The available current record for summer, published in Reference (3), shows no evidence of any period of no net drift.

In Reference (4) more recent data obtained by Winant and Severance for the Marine Review Committee were analyzed. These data were collected using a newer type of current meter less susceptible to clogging than the meters used for the data previously analyzed (obtained from Intersea Research Corporation). Reference (4) makes it clear that at no time in the current meter records are there data to indicate that there is a period of zero drift. In fact, the records indicate a substantial drift either upcoast or downcoast with a speed of the order of 0.1 to 0.2 knots (5-10 cms/sec). The data therefore confirm the drogue and current meter data initially obtained by Intersea Research Corporation (IRC). The data appear to indicate that in fact IRC's meters may have been underrecording the magnitude of the currents.

In the past year (1978) more data have been collected at Del Mar (15 miles downcoast from San Onofre) by Winant of Scripps Institution of Oceanography and also at San Onofre by Brown and Caldwell Engineers under contract to the Marine Review Committee of the California Coastal Commission. Winant's data (Attachment K) show substantial longshore currents always occur at Del Mar. The Brown and Caldwell data obtained at the San Onofre site appear to be well correlated with the Del Mar data and also indicate strong drift currents either upcoast or downcoast for periods of several days. The change in direction is always a rapid process. These most recent data further corroborate the previous conclusion that there exist no periods of zero drift (Attachment L). A zero drift period is not considered to be credible, and should not be postulated for evaluating compliance with the state thermal requirements.

Comment 5-7

(page 5-7, paragraph 3)

The DES states, "Although the thermal numerical model is depth-averaged, it is still possible to address the state standards with model results because the buoyancy and shear generated by the diffuser discharge produce a hydrodynamic instability, resulting in the water column's being well mixed within several diffuser lengths of the discharge[8]. Therefore, within the specified mixing zone, the depth-averaged predictions are reasonable representations of surface temperatures."

Reference 8. C. W. Almquist and K. D. Stolzenbach, Staged Diffusers in Shallow Water, Report No. 213, Ralph M. Parsons Laboratory for Water Resources and Hydrodynamics, Massachusetts Institute of Technology, Cambridge, Massachusetts, 1976.

Referring to pages 103-106 of DES Reference 8 (Attachment M) it is clear that the hydrodynamic instability claimed as the basis for application of depth-averaged numerical modeling definitely will not occur with the San Onofre diffusers. It is therefore evident that depth-averaged modeling is inappropriate to the San Onofre configuration so that drawing conclusions about violation of the California thermal standards on the basis of the results of such a model is not valid. It cannot be concluded that depth-averaged predictions are reasonable representations of surface temperatures. For the same reasons, the bottom temperatures cannot be predicted correctly from the NRC depth-averaged numerical model.

Comment 5-8

(page 5-7, paragraph 4)

The DES states that, "The model numerical is inadequate for addressing the issue of bottom temperature. However, at worst, the 4°F excess temperature should only touch the bottom over a very limited area in the vicinity of the Unit 2 and 3 diffusers."

The applicants agree that the numerical model is inadequate for addressing the bottom temperature issue as noted above. In view of the staff's admission of this inadequacy there is no basis for the staff's statement concerning the 4°F excess bottom temperatures. In the assessment of San Onofre 2&3 diffuser plume extent, Figures 1, 2 and 3 have been formulated from Reference (5) (Attachments N, O and P). These show hydraulic modeling results in the horizontal and vertical and with respect to the San Onofre kelp bed area under conditions of no ambient currents, and two typically encountered downcoast ambient currents.

It should be noted that the vertical profiles in Figures 1, 2 and 3 (Attachments N, O and P) stop at a depth of 35 feet but the actual bottom depth is deeper. These figures show no indication of impingment of a 4°F isotherm on the bottom or even present in the water column.

Figure A-7 (Attachment D) shows an actual vertical cross-section of the modeling results from surface to bottom along the centerline of the San Onofre 2 & 3 diffusers. This figure shows that the thermal plume does not impinge substantially anywhere on the bottom and that a temperature increase of 0.4°C (0.8°F) is not exceeded on the bottom.

Comment 5-9

(pages 5-2 through 5-24)

The DES omits any reference to error analysis for either applicants' hydraulic modeling or the staff's numerical modeling. Such an analysis is essential in determining the bounds within which the results are accurate or applicable.

The applicants' modeling has been subjected to a comprehensive error analysis, Reference (7), which discussed possible sources of error and determined appropriate error margins. This error analysis should be referenced in the DES.

There is no discussion of errors for the staff's math model. As with all math models, various assumptions and coefficients are necessary and the results must be viewed with consideration of the potential error inherent in the model. It is a particular concern with this math model which appears to be deficient in representing the real phenomenon occurring, specifically two-layer stratified shear flow and individual jet mixing. Because of this, the range of possible error for the math model is considered to be greater than for the hydraulic model. An error analysis for the staff's math model should be presented, or at least referenced and made available to the applicants.

Comment 5-10

(page 5-7, paragraph 5)
(page 5-24, paragraph 1)

The DES states, "In the absence of drift, the 4°F excess temperature will not reach the shore. However, state thermal standards would be violated since the 4°F surface isotherm will extend beyond the 1000 ft. radius during most of the tidal cycle. The staff concludes that although there exists a remote possibility that state thermal standards could be violated by the operation of Units 2 and 3, violations would, at worst, be infrequent and for short periods. There is no evidence in available drift data to indicate that such an occurrence would take place during the summer when thermal impacts would be the most severe."

The applicants do not agree that the state thermal standards limitation for the 4°F surface isotherm beyond 1000 ft. for more than one half of a tidal cycle will be violated in the absence of drift or under any other circumstance. The applicants' thermal modeling studies addressed a no-drift condition, showing no violation of state thermal standards (DES Figure 5.3). It is the position of the applicants that the mathematical model predictions are excessively high, mainly as a result of inappropriate inputs and assumptions. The staff selected inputs include air temperatures that are about 10°F too high (see Comment 5-4), unsubstantiated two day no-drift conditions along the open coast at San Onofre in July (see Comment 5-6), and modeled ambient depth average water temperatures that are higher than ever recorded in the area's field data (see Comment 5-8). Also, such violations predicted (as remote) by the staff are derived from output of their mathematical model when the model itself could be approaching its limits of validity. Yet, this can not be proven, mainly because an error analysis that would substantiate the claimed applicability of the numerical model is not included in the DES (see Comment 5-9).

For these reasons, the staff's conclusion, that even a remote possibility of a violation of the state thermal standard exists, cannot be justified on a technical basis.

5.4 ENVIRONMENTAL IMPACTS

5.4.1 Terrestrial environment

Comment 5-11

(page 5-24)

The discussion on environmental impacts to the terrestrial environment should also include an assessment of the Probable Maximum Flood (PMF) berm. The applicants submitted an environmental assessment of the PMF berm, by letter dated February 14, 1978. The assessment indicated that the PMF berm should have no adverse environmental impact on the terrestrial ecological characteristics.

5.4.2 Impacts on the aquatic environment

5.4.2.1 Effects of the heat dissipation system

Thermal effects

Comment 5-12

(page 5-24, paragraph 8)

The discussion of the proposed heat treatment states, "the applicant proposes to heat treat portions of the intake system to remove biological growth (Sect. 3.2.2)." This statement is incomplete since the applicants also propose to heat treat the discharge system. The text should be changed to reflect this point.

Comment 5-13

(page 5-25, paragraph 2)

While the applicants do not agree that the area to be affected by thermal discharges will be greater than previously thought, the applicants do concur that even assuming a larger plume, the impact to the aquatic environment is expected to be minimal and of an acceptable nature.

Fish

Comment 5-14

(page 5-25, paragraph 5)

The applicants agree that cold kills of fish are not likely to occur, but for the reason that the extent of the thermal plume is relatively small, and the difference between the ambient and the induced temperatures is less than the rapid temperature changes that occur naturally.

Comment 5-15

(page 5-25, paragraph 4)

It is stated that, "However, with more area to be influenced by the effluent, more fish potentially will be affected."

This appears to be an oversimplification since the thermal plume will not be uniformly distributed with depth but rather the more buoyant heated water will be on the surface with the bottom water remaining unaffected. This means that an increase in the surface area of the plume would only effect fish species which inhabit the upper water column and no additional effect would be expected for fish associated with the bottom. Fish are not uniformly distributed within the water column and actually exhibit a distribution opposite to that of the thermal plume, that is with a greater concentration of fish associated with the bottom and fewer fish associated with the surface. During the 1976 ETS studies a comparison of surface versus bottom gill net data showed that 88% of the fish were found on the bottom and only 12% in the surface waters. Therefore, the area potentially effected by a larger plume would be only the surface waters, which have a relatively small percentage of the total fish abundance.

Benthic fauna

Comment 5-16

(page 5-25, paragraph 8)
(page 5-26, paragraph 1)

In the discussion of DES reference 11 (Ford, et al., 1976), it is not made clear that effects upon growth and mortality of *S. franciscanus*, *P. ochraceus* and *R. poulsoni* occurred only in the experiment simulating a location 84 meters from the discharge and not at 335 m away.

The applicants recommend that clarification be added to these paragraphs in order that the reader be clearly informed that the effects discussed in the DES were limited to the simulation of the 84 location meter distant from the point of discharge.

Benthic fauna

Comment 5-17

(page 5-26, paragraph 2)

Ambient water temperatures in DES Section 5.3.1 are referenced here but no ambient temperatures are included in that section. As previously noted, in Comment 5-5, maps of these ambient temperatures should be presented.

The ambient temperatures used in the discussion of the assessment of benthic fauna are apparently taken from the staff's mathematical model. The ambient temperatures used are clearly too high, as example, "temperatures potentially as high as 27.8°C (82°F) may occur naturally,..." This is far in excess of actual measurement of natural ambient water for the area.

The maximum surface water temperature reported in the vicinity of San Onofre is approximately 23°C (References (8),(22), (23), (16) and (17)). Mean San Onofre natural surface temperatures for July and August of the past three years are on the order of 19°C and the corresponding bottom temperatures are about 17°C.

University of California Scripps Institution of Oceanography (SIO) data reports entitled "Surface Water Temperatures at Shore Stations - United States West Coast" give mean surface water temperatures at San Clemente pier, five miles North of San Onofre, References (16) and (17)):

Mean Surface water Temperatures at San Clemente

	July	August	September
1977	18.27	20.48	18.53°C
1976	19.59	17.95	19.77
1975	18.58	17.01	17.91
3 year mean	18.8	18.5	18.7°C

With surface temperatures in the 18-19°C range it should further be noted (for benthic assessment) that corresponding bottom temperatures will be even lower: all San Onofre field data support the existence of vertical temperature stratification in depths greater than about 30 feet when surface temperatures are in this range. (see Attachment T).

Comment 5-18

(page 5-26, paragraph 3)

The DES states, "On the basis of the 1977 study[11] the staff concludes that several components of the benthic fauna in the vicinity of SONGS would probably be adversely affected in areas where weekly mean temperatures of 22°C prevail for

one month or more or where daily temperatures reach or exceed 24°C. It is not, however, anticipated that temperatures averaging 22°C will occur for more than 2 to 3 weeks or that the areas experiencing temperatures of 24°C or greater as a result of SONGS operation will be considerably larger than the area experiencing these temperatures under natural conditions."

Based upon historical temperature records between 1975 and 1978 (References (8),(22) and (23)) the use of weekly mean bottom temperatures of 22°C appears to be inappropriate and should be lowered to 17°C.

The applicants recommend, therefore, that the sentence indicating 22°C weekly mean temperature could exist on the bottom for 2 to 3 weeks be changed and that a summary sentence be added to indicate that the components of the benthic fauna previously discussed will not be adversely affected.

Also, the date of DES reference 11 (Ford, et. al.) is 1976, not 1977, as stated in the first sentence of the paragraph.

Kelp

Comment 5-19

(page 5-26, paragraph 5)

The DES states, "Although this deterioration may have been partially a result of overharvesting, much of it is probably caused by the increased alteration of the near-shore environment by human activities. In particular increased temperatures and increased turbidity have been shown to be inimical to kelp survival."

The thermal effects on kelp cited in Phillips (1974) were for naturally occurring events and not as induced by human activities. Man induced thermal effects on kelp have not been demonstrated.

The turbidity comment by Phillips (1974)(Reference (15)) was in reference to work conducted by North (1960)(Reference (12)) on effects of sewage outfalls on kelp health. The type of turbidity generated by a sewage outfall is not equivalent to the surface turbidity which may be associated with a cooling water discharge.

It is recommended that the discussion be changed to reflect that the deterioration may have been partially a result of overharvesting, much of it is probably caused by increased alteration of the near-shore environment by human activities,

in particular, sewage treatment facilities and industrial/ chemical discharges. The toxic element of each discharge has not been isolated to date, i.e., heavy metals, sedimentation, oils, turbidity, etc.

Comment 5-20

(page 5-26, paragraph 6)

The DES states, "Typically, canopy tissue deteriorates during the warmest time of the year leaving the basal portion of the plant (which is in cooler water) for regeneration when temperature and light conditions permit."

It has been documented that kelp deterioration occasionally occurs when (apparently) surface temperatures exceed critical thermal limits. However, it appears that seasonal kelp deterioration may be due to synergistic effects and not just to a thermal component. In the open coast setting, an inverse relation often occurs between temperature and dissolved nutrients. As the temperature increases, the nutrient content often decreases, to or perhaps below levels critical to kelp. Additionally, the highest nutrient concentration is found on the bottom near the basal tissues and the lowest concentration near the surface where most kelp deterioration occurs (Reference (2)).

Other evidence (Reference (13)) implies that when Macrocystis pyrifera is placed in a bay, which are typically much higher in nutrients than found in the open coast, the kelp remains in the healthy state even when the entire plant is subjected to 25-26°C (77-79°F) for extended periods.

At this time, it is not known clearly if temperature, nutrients, and/or other unknown components of the water contribute the most to kelp deterioration. However,there is a possibility of a beneficial effect from Units 2 & 3 operation if outfall upwelling creates a surface nutrient plume that will occasionally come in contact with kelp plants during the warm water months.

It is recommended that the DES be changed to reflect the fact that typically, canopy tissue deteriorates during the warmest time of the year leaving the basal portion of the plant (which is in the cooler water) for regeneration when temperature and light conditions permit; and that reduced surface nutrients and higher bottom nutrient concentrations may contribute to canopy deterioration and basal tissue regeneration, respectively (Reference (2)).

Comment 5-21

(page 5-26, paragraph 7)

The DES states, "It is estimated that the larval, juvenile, and adult stages of 25 main sport fish use kelp beds for refuge and food gathering (eating the associated invertebrates, the kelp itself, or other algae) and the average standing crop of fish is estimated to be 300 kg/ha (300 pounds per acre)."

For many years it was believed that the kelp beds, especially the canopy region, represented spawning and nursery grounds of many sport and forage fish (Reference (1)). No evidence is available to support the therory that the canopy is widely used as a spawning area (Reference (6)). Larvae of a few fishes are found in greater abundance in kelp beds than elsewhere. These include the topsmelt, kelp goby, kelp clingfish and striped kelpfish (Reference (1)); species not considered important sport fish.

Many juvenile fishes inhabit the kelp canopy. However, those of recreational or commercial value are found to be more numerous in rocky areas away from kelp, i.e., kelp bass. The only common juvenile fish that are reported to be at higher concentrations within kelp beds are kelp surfperch, kelp pipefish and kelp clingfish (Reference (1)).

Only one adult species, the kelp clingfish, is considered to be obligate to kelp plants. All other fish species will persist in the environment with or without kelp plants present. Diversity of fish species is not altered significantly by the presence or absence of kelp. A highly varied bottom topography appears to be the most important factor for extensive fish-life and to be of greater significance in this respect than kelp (Reference (14)).

The DES should be changed to reflect the fact the kelp beds do not appear to be spawning grounds, rearing grounds, or refuge areas for recreationally or commercially important fish species (Reference (1) and (14)). Only the kelp clingfish appears to be obligate to kelp beds for survival.

Comments 5-22

(page 5-26, paragraph 8)

The DES states, "Kelp is an important commercial commodity ...harvested yearly at a landed value of $2 million."

The commercial value of kelp is well documented, although, a kelp bed is only considered commercially important when it has: high stand density, extensive areal coverage and close proximity to a commercial harbor. The San Onofre kelp bed does not now nor has it ever met these criteria because of the limited extent of substrate suitable for attachment. The DES should be revised to reflect the fact that the kelp beds in the vicinity of San Onofre are not commercially harvested.

Comment 5-23

(page 5-27, paragraph 2)

The DES states, "It has been rather well established that temperatures above 18-20°C (64-68°F) cause deterioration of kelp, and the degree of degradation is directly related to the duration of exposure to these temperatures. Increased surface temperatures caused by SONGS operation (all three units) would have the effect of extending the period of canopy absence. During the hottest time of the year, data in Section 5.3.1 suggests that the closest kelp bed (San Onofre bed) will experience an average surface temperature increase (over a 24-hour period) of 1.4°C (2.6°F); the range of temperature increase will be 0.6-2.2°C (1-4°F)."

The statement in Reference (15), of 18-20°C (64-68°F) thermal exposure causing kelp deterioration was based on comments made in Reference (12), which refers to the colder water variety of kelp found near Monterey, California. For kelp plants located in southern California waters, the critical thermal maximum is more in the range of 20-22°C (68-72°F) (Reference (21)).

During the warm water months of the year, data in Section 5.3.1 suggests that the closest kelp bed (San Onofre bed) will experience average surface water temperatures increases due to the operation of SONGS of less than 0.6°C (1°F); the range of temperature is 0-0.9°C (0-1.5°F).

Temperatures taken in the vicinity of San Onofre between July and September over a three year period show a range of averages of 18.5 to 18.8°C (65.3-65.8°F) for the surface waters (References (16) and (17)). Clearly, the predicted maximum temperature increase of 0.9°C from plant operation when added to the ambient temperature in the vicinity of San Onofre of 18.8 C will not exceed the critical thermal limits established by North. The DES should be revised to reflect this fact.

Comment 5-24

(page 5-27, paragraph 3)

The DES states, "Although daily natural temperature variations of 1°C (2°F) are not uncommon in the area (ER page 2.2-28) they would not be continuous in nature and would thus not affect the bed as severely as the continuous SONGS discharges would. Prediction of the degree to which canopy disappearance would be prolonged is impossible. Regeneration would be quicker in years with naturally cooler ocean temperatures, assuming the regenerative tissues remain unaffected (see below)."

The operation of SONGS 1, 2, and 3 will not have a continuous effect on the San Onofre kelp bed. Power plant thermal discharges will contribute no more than 0.9°C surface temperature increases to the kelp bed and thus will only occur with downcoast currents. The more recent current meter data, as discussed in Comment 5-6 must be considered in regard to this kelp section. It is seen from these data that summer upcoast currents, which would result in no kelp bed plume impingement, occur during approximately half of the summer season. Further, the increase in temperature will be dependent on the strength and duration of the current. Increased surface temperatures due to the operation of SONGS 1, 2 and 3 will always be less than the measured natural surface temperature variations of the area, and will be sporadic.

The staff is requested to revise the DES to reflect the fact that increased nutrients brought to the kelp bed surface waters by outfall induced upwelling may help resist the natural seasonal canopy deterioration and provide beneficial effects from station operation when an outfall induced nutrient plume drifts over the kelp bed during warm water months.

Comments 5-25

(page 5-27, paragraph 4)

The DES shows ambient bottom temperatures in July reaching as high as 23-24°C (74-76°F) with temperature of 22-23°C (72°F and 73°F) for a week at a time. These temperatures are the outcome of the staff mathematical model (DES Section 5.3.1) and are an inaccurate representation of existing natural conditions occurring at San Onofre. Applicants' Comment 5-17 suggests that a bottom temperature of 17°C (63°F) is a more realistic representation.

Also, this section references DES Section 5.3.1 as a basis for a typical bottom temperature range of up to 19°C (66°F) in August and September, however, these referenced temperatures are not found in DES Section 5.3.1. Such a temperature appears to represent more adequately the extreme or high end of the range of summer bottom temperatures at San Onofre. As indicated above, an appropriate representation of a monthly or weekly mean bottom temperature would be 17°C (63°F).

Comment 5-26

(page 5-27, paragraph 4)

The DES states, "...a several week period could exist in which temperatures exceed 19°C."

Results of the applicants' thermal analysis demonstrates that the temperature increase at the bottom in the San Onofre kelp bed will be much less than 0.6°C (1°F) under any current condition. Under most conditions it is predicted that there will be no increase in bottom temperature in any portion of the kelp bed. Bottom temperatures measured at San Onofre during July and August over a three year period show a range of averages of 12-18°C (55-64°F). The addition of less than 0.6°C (1.0°F) to measured ambient temperatures should have no adverse effects to kelp basal tissues from which the canopy is regenerated annually.

Comment 5-27

(page 5-27, paragraph 5)

This paragraph summarizes the staff's conclusions that, based on assumed natural bottom temperatures of 21.5 - 24°C (71 - 75°F) and bottom temperature increases in the San Onofre kelp bed of 1 - 1.5°C (2 - 3°F) due to operation of Units 1, 2 & 3, damage to the kelp basal tissue might result if slack currents occur for several days. Further, if this scenerio occurs frequently, the bed might not recover fully, resulting in long term damage. While the staff admits this is unlikely, it recommends additional extensive monitoring of the San Onofre kelp bed.

It is the applicants' conclusion that an assessment based on appropriate ambient bottom temperatures (17°C or 63°F) derived from actual field data, and temperature increases recognizing that the thermal plume will be stratified (0.6°C/1.0°F maximum) will yield a conclusion that damage to basal tissues will not occur, even under worse case conditions. Also, there is no evidence to support the use of an assumption that a condition of several days of slack current will ever occur, or that it would occur frequently. The applicants believe that the proper conclusion to be drawn from the relevant data is that the operation of San Onofre Units 1, 2 & 3 will have no significant adverse effects on the San Onofre kelp bed.

The greatest adverse effect which could be expected is a slight prolongation of the natural summer surface canopy deterioration period which does not effect the basal tissues or the regeneration of the kelp in the fall.

Based on the above evaluation, the extensive monitoring recommended by the staff is not justified, and monitoring presently being accomplished is sufficient to assess potential effects of San Onofre Units 1, 2 & 3. Specific comments on the monitoring are contained in Comment 6-3.

5.4.2.1 Turbidity and Sediment Transport Effects

Comment 5-28

(page 5-27, paragraph 6)

The DES is deficient in that it fails to substantiate the assertion that larger thermal plumes directly imply larger turbid plumes.

Comment 5-29

(page 5-28, paragraph 1)

The DES states, "The effect on the kelp would potentially be decreased photosynthesis, possibly causing many of the plants to die if the exposure is continuous (a 1% increase in the absorption coefficient has been found to result in a 20% loss in net photosynthesis at 15m)[13] and burial of the holdfasts in particles which settle out, inhibiting regeneration and recolonization. Regardless of the magnitude of these effects, their presence would add to the probability that the kelp bed would be adversely affected (see preceding section)".

As discussed in Comment 5-24, the plume from SONGS 1, 2 and 3 will not have continuous contact with the San Onofre kelp bed.

Reductions in photosynthesis from power plant induced turbidity has not been demonstrated. The net reduction in photosynthesis referred to by Phillips (1974)(Reference (15)), was based on work by North (1958)(Reference (18)). The model (computation) was based on a uniform dispersal of light absorbtive material throughout the water column. This model was designed for the turbidity generated by a sewage outfall. For thermal diffusers, there would be an uneven distribution of natural turbidity and the equation does not apply.

Sewage outfalls generate a substantial amount of turbidity that is dispersed throughout the water column. A thermal outfall does not create turbidity, but rather, can occasionally redistribute portions of a naturally occurring dense bottom turbid layer to the surface. Therefore, there is no net gain in the amount of suspended matter in the water. The major effect is that the turbidity on such occasions can be seen on the surface. Further, the turbid plume characteristics sometimes experienced at Unit 1 should not be applied to Units 2 and 3.

A surface plume can be seen at Unit 1 when the surface waters are relatively clear and the bottom water is turbid. The intake and outfall withdraws and upwells, respectively, portions of the bottom turbid layer and pumps it to the surface. The bottom turbid layer qualitatively appears to be essentially a nearshore phenonemon that is generated from wave agitated bottom sediments. Units 2 and 3 outfalls are located in deeper and clearer ocean waters, although the intakes are at a depth comparable with Unit 1. It is predicted that on occasions when naturally occurring turbidity is present the Units 2 and 3 intakes will withdraw turbid bottom water like Unit 1, however, the Units 2 and 3 outfalls will be upwelling clearer bottom waters. Additionally, Units 2 and 3 effluent will be initially diffused through 63 ports each and then mixed with the receiving water at an estimated ratio of 10:1 (Unit 1 dilution ratio is approximately 3:1). Given the situation of clearer water at the outfalls and increased mixing of effluent, it is predicted that a turbid plume will not normally be detected.

In terms of effects, Unit 1 can be viewed as potentially creating more severe effects than Units 2 and 3, i.e., single port outfall and reduced mixing (3:1). The environmental evidence indicates that there is no adverse impact on benthic faunal or floral groups near the outfall. In fact, results from the Environmental Technical Specifications benthic program demonstrate that the fauna and flora near the Unit 1 outfall are more abundant than those from the control station (References (8), (9) and (10)).

No relationship has been established between a turbid plume and thermal plume. The factors that influence the intensity and extent of each constituent are different and may not be interrelated.

The applicants' conclusions are that a turbid plume emanating from Units 2 and 3 operation may occur under certain oceanographic conditions, however, it should be less intense than observed at Unit 1 because (1) of increased mixing of the discharge and (2) the diffusers are located in deeper, clearer waters. Environmental Technical Specifications benthos study results show that redistributing a natural turbid layer has no adverse effects on faunal and floral groups for Unit 1 (References (8), (9) and (10)). Therefore, no adverse effects on faunal or floral biota are predicted.

Entrainment

Comment 5-30

(page 5-29, paragraph 2)

The DES states, "The staff's analysis of entrainment effects in the FES-CP remains valid (FES-CP, p. 5-7 to 5-12). A program on the mortality experienced by entrained ichthyoplankton is being planned currently at SONGS 1 and is expected to be submitted to the NRC staff in December, 1978, for approval."

Refer to (applicants' Comment 6-5).

Impingement

Comment 5-31

(page 5-29, paragraph 4)

The DES states, "The majority of the fish impinged at SONGS 1 are anchovy,..."

A review of last three years (1975-1977) of ETS in-plant impingement monitoring reveals that the Queenfish, Seriphus politus has been the most predominant species impinged at Unit 1 in terms of both numbers and weight.

Entrainment of anchovy has been sporadic and shows occasional high numbers entrapped probably reflecting the schooling behavior of the species. Early impingement information (pre-ETS-1975) indicating high impingement of anchovy may have been biased by a combination of sampling frequency and these chance occurrences.

It is recommended that the word anchovy be replaced with "Queenfish" to reflect the most recent data available. This change does not effect the overall assessment result indicating no significant effect on recreational or commercial fishing resources.

Offshore Current Induction

Comment 5-32

(page 5-29 paragraph 5)

The applicants agree that there are no detrimental effects of induced circulation on the aquatic environment. However, the discussion of the analysis in the DES concerning the effects of the induced circulation on the aquatic environment should mention that the analysis is based on the diffuser design described in Section 3.4 of the ER-OLS and Section 9.2 of FSAR.

5.5 RADIOLOGICAL IMPACTS

Comment 5-33

(page 5-33, Table 5.4)

Table 5.4 of the DES shows calculated annual doses nearly a factor of 3 greater than the values provided by the applicants in Table 5.2-12 of the Environmental Report - Operating License Stage (ER-OLS). The doses shown in Table 5.2-12 of the ER-OLS were calculated using annual average meteorology.

It appears that the staff has used short term 15th percentile meteorology (valid only for purge releases instead of continuous long-term releases) in calculating the doses shown in Table 5.4 of the DES. The staff is requested to revise the doses consistent with Table 5.2-12 of the ER-OLS.

Comment 5-34

(page 5-34, Table 5.6)

Table 5.6 of the DES shows that the dilution factor used for the dispersion of liquid release is 1. However, Section 5.2.4.3 of the applicants' Environmental Report-Operating License Stage (ER-OLS) shows that the dilution factor is 10 between 0-10 miles and 12.5 between 10-50 miles. The values reported by the applicants were derived consistent with Regulatory Guide 1.112.

The staff is requested to revise the values in Table 5.6 of the DES to be consistent with the dilution factors shown in Section 5.2.4.3 of the ER-OLS.

5.6 SOCIOECONOMIC IMPACTS

5.6.1 Introduction

Comment 5-35

(page 5-40, paragraph 8)

The second sentence should read:

"The central portion of Orange County ...".

5.6.5 Impact on recreational resources

Comment 5-36

(page 5-44 and 5-45)

The NRC staff concludes in this section and other sections (5.6.5, 9.1, 10.5, and 10.7) of the Draft Environmental Statement (DES), that the applicants' current plan to restrict the public use of the beach in front of the San Onofre Nuclear Generating Station, within the exclusion area, is a significant cost of the project unanticipated at the issuance of the construction permit. Applicants disagree with the conclusion that there will be any significant loss of recreation area.

Subsequent to the issuance of the Final Environmental Statement (FES) required for the construction permits of SONGS 2 and 3, the ASLAB in its initial decision dated December 24, 1974 (ALAB-248) questioned whether recreational activities within portions of the exclusion area should be permitted, and the adequacy of the applicants' authority to control activities in the exclusion area. By Decision dated April 25, 1975 (ALAB-268) the ASLAB ruled that the applicants' authority to control activities within the exclusion area was insufficient and remanded the issue for further hearing.

On October 10, 1975, the applicants submitted Amendment No. 22 to the PSAR consisting of information concerning a proposal for a reduced exclusion area. Amendment No. 22 also provided estimates of the number of persons anticipated within the proposed reduced exclusion area. Applicants' experts estimated the maximum number of persons within the proposed reduced exclusion area would be 31.

The NRC Staff evaluated applicants' assessment of potential beach use as provided in Amendment No. 22 to the PSAR and concluded that applicants' estimates of the maximum number of people on the beach or in the water within the proposed reduced exclusion area were conservative.

The ASLAB Memorandum of Order dated January 22, 1976 (ALAB-308) resolved the issue concerning authority to control activities within portions of the new reduced exclusion area landward of the mean high tide line in the applicants' favor. However, the Board declined to deal with the question concerning the tidal beach and remanded this issue to the ASLB.

The ASLB held hearings on May 19-21, 1976, at which time evidence was heard on several issues concerning the tidal beach, including the anticipated public use of the beach.

Applicants' expert witnesses provided testimony regarding activities within the beach areas in the vicinity of the San Onofre Nuclear Generating Station and the projected number of persons that would be anticipated within the reduced exclusion area. With respect to activities within the beach areas, applicants' expert witness indicated that distances from parking and beach access points to the area in front of the station are such that there will be a low level of activity on beaches within the reduced exclusion area as compared to other beach areas in the San Onofre State Beach because beach users tend to remain relatively close to their point of beach access. With respect to the projected number of persons within the reduced exclusion area, the applicants' expert witness conservatively assumed the total number of persons which could ultimately be accommodated by all park facilities developed to their planned ultimate capacity would occupy the beach at the same time. Based upon a probabilistic distribution of that population , an estimated 35 persons would be located within the reduced exclusion area. Further, based upon actual observations of persons using the San Onofre State Beach, in addition to similar observations on other beaches, it was predicted that the average and maximum number of people using the beach in front of the station, within the exclusion area, would be 7 and 31, respectively.

NRC Staff supported the applicants' contentions and indicated in both written and oral testimony that the area directly in front of the plant was the least desirable both from an aesthetic point of view and for swimming, surfing or sunbathing, and also indicated that when one is laden with beach blankets and other recreational gear, migration up or down the beach would be discouraged, therefore, beach users would congregate relatively close to the paths up the bluffs of the San Onofre State Beach.

ASLB Order dated January 6, 1977, ordered applicant to provide all data collected since March 14, 1976, reflecting the actual daily count of persons using the beach within the applicants' exclusion area, including the tidal beach. Oral Arguments were held on February 1, 1977, during which the applicants' provided an analysis of the daily counts previously submitted to the ASLB. That analysis showed less than 10 persons were observed on the beach in the exclusion area for approximately 57.6 percent of the time, and that, on the average, only 12 to 15 percent of the total number of people observed in the study area (area in front of the station and adjacent areas 1/4 mile north and 1/4 mile south) were in the exclusion area. There was a peak number of 108 persons observed in the exclusion area, however, the 108 persons (40 percent stationary, 19 percent in transit, 20 percent swimming, and 21 percent surfing) represent about 36 percent of the total number observed in the study area. It should be noted that the administrative features proposed in Amendment 22 will only effect stationary persons within the exclusion area. Transit through the exclusion area as well as activities below the mean high tide line such as, swimming, fishing and surfing will remain unrestricted.

The ASLB Initial Decision dated May 20, 1977, ruled in the applicants' favor ordering that the Construction Permits shall be continued in effect.

Given the following facts that:

1. The conclusions drawn by the NRC staff in the DES appear to be based upon the Final Environmental Statement Construction Permit Stage.

2. The ASLAB and ASLB have given detailed consideration, in hearings, regarding usage of the beach in front of the San Onofre Nuclear Generating Station within the exclusion area.

3. The applicants provided expert testimony supporting the fact that the beach in front of the station was the least desirable from the standpoint of aesthetics for swimming, surfing or sunbathing and does not receive significant usage and that people tended to congregate near the paths of the state beach away from the exclusion area.

4. The staff supported the applicants' contention regarding minimal beach usage and undesirability of the beach in front of the station.

In view of the above, the appropriate sections of the DES should be revised to conclude that limiting the use of the beach within the exclusion area boundary and above the mean high tide line to a passage way does not represent a significant loss of recreational space.

6. ENVIRONMENTAL MONITORING

6.2 PREOPERATIONAL MONTIORING PROGRAM

Comment 6-1

(page 6-2, Fig. 6.1)

The legend is in error, the triangle symbol should represent DO, pH and Heavy Metals. The square symbol should represent continuous temperature.

6.2.1.5 Intertidal Organisms

Comment 6-2

(page 6-3, paragraph 5 and 6)

The monitoring described in the first paragraph was a requirement for Unit 1 which was deleted in September, 1977, because no effects had been detected. Although this study has been deleted as a requirement, SCE has continued an intertidal study program somewhat reduced in scope. The applicants contend continued conduct of this present cobble intertidal sampling program as described below will meet the objectives outlined in the second paragraph of Section 6.2.1.5 of the DES.

The applicants recommend replacing the existing paragrpah with the following paragraph:

"Although not a required component of the monitoring programs, quarterly observations are made along cobble intertidal transects at four monitoring stations and one control station. Predominant macroscopic species and substrate composition are identified and enumerated within three permanent 0.25m^2 (2.69-ft.^{2}) quadrats along a line perpendicular to the beach. Photographs are also taken of each quadrat for a permanent record of ecological changes."

6.2.1.6 Requirements

Comment 6-3

(page 6-3, requirement 2)

The staff requires extensive monitoring of the San Onofre kelp bed based on predictions made in Section 5.4.2.1.

Kelp investigations are currently in progress with the Construction Monitoring Program, which is a special study of the Preoperational Monitoring Program. Detailed methods are outlined in Reference (11). A brief outline of the scope of effort, at all three San Onofre region beds, is as follows:

1. Three benthic stations are located in and about the San Onofre kelp bed and one each at Barn kelp and San Mateo kelp. Stations are quantatively assessed quarterly.

2. Kelp canopies and rock substrate are mapped for areal extent on a quarterly basis.

3. Water nutrient analysis for ammonia, nitrates, nitrites and phosphate taken monthly at all three beds. Water samples are taken for the surface and bottom from within each bed and offshore of each bed. An additional offshore station serves as a monitoring area for upwelling.

4. Kelp tissue analysis for nutrient content is conducted on a monthly basis at all three kelp beds. Each leaf is analyzed for nitrogen content.

5. Assessments of the health of kelp plants in the San Onofre region beds are made on a quarterly basis. Parameters assessed include: success of juvenile recruitment, density of kelp plants, amount of encrusting organisms and grazing by herbivores and abundance of senile and diseased plants.

Based upon the applicants' extensive comments dealing with the predicted impact of the San Onofre thermal plume on the San Onofre kelp bed, the applicants contend that requirement number 2 in Section 6.2.1.6 is unwarranted and should be deleted.

6.3.1 Water quality monitoring program

Comment 6-4

(page 6-6)

The entire section is in error and should be deleted. The program that the staff discusses in the DES is actually a 1976 draft of the applicants' proposed preoperational oceanographic program. An operational program for San Onofre 2 and 3 has not yet been established.

6.3.3 Aquatic biological monitoring

Comment 6-5

(page 6-7, paragraph 2)

This paragraph states, "The applicant intends to forward a description of the study with a schedule for completion to NRC by December, 1978, (see ER, Suppl. 1, p. S1-31)."

In keeping with efforts to avoid duplication and utilize the 316(b) study results, the study plan submittal to the NRC will be made after the completion of the methods development phase of 316(b). We presently anticipate that the 316(b) method development phase will be completed in early 1979, and, therefore, the study plan should be submitted to the NRC by mid-1979.

6.3.3 Aquatic biological monitoring, and

6.3.5 Requirements for Environmental Technical Specifications

Comment 6-6

(page 6-6 and 6-7)

The DES states in Section 6.3.3, paragraph 2 and in requirement number 3, Section 6.3.5, that "...the ichthyoplankton study now being conducted and the required

kelp preoperational program should be continued during operation of the facility until such time as it is possible to state credibly that no significant impacts result from the facility."

The ichthyoplankton study being conducted is a one year program to provide a baseline for comparison with the operational ichthyoplankton study which is also envisioned to be a one year program. Further, as stated in applicants' Comment 6-4, the required kelp preoperational program is considered to be unwarranted and the requirement should be deleted.

8. NEED FOR THE STATION

8.2 APPLICANT'S SERVICE AREAS AND REGIONAL RELATIONSHIPS

8.2.1 Applicant's service areas

Comment 8-1

(page 8-1, paragraph 2)

The reference number used in the discussion appears to be incorrect.

8.3 BENEFITS OF STATION OPERATION

8.3.1 Minimization of production costs

Comment 8-2

(page 8-3, Table 8.1)

Table 8.1 was derived from the applicants' ER-OLS, Table 1.1-3 and page S.2-188. However, the data found on ER-OLS Table 1.1-3 is not the most current for 1976 and will be updated in a future amendment to the ER-OLS. The applicants have revised Table 8.1 of the DES to reflect changes in data as reported to the Federal Power Commision on Form 1, Annual Operating Report for Southern California Edison Company for the year ending December 31, 1976.
(Revised Table 8.1 (Attachment X))

8.3.2 Energy demand

Comment 8-3

(page 8-4, paragraph 2)

The discussion on the overestimation of peak demands in the 1973 forecast should also mention load management programs. The applicants suggest the last sentence be rewritten as follows:

> "These peak demands were overestimated because the 1973 forecast did not foresee the Arab oil embargo, the following period of economic recession, the nationwide effort to promote energy conservation, and load management."

Comment 8-4

(page 8-4, paragraph 3 and Table 8.3)

The staff's evaluation is based on the 1976 forecast data provided by the applicants in their ER-OLS. The data found on ER-OLS Table 1.4-1[a] is based on an early 1976 forecast and does not reflect the revised forecast (July 23, 1976) data found on ER-OLS Table 1.1-1. SCE has revised Table 8.3[b] of the DES based on ER-OLS Table 1.1-1 and their revised 1976 forecast. The last line in the second paragraph has been changed by the applicants to be consistent with the revised data and reads as follows:

> "SCE's revised 1976 forecast shows a peak demand growth rate of 3.9% from 1976 to 1985, and energy requirements are expected to experience a growth rate of 4.3% in the same period."

a. ER-OLS Table 1.4-1 will be revised in a future amendment to the ER-OLS.

b. Revised Table 8.3 (Attachment Y).

Comment 8-5

(page 8-5)

The discussion of the three forecasts that states, "their projections do not reflect non-price-induced conservation...," this does not consider current SCE forecast methodology. Non-price-induced standards were incorporated into SCE's peak demand forecasts, e.g., the peak demand for 1985 includes a 2.4% reduction due to load management and the "weather sensitive demand" for 1985 was reduced 29% because of building insulation and air conditioning efficiency standards (Reference 19 and 20). Therefore, the discussion on page 8-5, specifically paragraphs 1, 3 and 4 should be modified.
(see Attachments Q and R)

10. BENEFIT-COST SUMMARY

10.2 BENEFITS

Comment 10-1

(page 10-1, paragraph 2, and page 10-2, Table 10.1)

The net power output for each unit is estimated to be in the range of 1052 to 1106 MWe (see Comment A-1 for discussion). The regional generating capacity will be increased 2104 to 2212 MWe with the addition of Units 2 and 3. The discussion on the primary benefit and Table 10.1 should be revised to reflect the estimated net power output.

10.7 SUMMARY OF BENEFIT-COST

Comment 10-2

(page 10-3, item (2))

The "possible destruction of at least a portion of the San Onofre Kelp Bed during summer months by the heated water discharge" is listed as an additional environmental cost. Because this cost is based on an assessment performed by the staff using disputed data, the applicants request that this cost be deleted if the reassessment of Section 5.4.2.1 Effects of the heat dissipation system warrants such a change.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
215 Fremont Street
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Project # D-NRC-K06002-CA

William H. Regan, Jr., Chief
Environmental Projects, Branch 2
Division of Site Safety & Environmental
Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan: FEB 13 1979

The Environmental Protection Agency has received and reviewed the draft environmental statement for the SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 and 3, SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS AND ELECTRIC COMPANY.

EPA's comments on the draft environmental statement have been classified as Category ER-2. Definitions of the categories are provided on the enclosure. The classification and the date of EPA's comments will be published in the Federal Register in accordance with our responsibility to inform the public of our views on proposed Federal actions under Section 309 of the Clean Air Act. Our procedure is to categorize our comments on both the environmental consequence of the proposed action and the adequacy of the environmental statement.

EPA appreciates the opportunity to comment on this draft environmental statement and requests three copies of the final environmental statement when available.

If you have any questions regarding our comments, please contact Betty Jankus, EIS Coordinator, at (415)556-6695.

Sincerely,

Sheila M. Prindiville

for Paul De Falco, Jr.
Regional Administrator

Enclosure

A-38

Water Quality Comments

1. In Section 5.3.1.1., some assessment is made of the effects of the discharge of heated cooling water on the receiving coastal waters with regards to the California State thermal standards. When evaluating thermal discharge, all effects of Units 2 and 3 should be considered in conjunction with the effects of Unit 1. The natural background is a situation where none of the three units is operating. The natural receiving water temperature as defined by California Thermal Plan (see next paragraph) is "the temperature of the receiving water at locations, depths, and times which represent conditions unaffected by any elevated temperature waste discharge". Unless Units 2 and 3 are not planned to operate concurrently with Unit 1, their effects will occur in concert. All modeling, graphs, and maps produced from models should include Unit 1 effects when evaluating SONGS' effects on the receiving water temperature.

   Under Section 316(a) of the Federal Water Pollution Control Act of 1972 (FWPCA) and under the Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California (1975 Thermal Plan) (EPA approved State water quality standards), there are several criteria which discharges to coastal waters must fulfill. These should be addressed in any EIS on operating a new coastal discharge of elevated temperature wastes. These are as follows:

   a. In part 3.B.(3.) of the Thermal Plan, it is stated that "the maximum temperature of thermal waste discharges shall not exceed the natural temperature of receiving waters by more than 20°F." Part 3.2.2. of the DEIS states that the cooling water "experiences an 11.1°C (20°F) temperature rise across the condenser." Since the waters in the vicinity of the intakes for Units 2 and 3 are close to the discharge structures for these units, it is possible that these intake waters are already heated beyond their natural temperature. Some evaluation of this effect must be included in the FEIS. The influence of the heated discharge from Unit 1 must also be described. In addition, the intake

and discharge facilities and their depths and how temperature stratification profiles relate to the 20°F requirement should be discussed.

b. In Part 3.B.(4) of the Thermal Plan, it is stated that "the discharge of elevated temperature wastes shall not result in increases in the natural water temperature exceeding 4°F at (a) the shoreline, (b) the surface of any ocean substrate, or (c) the ocean surface beyond 1,000 feet from the discharge system. The surface temperature limitation shall be maintained at least 50 percent of the duration of any complete tidal cycle." Figure 5.3 of the DEIS represents projected incremental increases above natural surface temperatures for the study area. This figure should be changed in the FEIS to include the Unit 1 intake and discharge structures and the increase of surface temperatures already caused by Unit 1 discharges in conjunction with those of Units 2 and 3 so as to compare the increases with the true natural surface water temperature.

c. In addition, the FEIS should document the estimate (Section 5.3.1.2) of the increase in temperatures at the surface of the ocean substrate around the discharges. This estimate indicates that "violations of the state thermal standards are unlikely." Again, such estimates should compare natural temperatures to the combined effects of Units 1, 2, and 3. These temperatures are of special concern because of the importance of low basal temperatures to maintaining the nearby kelp bed.

d. Finally, the Thermal Plan and Section 316(a) of the FWPCA assert the need to "assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made". In Section 5.4.2.1 of the DEIS, biological/ecological evaluations refer to the effects of the discharges on various types of organisms, indicating the effects to be minimal and acceptable. For plankton, the effects will be "species composition changes" and

"greater respiration rates", also, "significant effects should be localized". For fish, the effects will be mainly "shifts in the types of species (and their numbers) which inhabit the area". For benthic fauna, adverse effects may be expected if "weekly mean temperatures of 22°C prevail for one month or more or where daily temperatures reach or exceed 24°C. It is not, however, anticipated that temperatures averaging 22°C will occur for more than 2 to 3 weeks or that the area experiencing temperatures of 24°C or greater as a result of SONGS operation will be considerably larger than the area experiencing these temperatures under natural conditions". For kelp, the information "suggests that the thermal discharges from SONGS 1, 2 and 3 may result in the destruction of at least a portion of the San Onofre Kelp Bed during the summer months". All of these statements indicate that the indigenous populations will be altered, giving no specific documentation that these effects will be minimal or acceptable. A detailed evaluation of how the aquatic ecosystem will be affected, over what area each species or type of fauna may be influenced, and what constitutes a significant adverse effect should be made and presented clearly in the FEIS.

2. Section 5.4.2.1. Thermal Effects, mentions a final report due on December 29, 1978. This study, provided for under the Thermal Plan and Section 316(a) of the FWPCA, is to be used in evaluating the heat-treatment process which is used to clear the intake facilities of biological growth. EPA considers this study to be an integral part of the assessment of the environmental effects of the thermal discharges from the Units. As such, it must be distributed, along with biological and water quality assessments and conclusions (perhaps in the form of a supplement to the DEIS) to all recipients of this DEIS, with the allowance of a comment period prior to incorporation in the Final EIS.

3. Section 5.4.2.2 includes a discussion of the potential effects of chlorine discharges. The discussion evaluated potential "significant impacts" of the periodic 15-minute chlorine dosing period. The FEIS should include a comparison of effluent concentrations with the State Standards contained in the Water Quality Control Plan for the Ocean Waters of California (1978 Ocean Plan), Table B and Footnote 11, should appear in the EIS. Should the comparison predict that the discharges exceed the requirements, the plans to lower the discharge concentration to agree with the State Standards must be described in the FEIS.

4. No assessment appears in the DEIS of the potential seismic effects of nearby faults on the units, although there is a fault within a mile of the plant (the Christianitos Fault and others in the vicinity). The FEIS should address the potential of seismic events and the resultant damage from fault movement, with particular emphasis on the water quality and off-site radiological contamination.

Radiological Comments

Beach Regulation

This DEIS gives little information on the anticipated beach population. The presence of thousands of daytime beach users and hundreds of overnight campers within 1.5 miles from the reactors has significant security, emergency planning, and radiation dose implications. Consequently, we believe this issue warrants a thorough discussion in the Final EIS so that those reviewers who will not read the Environmental Review and Emergency Plan will be aware of this situation and have an opportunity to evaluate it.

We agree with the decision to restrict usage of the beach in front of the reactors since it will simplify the security and emergency planning problems and will reduce the radiation doses to the population from routine release. However, the practical effectiveness of this restriction should be addressed in the FEIS (e.g., is the prohibition against restricting the area seaward of mean high water, coupled with permitting viewing and pedestrian passage going to make enforcement difficult?).

It would be helpful to briefly mention the Emergency Response Plan that is in effect for the Nuclear Station and relate it to the transient population.

As mentioned under the Dose Commitment section, it is not clear whether beach users and Visitor Center users are included in the individual and population dose calculations.

Environmental Dose Commitments

Page 5-31-34 of the DEIS:

The estimated maximum individual dose and the population dose were independently checked by EPA with results similar to those presented in the DEIS. However, we do have several questions about assumptions used in the DEIS calculations. The FEIS should clarify the following items:

1. The manner in which the individual and population dose to users of the beach is calculated is unclear. For example, what allowance is made for direct radiation doses, especially to those using the walkway between the south and north beaches, and to those at the Visitors Center? Do the individual and population doses include these users of the beach and the Visitors Center and, if so, what assumptions were made on hours of exposure, shielding factors, etc.? Also, it would be helpful if the habits of "a maximum individual" were described so it could be determined to what extent these various pathway dosages are additive.

2. The actual maximum individual dose from present operation of Unit 1 should be described. This dose should be added to those being projected for Units 2 and 3 (from all pathways). This, in turn, should be compared with the 25 millirem per year limit (75 millirem per year to the thyroid) of the Uranium Fuel Cycle Standard (40 CFR 190).

EPA is encouraged that the NRC is now calculating annual population dose commitments to the U.S. population, which is a partial evaluation of the total potential environmental dose commitments (EDC) of H-3, Kr-85, C-14; iodines and "particulates." This is a big step toward evaluating the EDC which EPA has urged for several years. However, it should be recognized that several of these radionuclides (particularly C-14 and Kr-85) will contribute to long-term population dose impacts on a world-wide basis, rather than just in the U.S. To the extent that the draft statement (1) has limited the EDC to the annual discharge of these radionuclides, (2) is based on the assumption of a population of constant size, and (3) assesses the doses during 50 years only following each release, it does not fully provide the total environmental impact. Assessment of the total impact would (1) incorporate the projected releases over the lifetime of the facility (rather than just the annual release), (2) extend to several half-lives or 100 years beyond the period of release, and (3) consider, at least qualitatively or generically, the world-wide influences on the total environmental impact or specify the limitations of the model used.

Environmental Monitoring

The pre-operational and operational radiological environmental monitoring program (as described in Section 6.1.5 of the Environmental Report) appears adequate with the following exceptions which the FEIS should address:

1. A delay of 8 days before analyzing charcoal filter air samples would permit over 99% of the Iodine-133 and 50% of the Iodine-131 to decay before being counted. The decay would be much greater for contamination occurring at the beginning of the 7-day sampling period. The maximum time before analyzing filters should be shortened significantly in order to detect as many incidences of sporadic contamination as possible.

2. It is not clear why a minimum of only ten 7-day air particulate samples are required per quarter. The intent should be to monitor all 13 weeks in a quarter.

3. No TLD stations are indicated for the walkway along the seawall or the mean high water exclusion area in front of the reactors. It would be desirable to include TLD's at these locations to monitor the direct radiation at a site boundary where the public has access.

Reactor Accidents

The EPA has examined the NRC's analyses of accidents and their potential risks. The analyses were developed by NRC in the course of its engineering evaluation of reactor safety in the design of nuclear plants. Since these issues are common to all nuclear plants of a given type, EPA accepts NRC's generic approach to accident evaluation in the DEIS. However, the NRC is expected to continue to ensure safety through plant design and accident analyses during the licensing process on a case-by-case basis.

In 1972, the AEC initiated an effort to examine reactor safety and the resultant environmental consequences and risks on a more quantitative basis. The final report of this effort was issued in October 1975 by the U.S. Nuclear Regulatory Commission as the Reactor Safety Study, WASH-1400 (NUREG-75/014). The EPA's review of this study

included in-house and contractual efforts, and our comments were released in a report in June, 1976. In subsequent discussion with NRC we determined that of the concerns we expressed, those having the most significance with regard to the results of the study were on (1) the latent cancer health effects and (2) the probability of BWR scram failure where we differed by factors of four and a maximum of ten, respectively. We believe that the methodology of the Reactor Safety Study should continue to be used as a tool in the evaluation of nuclear systems that vary from the models chosen for the study, and that a generic analysis should be made of the acceptability of the present risks and the necessity for increased levels of safety.

High-Level Waste Management

The techniques and procedures used to manage high-level radioactive wastes will have an impact on the environment. To a certain extent, these impacts can be directly related to the individual projects because the spent fuel from each new facility will contribute to the total waste. The AEC, on September 10, 1974, issued for comment a draft statement entitled "The Management of Commercial High-Level and Transuranium-Contaminated Radioactive Waste" (WASH-1539). In this regard, EPA provided extensive comments on WASH-1539 on November 21, 1974. Our major criticism was that the draft statement lacked a program for arriving at a satisfactory method of "ultimate" high-level waste disposal. At present, DOE is preparing a new draft statment which will discuss waste management and emphasize ultimate disposal in a more comprehensive manner. EPA concurs with this decision and will review and comment on the new draft statement replacing the September 10, 1974 version when it is available.

EPA is cooperating with both NRC and DOE to develop an environmentally acceptable program for radioactive waste management. In this regard, on November 15, 1978, EPA issued proposed environmental radiation protection criteria (43 FR 53262) for the management of all radioactive waste and will propose environmental radiation protection standards for high-level waste in 1979.

Transportation

In its earlier reviews of the environmental impacts of transportation of radioactive material, EPA agreed with AEC that many aspects of this program could best be treated on a generic basis. The NRC has codified this generic approach (40 FR 1005) by adding a table to its regulations (10 CFR Part 51) which summarizes the environmental impacts resulting from the routine transportation of radioactive materials to and from light-water reactors. These regulations permit the use of the impact values listed in the table in lieu of assessing the transportation impact for individual reactor licensing actions if certain conditions are met. Since San Onofre appears to meet these conditions and since EPA agrees that the routine transportation impact values in the table are reasonable, the generic approach appears adequate for this plant.

The impact value for routine transportation of radioactive materials has been set at a level which covers 90 percent of the reactors currently operating or under construction. However, the basis for the impact, or risk, of transportation accidents is not as clearly defined. At present, EPA, DOE, and NRC are each attempting to more fully assess the radiological impact of transportation risks. The EPA will make known its views on any environmentally unacceptable conditions related to transportation. On the basis of present information, EPA believes there are no unique characteristics of the San Onofre site which would result in greater accident risks than from the "typical" site being studied generically.

Fuel Cycle and Long-Term Dose Assessments

EPA is responsible for establishing generally applicable environmental radiation protection standards to limit unnecessary radiation exposures and radioactive materials in the general environment resulting from normal operations that are part of the total uranium fuel cycle as well as those of the facilities. The EPA has concluded (in 40 CFR 90) that environmental radiation standards for nuclear power industry operations should take into account the total radiation dose to the population, the maximum individual dose, the risk of health effects attributable to these doses (including the future risks arising from the release of long-lived radionuclides to the environment), and the effectiveness and costs of effluent

control technology. EPA's Uranium Fuel Cycle Standards are expressed in terms of dose limits to individual members of the general public and limits on quantities of certain long-lived radioactive materials released to the general environment.

A document entitled "Environmental Survey of the Uranium Fuel Cycle" (WASH-1248) was issued by the AEC in conjunction with a regulation (10 CFR 50, Appendix D) for application in completing the cost-benefit analysis for individual light-water reactor environmental reviews (39 FR 14188). This document is used by NRC in draft environmental statements to assess the incremental environmental impacts that can be attributed to fuel cycle components which support nuclear power plants.

Recently, the NRC decided to update the WASH-1248 survey. We believe this is a prudent step and commend the NRC on initiating this update. In providing comments to the NRC on this subject, dated November 14, 1978, we encouraged NRC to express environmental impacts in terms of potential consequences to human health, since for radioactive materials and ionizing radiation the most important impacts are those ultimately affecting human health. We believe the presentation of environmental impact in terms of human health impact fosters a better understanding of the radiation protection afforded the public.

A second major concern of EPA deals with the discharge and dispersal of long-lived radionuclides into the general environment. In the areas addressed in WASH-1248, there are several cases in which radioactive materials of long persistence are released into the environment. The resulting consequences may extend over many generations and constitute irreversible public health commitments. This long-term potential impact should be considered in any assessment on health impact. EPA has consistently found inadequate the NRC's estimates of population doses for these persistent radioactive materials. In particular, the NRC has generally limited their analysis to the population within 50 miles of a facility or, in rare cases, to the U.S. population, and to doses committed for a 50-year period by an annual release. These limitations produce incomplete estimates of environmental impacts and underestimate the impact in some cases, such as from releases of tritium, Krypton-85, Carbon-14, Technetium-99, and Iodine-129. The total impact of these

persistent radionuclides should be assessed, qualifying such estimates as appropriate to reflect the large uncertainties. In this regard, we note that NEA is addressing this approach in making assessments and that NRC is represented in this effort.

Another major consideration in updating WASH-1248 is the health impact from Radon-222 from the uranium mining and milling industry. Estimates made by EPA, among others, indicate that Radon-222 contributes the greatest fraction of the total health impact from nuclear power generation. In preparing an updated WASH-1248, we believe NRC should:

1. include the Radon-222 contribution from both the uranium mining and milling industries;

2. determine the health impact to larger populations, not only the local populations;

3. recognize the persistent nature of the Radon-222 precursors (Th-230 and Ra-226) by estimating the health impact for a period reflecting multi-generation times.

Decommissioning

The NRC has published a proposed rulemaking on Decommissioning Criteria for Nuclear Facilities in the Federal Register on March 13, 1978. EPA comments were sent to NRC on July 5, 1978, dealing with the decommissioning issue.

In summary, we believe that one of the most important issues in the decommissioning of nuclear facilities is the development of standards for radiation exposure limits for materials, facilities, and sites to be released for unrestricted use. We have included the development of such standards among our planned projects. The work will require a thorough study to provide necessary information, including a cost-effectiveness analysis for various levels of decontamination.

The development of standards for decommissioning must, of course, include consideration of the many concurrent activities in radioactive waste management and radiological protection. EPA has developed proposed Criteria for Radioactive Waste for management of all

radioactive wastes which will provide guidance for decommissioning standards. From the decommissioning view, probably the most important criterion is that limiting reliance on institutional controls (guards and fences) to a finite period. EPA believes that the use of institutional control to protect the public from retired nuclear facilities until they can be decontaminated and decommissioned should be limited at the most to 100 years and preferably less than 50 years. This includes nuclear reactors shut down and mothballed or entombed for a period of time under protective storage. After the allowable institutional care period is over, the site will have to meet radioactive protection levels established for release for unrestricted use. We believe EPA's proposed criteria would be directly applicable, as above, to decommissioning of nuclear facilities and should be given serious consideration by the Nuclear Regulatory Commission (NRC).

The availability of adequate funds when the time to decommission arrives is also most important; it should be the responsibility of the NRC to assure that such provisions are made. We recognize the great complexity of providing funds at construction for decommission in 40 years. However, if it can be determined that the total cost of decommissioning in current dollars is a very small fraction of initial capital costs, provision of escrow funding may not be necessary. Therefore, we urge the NRC to conduct the necessary studies and assessments to determine unequivocally costs of decommissioning and to compare such costs to initial capital costs. It is only through a definitive analysis, and perhaps through realistic demonstrations, that this issue can be resolved.

EIS CATEGORY CODES

Environmental Impact of the Action

LO--Lack of Objections

EPA has no objection to the proposed action as described in the draft impact statement; or suggests only minor changes in the proposed action.

ER--Environmental Reservations

EPA has reservations concerning the environmental effects of certain aspects of the proposed action. EPA believes that further study of suggested alternatives or modifications is required and has asked the originating Federal agency to reassess these aspects.

EU--Environmentally Unsatisfactory

EPA believes that the proposed action is unsatisfactory because of its potentially harmful effect on the environment. Furthermore, the Agency believes that the potential safeguards which might be utilized may not adequately protect the environment from hazards arising from this action. The Agency recommends that alternatives to the action be analyzed further (including the possibility of no action at all).

Adequacy of the Impact Statement

Category 1--Adequate

The draft impact statement adequately sets forth the environmental impact of the proposed project or action as well as alternatives reasonably available to the project or action.

Category 2--Insufficient Information

EPA believes that the draft impact statement does not contain sufficient information to assess fully the environmental impact of the proposed project or action. However, from the information submitted, the Agency is able to make a preliminary determination of the impact on the environment. EPA has requested that the originator provide the information that was not included in the draft statement.

Category 3--Inadequate

EPA believes that the draft impact statement does not adequately assess the environmental impact of the proposed project or action, or that the statement inadequately analyzes reasonably available alternatives. The Agency has requested more information and analysis concerning the potential environmental hazards and has asked that substantial revision be made to the impact statement.

If a draft impact statement is assigned a Category 3, no rating will be made of the project or action, since a basis does not generally exist on which to make such a determination.

Marvin I. Lewis
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Phila. PA 19149
3-6-79.

Director, Division of Site Safety Environmental Analysis
Office of nuclear Reactor Regulation
USNRC
Washington. /d.C. 20555
Sir:
NUREG 0490 does a lot of things , but it does not in any way justify the operation of the San Onofre Nuclear Generating Station.

Although the NUREG does provide a lot of good information, this information actually contradicts the usefulness of the SONGS, Sa n Onofre Nuclear Generating Station. For instance, the growth rate in Table 2.2 ,Page 2-2, is 3.5 % or less for the period 1976 to 1990. The growth rate in Table 8.3 and 8.4 on Pages ~~11~~ 8-4and 8-5 is close to 5% for the same period. Inotherwords , the growth rates in various parts of the report are 'selected ' to provide justification for whatever the writer wishes to fustify in any ~~XXXXX~~ particular part of the report. This technique is called 'fiction'.

In Appendix D-23 Page 2.5 Seismology is dismissed in a few paragraphs. Considering the recent and continuing ~~xxx~~ seismic discoveries at the Hosgri fault at Diablo Canyon (which is in a similar -in fact same- gelological domain), passing off seismology this cavalierly ~~in~~ is indefensible.

Page 5-37. First you state in a Table that the Commissioner has directed that Radon 222 will be reconsidered elsewhere; then, the Staff includes Radon 222 in this Nureg in a convoluted and artificial manner which does not in any way investigate or acknowledge Radon 222's full period of toxicity as required by NEPA.

Page 5-39 Tailings are not required to be stabilized forever, and even if it ~~xxxxx~~ were required , forever stabilization is a God like requirement~~?~~ which may be impossible to mortal men~~?~~.

~~C~~hapter 7. This is based entirely on the Rasmussen Wash 1400 . Commisssioner Kennedy has already stated on October 1~~6~~, 1978, "It (Rasmussen Report) found some deficiendies which suggest that the absolute values of the risks presented in the Study should not be used uncritically either i~~n~~ the regulatory process or for public policy purposes."

The DES for operation of SONGS proves unequivocally that this nuclear power plant is unnecessary and dangerous. This is despite the Stall evaluation which ignores all important negative effects.

DO NOT LICENSE THIS NUCLEAR POWER PLANT TO OPERATE AT THE EXPENSE OF HUMAN LIVES.

Marvin I. Lewis

A-45

Southern California Edison Company
P. O. BOX 800
2244 WALNUT GROVE AVENUE
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SCE
J. H. DRAKE
VICE PRESIDENT
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April 6, 1979

Director, Office of Nuclear Reactor Regulation
Attn: Wm. H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and
Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Gentlemen:

Subject: San Onofre Nuclear Generating Station
Units 2 and 3
Docket Nos. 50-361 and 50-362

Mr. Oliver Lynch, Jr., of the NRC staff called on March 27, 1979, to request clarification of Applicants' Comment 6-4 to the Draft Environmental Statement for San Onofre Nuclear Generating Station, Units 2 and 3. Applicants' Comment 6-4 was submitted with other comments by letter to you dated February 2, 1979.

In response to Mr. Lynch's request, a revised Comment 6-4 is enclosed for your information. If you have additional comments regarding this comment, please contact me.

Sincerely,

Enclosure

7904240399

Copy ES 1/1

6.3.1 Water Quality Monitoring Program
Comment 6-4 (Revised April 6, 1979)
(Page 6-6)

The first five paragraphs of this section of the DES describe a proposed operational monitoring program which was presented in the ER-OLS (Section 6.2) and was based upon the proposed preoperational monitoring program also presented in the ER-OLS. The ER-OLS was developed in 1976 and submitted in 1977 to the NRC.

Since that time, the Preoperational Monitoring Program has been revised to incorporate the latest site specific study results and recent developments in marine ecological study techniques. The revised Preoperational Monitoring Program was approved by the NRC and implemented in 1978. It is the Applicant's intention to develop an operational monitoring program which incorporates results of the Preoperational Monitoring Program and submit it in the near future for approval. It was the intention of Comment 6-4 to indicate that the specific details of the operational monitoring program proposed in the ER-OLS in 1976 (and contained in the DES) should not be considered to represent the program which will actually be implemented. While the program which will ultimately be implemented will be similar to the one included in the ER-OLS, it will not be identical, and the differences between the two cannot be specified at this time because the development process is still underway.

A-46

RICHARD J. WHARTON
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Attorney for Intervenors

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of SOUTHERN CALIFORNIA EDISON COMPANY, et al., (San Onofre Nuclear Generating Station, Units 2 and 3)	Docket Nos. 50-361 OL 50-362 OL COMMENTS ON DRAFT ENVIRONMENTAL STATEMENT - SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3

We have carefully reviewed the above draft environmental statement in relation to the requirements imposed by Section 102(2)(c) of the National Environmental Policy Act (NEPA) and 10 CFR Part 51 of the NRC Regulations, and have set forth below intervenors' comments on the proposed action and on this draft statement pursuant to 10 CFR Part 51.25. Intervenors find this draft statement inadequate in a) the discussion and assessment of environmental effects, both beneficial and adverse, associated with the operation of the San Onofre Nuclear Generating Station, Units 2 and 3, and b) the discussion and consideration of available alternatives to the proposed action. Intervenors specifically identify the following deficiencies:

1. The evaluation of cooling water discharge impacts is

inaccurate and misleading. The heated water will very likely result in the destruction of at least a portion of the San Onofre kelp bed during the summer months, the long-term thermal impacts are likely to be severe, and violations of the state standards will occur. On page 5-7 of the DES it is stated: "The staff concludes that although there exists a remote possibility that state thermal standards could be violated by the operation of Units 2 and 3, violations would, at worst, be infrequent and for short periods. There is no evidence in available drift data to indicate that such an occurence would take place during the summer when thermal impacts would be most severe." This conclusion was apparently based on applicants' "worst case" modeling theory; however, in light of recent findings as a result of studies presently being performed by the Marine Review Committee (MRC) at the request of the California Coastal Commission, it has been determined that the state thermal standards will not be met. The following excerpts from the "Supplemental Staff Report And Recommendations - Review of Thermal Requirements For San Onofre Nuclear Generating Station, Units 2 and 3" prepared by the California State Water Quality Control Board staff are appropriate: "The Report of the MRC confirms the previous prediction that, under normal operating conditions, the proposed discharge will violate the 20 degree F temperature differential in the "receiving waters" i.e., waters at the location and depth of the diffusers of Units 2 and 3. This Report notes: '...if the "receiving" waters are defined as in this paragraph, the standards of the State Thermal Plan will probably be exceeded by the operation of Units 2 and 3.' Although the Report indicates that the discharge will "likely" or "probably"

or "may" violate the temperature differential, there really is no question that such violations will occur." (pp. 4-5)

In a hearing for the purpose of interpreting the term "receiving waters" held on December 21, 1978, the California State Water Quality Control Board held that "...the temperature at the intake point does not represent conditions at the receiving waters," (p. 3 of Opinion of Chairman Bryson and Board Member Mitchell) contrary to applicants' requested interpretation. The net result of this ruling is that the state thermal discharge limitation will be exceeded by operation of SONGS Units 2 and 3.

The DES states at p. 5-27 "The greatest threat of SONGS to the long-term survival of the San Onofre kelp bed is the possibility of injury to the basal tissues from which the canopy is regenerated each year...under extreme worst case conditions (e.g., several days with high ambient temperatures and slack currents, and with all the plants operating continuously), destruction of the basal regenerative tissues might result." The DES further states: "...the community (kelp bed), if destroyed frequently, could never achieve a stable state characteristic of other kelp beds in the area. Furthermore, constant temperature increases coupled with added turbidity would be inimical to interim reestablishment...The perennial occurrence of worst case conditions seems highly unlikely and the staff thus concludes that the long-term thermal impacts from normal station operation are not likely to be severe." (p . 5-27) It is clear that since the state thermal discharge limitation will be exceeded during normal operation of SONGS 2 and 3, the staff's conclusion was based on a faulty premise. Dischargers' normal plant operation will result

in continuous high temperature discharge approximating the worst case conditions and resulting in both short and long-term thermal impacts on the San Onofre kelp beds. The DES states at p. 5-27 "It has been rather well established that temperatures above 18-20 degrees C. (64-68 degrees F) cause deterioration of kelp, and the degree of degradation is directly related to the duration of the exposure to these temperatures."

2. The DES is inadequate in its discussion of the 316(a) exception process as related to thermal pollution caused by the proposed action. Section 6.4.1 of the DES discusses the "thermal exception studies" as related only to periodic "heat treatment" to control fouling organisms. The DES fails to consider the 316(a) exception required for continuous high ambient temperature discharges during the normal operations of Units 2 and 3. It is highly likely that a 316(a) exception request will be forthcoming from applicants in light of the recent denial by the California State Water Quality Control Board of applicants' requested interpretation of the term "receiving waters" as used in the State Thermal Plan. Had applicants' interpretation been approved, it would have obviated applicants' need for a 316(a) exception to the requirements of the FWPCA. Because a 316(a) exception is necessary for the operation of Units 2 and 3 in their present design mode, the DES is inadequate for failure to consider the implications, both short and long-term, on the aquatic environment if such an exception is granted. With respect to the maximum temperature of thermal waste discharges, and contrary to the requirements of 10 CFR Part 51.23(c), due consideration was not given to "...compliance of the facility construction or operation

and alternative construction and operation with environmental quality standards and requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection, including applicable zoning and landuse regulations and water pollution limitations or requirements promulgated or imposed pursuant to the Federal Water Pollution Control Act."

3. The DES is inadequate in its evaluation and analysis of the social and economic impact of operating SONGS 2 and 3.

A. With respect to the environmental impact of SONGS on recreational resources, the DES recognizes the failure of applicants to comply with the terms and conditions of the construction permit: "The current plan to restrict the use of approximately 25% of the 3 1/2 mile San Onofre Beach for the 30-year operating life of the plant is a significant loss of valuable recreational and scenic space and represents a substantial change in action between issuance of the FES-CP and application for an operating license." (Section 5.6.5) Staff reiterates previous statements made in the FES-CP that "the beach...is considered to be a unique and scarce recreational resource," (FES-CP, p. 2-11) and "that closure even for a brief period is objectionable" (FES-CP, p. 8-11). Despite the re-affirmation of these judgments, staff concludes that the social and economic impact of operating SONGS 2 and 3 - with the significant exception of restricting public use of the beach - will be only "moderate". The overall impact will be more severe than "moderate" if the beach access restriction is factored into the balancing process. Staff's treatment of this issue is misleading and inconsistent

with the purpose and intent of NEPA, section 102(2)(c), which calls for preparation of a detailed statement on, among other things, any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented. Restriction of the public's use of this beach is such an irreversible and irretrievable commitment of resources.

B. With respect to the economic impact of SONGS 2 and 3, the DES provides no analysis of the effects of the Jarvis-Gann Amendment (Proposition 13). The DES states that "The applicant should reassess the potential tax benefits accruing to these jurisdictions and districts in light of Proposition 13." (p . 5-44) This is a wholly inadequate treatment of the economic impact of SONGS 2 and 3, inasmuch as the revenue from the plant and its allocation within communities will be "significantly different from what was assumed" - to use the staff's own words - in this economic impact analysis. (p . 5-44, section 5.6.4)

4. The DES inadequately evaluates the environmental impact of postulated accidents in that Class 9 occurrences were omitted from consideration. (Section 7-1) The DES states on p. 7-2 with respect to Class 9 occurrences that "Their consequences could be severe." The DES fails to discuss the probability of Class 9 occurrences in a complete and comprehensive manner. In view of the recent earthquake fault discoveries near the San Onofre site and the existence of the dewatering-well cavities found beneath the site, a full discussion of failures more severe than those required for consideration in the design bases of protective systems and engineered safety features (Class 9) is warranted. Further, the estimated dose of 1400.00 man-rems to population in

the 50-mile radius for a large-break loss of coolant accident (Table 7.2, p. 7-3, Class 8.1) is substantial and inadequately discussed, if at all, in the text.

5. The DES is inadequate in that it fails to discuss the environmental impacts to the region in the event of an accidental release of radiation requiring evacuation. No discussion is contained in the DES as to the adaptability of the San Onofre site to adequate evacuation processes including evacuation of the nearby beach areas during times of peak use; no discussion is contained in the DES as to the suitability of existing evacuation plans; no discussion is contained in the DES as to the effects which adoption of the NRC/EPA Task Force Report on Emergency Planning (NUREG-0396) will have on evacuation within the new and expanded Emergency Planning Zone as distinct from the presently designated Low Population Zone (NRC Regulations 10 CFR Part 100).

6. The DES is inadequate in that it fails to reassess the seismic design basis for SONGS 2 and 3 in light of a) the dewatering-well cavities and b) the recent earthquakes and faults discovered since the current design basis was established.

7. The DES is inadequate in that the cost/benefit analysis fails to provide consideration for the greatest possible escalation of uranium prices, based on recent occurrences, for SONGS 2 and 3 over the operating life of the plant. The projected fuel costs identified as $87,900,000/yr for 1981 (Table 10.1, p. 10-2), will possibly escalate to a prohibitively high level since long-term uranium contracts are generally tied to market price at delivery or 7$ per year escalation, whichever is greater Staff admits (section 10.3) that since the issuance of the FES-CP

the fuel, operating, and maintenance costs of nuclear plant operation have escalated more rapidly than anticipated. The DES does not discuss adequately the possibility of additional future escalation of costs with respect to the fuel requirements of San Onofre, and does not utilize a "worst possible case" approach to determine total fuel costs over the operating life of the plant. The cost/benefit analysis contained in the DES is therefore invalid.

8. The DES is inadequate in that it fails to discuss the possibility that decommissioning costs may escalate to prohibitively high levels by the end of the operating life of the plant, at which time the applicant is required to prepare a proposed decommissioning plan for review by the NRC. (Section 9.4) Although NRC regulations do not require the applicant to have developed a decommissioning plan at the time an operating license is obtained, the discussion of alternative decommissioning methods and their associated costs found in the DES is misleading and does not present an accurate projection of what the actual decommissioning costs for SONGS will be. Staff calculations for determining decommissioning costs per unit of electricity generated do not utilize a start-up date of 1981 or an escalation rate based on the current rate of inflation. Staff's projection that "For the SONGS Units 2 and 3 the decommissioning costs would be about double that indicated for all of the decommissioning one-unit alternatives" (p. 9-17) is wholly inadequate for purposes of making an informed cost/benefit judgment. As a consequence, the cost/benefit analysis for SONGS 2 and 3 is invalid.

9. The DES is inadequate in that it fails to comprehensively

discuss the temporary storage of nuclear waste materials, including the interim storage of spent fuel, on site.

10. The DES is inadequate in that it fails to discuss the issue of plant security and provide assurances that all nuclear materials will remain accounted for and protected from the risk of terrorist or criminal activity or sabotage.

Because due consideration was not given to compliance with the requirements of 10 CFR Part 51.23(c), and because this DES fails to consider all environmental impacts of the proposed action and alternatives to the proposed action as required by Section 102(2)(c) of NEPA, staff's conclusion that the action called for is the issuance of operating licenses for Units 2 and 3 of SONGS is premature and founded on insufficient and inaccurate data.

For the foregoing reasons, intervenors request that the NRC either a) adequately address the issues raised above in the final environmental statement for SONGS 2 and 3, or b) deny applicants' request for licenses to operate SONGS 2 and 3.

Dated: Jan. 30, 1979

Respectfully submitted,

Richard J. Wharton

RICHARD J. WHARTON
Attorney for Intervenors

COMMENTS ON SUPPLEMENT TO DRAFT ENVIRONMENTAL STATEMENT

A-51

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FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

IN REPLY REFER TO:

January 23, 1981

Mr. Frank J. Miraglia
Acting Chief, Licesning Branch
No. 3
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Miraglia:

A-52

I am replying to your request of January 16, 1981 to the Federal Energy Regulatory Commission for comments on the Supplement to the Draft Environmental Impact Statement related to the operation of the San Onofre Nuclear Generating Station, Units 2 and 3. This Draft EIS has been reviewed by appropriate FERC staff components upon whose evaluation this response is based.

This staff concentrates its review of other agencies' environmental impact statements basically on those areas of the electric power, natural gas, and oil pipeline industries for which the Commission has jurisdiction by law, or where staff has special expertise in evaluating environmental impacts involved with the proposed action. It does not appear that there would be any significant impacts in these areas of concern nor serious conflicts with this agency's responsibilities should this action be undertaken.

Thank you for the opportunity to review this statement.

Sincerely,

Jack M. Heinemann
Advisor on Environmental Quality

8101[illegible]408

United States Department of Agriculture
Economics and Statistics Service
Washington, D.C 20250

January 26, 1981

Mr. Frank J. Miraglia
Acting Chief, Licensing Branch No. 3
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Miraglia:

Thank you for forwarding the Supplement to the Draft Environmental Statement for the San Onofre Nuclear Generating Station, Units 2 and 3.

We have reviewed the material, Docket Numbers 50-361 and 50-362, and have no comments at this time.

Sincerely,

MELVIN L. COTNER
Director, Natural Resource
Economics Division

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Oceanside, California
January 6, 1981

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

I wish to comment on the environmental impact report your organization supplied on the installation and licensing of the nuclear installations at San Onofre which are practically in our back yards:

1.- From what I read in the Oceanside Blade Tribune no mention was made re. the extreme hazards and the potential of submarines from an enemy action shelling these huge nuclear concrete domes, shattering them thereby releasing that deadly nuclear radiation which could wipe out this entire area. We think this is a tremendous oversight and needs to be studied along with earthquake consideration;

1a.- A remedy in the area of earthquakes and wartime action would be to pipe some of that 100 trillion cubic feet of natural gas that CBS's 60 Minutes said exists under the U.S. continent. (President Reagan's own people admit to this). And fire the San Onofre steam boilers with the gas and eliminate all of the dangers on which you debate. I pray to God that you consider this alternative and act upon it. People's lives and health are more important than corporate profit.

2.- We believe that due to the fact that SB G&E will control only 20% of the nuclear output and Southern California Edison will control 80% and by grid move all of this 80% of this generated power to areas that are not threatened by radiation that there should be (if these plants are activated) from 60% to 30% rate discounts for people who live close to this operation. This proposal is now before the Calif. Public Utilities Commission. If you license these plants we would appreciate your recommendation to the PUC. France and Japan presently are allowing this type of discount due to the hazards of nuclear energy. So the proposal does have precedent.

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3.- To be complete and legally valid, we believe that all elements relating to the subject need to be included in the EIR. Apparently the subject of potential enemy action on these nuclear plants was not included and it needs to be discussed.

In closing may I request an answer to the positions expressed in this letter. I will be extremely grateful. I remain.

Very sincerely

Frank H. Grundel
1888 Blackhawk St.
Oceanside, Calif 92054

Perspective
TIMES-ADVOCATE
SUNDAY, JANUARY 25, 1981 C-1

Nuclear neighbor asks for discount

By DICK PHILLIPS
T-A Staff Writer

OCEANSIDE — An Oceanside man is working to achieve a considerable reduction in utility rates for those living near the San Onofre nuclear power plant.

Frank Arundel, 1888 Blackhawk St., proposed the compensation for those residents he thinks live in a danger zone — near San Onofre. He thinks they should get a 60 percent discount in electrical rates.

Residents within 30 miles should receive 50 percent rate reduction, he says, and those within a 30- to 40-mile radius a 40 percent rate reduction; people living in a 40- to 50-mile radius should have their rates cut by 30 percent.

"People here are being gouged to death by utility rates," said Arundel, 73. "With this plan, the next time they build a nuclear plant, they'll put it out of the umbrella of people where it wouldn't be troublesome in case of earthquake or war. They wouldn't put these plants at our backdoor.

"If we have to live here and bear the brunt of nuclear power, we should be beneficiaries of cheap electricity, particularly if 60 percent of the energy produced there will be transmitted outside this area anyway."

Arundel's plan did not impress the Public Utilities Commission, which has indicated there is little chance of seeing the policy implemented statewide.

The "chances of this plan flying are slim" because it would be discriminatory ratemaking, one PUC spokesman said.

San Onofre, 19 miles north of Oceanside, has one operating nuclear plant, which was shut down for repairs through most of 1980. Units 2 and 3 are nearing completion, at a cost of $2.3 to $5 billion. Both are designed to produce 1,100 megawatts of electricity.

Southern California Edison, based in Los Angeles, holds 80 percent interest in the nuclear plant and SDG&E has 20 percent. The SDG&E service area consumes about 2,300 megawatts of electricity.

Martin Mattes, legal adviser to John Bryson, PUC chairman, said copies of Arundel's proposal have been given to the commissioners for study. "But, I don't know of any action planned on the subject," Mattes said.

He said the commission reaches decisions in three ways. Under one, a consumer may apply for a rate change. "This is one way Arundel could intervene and advocate his proposal," Mattes said.

"Or, he could file a complaint against a utility for discriminatory rates, for example. But, the burden of proof is upon the complainant and it's difficult to win a case this way," Mattes said.

The commission can also initiate an investigation into an area of interest. "It's possible the PUC may decide to pursue this and investigate," Mattes said.

In his reply to Arundel, Mattes said he discussed several problems with the discounted rate plan. "If the PUC adopts rate discounts based on unfavorable aspects of having a utility company in the neighborhood, people will make other demands based on similar situations," the adviser said.

Frank Arundel: 'We bear the brunt'

For example, those living near an operating fossil fuel plant suffer because of pollution, he said. Transmission lines may be another unfavorable aspect. "The commission is already faced with substantial complications in ratemaking procedures," Mattes said.

Arundel disagrees: "If we're going to put up billions of dollars for these plants and they're going ahead and build them anyway, we should be the beneficiaries." He said 220,000 area residents would fall under the discount plan.

United States Department of Agriculture
Soil Conservation Service
2828 Chiles Road
Davis, CA 95616
(916) 758-2200

February 11, 1981

Mr. Frank J. Miraglia
Acting Chief, Licensing Branch No. 3
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Miraglia:

The Soil Conservation Service has reviewed the Supplement to the Draft Environmental Statement for San Onofre Nuclear Generating Station, Units 2 and 3. We find no controversial items within the realm of SCS responsibilities.

This Environmental Statement Supplement reveals no conflicts with any of the ongoing projects within our jurisdiction. No prime land will be lost to the proposed project.

We appreciate the opportunity to review and comment on this report.

Sincerely,

FRANCIS C. H. LUM
State Conservationist

cc: Norman A. Berg, Chief, SCS, Washington, D.C.
Jack Smith, Area Conservationist, Escondido, CA

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The Soil Conservation Service is an agency of the Department of Agriculture

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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

ER 81/80

MAR 2 1981

Mr. Frank J. Miraglia
Acting Chief
Licensing Branch No. 3
Division of Licensing
Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Miraglia:

We have reviewed the supplement to the draft environmental statement for San Onofre Nuclear Generating Station, Units 2 and 3, San Diego, California, and find we have no comments. The opportunity to review this document is appreciated.

Sincerely,

CECIL S. HOFFMANN
Special Assistant to
Assistant SECRETARY

A-55

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Attorney for Intervenors

RECEIVED
MAR 12 1981
U.S. NUCLEAR REGULATORY COMMISSION

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of SOUTHERN CALIFORNIA EDISON COMPANY, et al. (San Onofre Nuclear Generating Station, Units 2 and 3)	DOCKET Nos. 50-361 OL 50-362 OL JOINT INTERVENORS COMMENTS ON SUPPLEMEN TO DRAFT ENVIRONMENTAL STATEMENT RELATE TO OPERATION OF SAN ONOFRE NUCLEAR GENERATING STATIONS, UNITS 2 and 3 (NUREG-0490)

The Supplement to Draft Environmental Statement (NUREG-0490, December, 1980), hereinafter referred to as NUREG-0490, prepared by the Office of Reactor Regulation (Staff) of the United States Nuclear Regulatory Commission (NRC) related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3 (SONGS 2 and 3) has been reviewed by Intervenors in relation to the requirements imposed by the National Environmental Policy Act (NEPA) (42 U.S.C. § 4321, et seq.), 10 C.F.R. Part 51, and 40 C.F.R. Part 1502. Intervenors comments on the proposed action and on NUREG-0490 are made pursuant to 10 C.F.R. Part 51.25 and 40 C.F.R. Part 1503.

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The purpose of NUREG-0490 was "to identify and evaluate the site-specific environmental impacts attributable to accident sequences that lead to releases of radiation and/or radioactive materials including sequences that can result in inadequate cooling of reactor fuel and to melting of the reactor core." NUREG-0490, p. vi. These accident sequences are commonly referred to as meltdowns or Class 9 accidents.

The NRC's historic first site-specific impact study of a meltdown accident at a California nuclear reaction is inadequate, incomplete and misleading. NUREG-0490 is misleading because it does not provide decision-makers with sufficiently detailed information regarding the potential environmental impacts of a meltdown at SONGS 2 and 3 to aid them in a substantive decision whether or not to proceed with granting an operating license to this federal nuclear project in light of the economic and other consequences of an accident at SONGS 2 and 3. NUREG-0490 does not encourage public participation because it does not make adequate information available to the public in non-technical language about the potential economic and environmental impacts that could affect the lives of twelve million people. NUREG-0490 appears inadequate and incomplete when compared with other independent meltdown impact analyses.

After the Three Mile Island accident, which resulted in mass evacuations and temporary relocation of many people, the California State Legislature passed a law (Senate Bill 1183, now Section 8610.5 of the Government Code), which required the State

Office of Emergency Services (OES) to prepare Emergency Response Plans for potentially severe nuclear accidents involving the release of large amounts of radiation. In order to plan for such accidents, the State required information of the potential scenarios and consequences that could result from meltdowns in California reactors. The State lead agency, OES, contracted with a conservative consulting group, Science Applications, Inc. (SAI), to study the consequences and potential scenarios of meltdowns at California reactors. SAI has conducted research for the NRC, the Department of Energy, nuclear military projects, nuclear utilities, and the nuclear industry. The SAI-OES study was released to the public in Sacramento, California on July 15, 1980. The portion of the SAI-OES study which relates to SONGS 2 and 3 was based on extensive site-specific data whereas NUREG-0490, while it purports to be based on site-specific data, considers mainly excerpted "data, methodology and assumptions" from the WASH-1400 study. The inadequacies of this approach are demonstrated by the following comparison between the SAI-OES study and NUREG-0490 consequence analyses:

The SAI-OES study indicates that the maximum consequences for a nuclear meltdown at SONGS 2 and 3 would be $180 billion in economic cost consequences, NUREG-0490 estimates $35 billion; SAI-OES estimates 16,000 square miles of land contaminated with radiation, NUREG-0490 estimates 3,000 square miles; SAI-OES estimates eight to ten million Southern Californians would be required to relocate and leave their homes and property for up to ten years. Four to five million of them would have to be relocated longer than ten

years, NUREG-0490 gives no estimates for the magnitude of the population affected by relocation. SAI-OES estimates that in 1975 there were 7.7 million people living within 60 miles of the San Onofre site. Within 100 miles there are approximately 12 million people. The SAI-OES study acknowledges that "Latent deaths from San Onofre can occur within 100 miles, which includes half of the population of California." Another report done for the California State Legislature, discussed below, warns that children within 100 miles downwind from the reactor would receive damage to their thyroid glands and would require surgery due to exposure to radioactive iodine gases. The SAI-OES study also estimates that $6.6 billion in cost consequences could occur within 500 miles of San Onofre following a meltdown. Reports to the President's Council on Environmental Quality warn that areas as far away as 1,000 miles or more could be affected, and that up to 125,000 square miles of land could suffer some contamination or crop or milk interdiction. The possibility exists that Southern California could be permanently contaminated after a meltdown at SONGS 2 and 3. This is not surprising when we look at other accident scenarios and compare their estimates.

One NRC analysis of reactor accidents, WASH-740, estimated that an area the size of Pennsylvania could be permanently contaminated by a meltdown at a reactor significantly smaller than either Unit 2 or 3 at San Onofre. Another report, the Rasmussen report, WASH-1400, estimated that 3,000 square miles of land would be contaminated, but assumed that effective

evacuations would take place out to 30 miles downwind from the reactor accident. NUREG-0490, estimates the maximum consequences of a San Onofre meltdown to be $35 billion in costs for mitigating actions (evacuations, relocations, land interdiction, emergency response by local, county, state and federal teams), 1 million people would receive more than 25 rems, there would be 130,000 acute fatalities, and 300,000 latent cancers in the population within 50 miles who would be exposed to 30 to 40 billion person rems released during the accident.

The consequences of nuclear power plant core melt accidents have also been estimated at the request of the California State Legislature and the President's Council on Environmental Quality by Dr. Jan Beyea and Dr. Frank von Hippel, nuclear physicists with the Princeton University's Program on Nuclear Policy Alternatives of the Center for Energy and Environmental Studies. Dr. Beyea noted in his analysis that a meltdown with a release of radioactive gases from a large reactor could involve "health effects and possible land use restrictions have been considered out to distances of 1,000 miles and for periods of decades after the release." He estimates that up to 175,000 square miles of land could be under some form of interdiction or restricted use following the meltdown. He explains this by saying "The number of health effects and the . . . land contamination can range so high because a substantial fraction of the released radioactivity can be carried for hundreds of miles downwind

before being removed from the atmosphere by deposition on the ground. Dr. Beyea told the President's Council on Environmental Quality (CEQ) that "early fatalities could occur up to 30 miles downwind" of a reactor meltdown. Dr. Frank von Hippel testified before the California State Legislature after Three Mile Island that "the thyroid could receive a radiation dose tens to hundreds of times higher than the rest of the body. Exposed children more than a hundred miles downwind would suffer thyroid damage which would require surgery years later." (emphasis added) NUREG-0490 did not reference the SAI-OES study, in spite of the fact that the Atomic Safety and Licensing Board (ASLB) and the NRC Staff were made aware of the report by Intervenors during July and August of 1980, six months before NUREG-0490 was issued.

The SAI-OES study is a conservative report in that it calculates its predictions and models based on site-specific data. NUREG-0490 is not conservative and is inadequate because it is not sufficiently based on site-specific data. The SAI-OES report used extensive site-specific data regarding the nearby population centers and the various weather conditions in Southern California. That report identified several site-specific unique features which should have warranted a different conclusion from the NRC Staff than "there are no special or unique features about the San Onofre site and environs that would warrant special or additional engineered safety features for the San Onofre plants." Joint Intervenors conclude there are special and unique features that exist at the San Onofre site which are listed as follows:

(1) The three reactors at San Onofre are uniquely located near the intersection of two major Fault Zones, the Cristianitos and the Newport-Inglewood. Prior to 1980, the NRC believed there was no structural relationship between the two Fault Zones. However, in 1980, federal and state marine geologists discovered a new zone of faults which they named "Cristianitos Zone of Deformation" which project directly beneath the three reactors. Thus, the possibility of damage to the reactors during earthquakes is higher now because of the possibility of surface rupture directly under the reactors. This was not factored into the Rasmussen Report, WASH-1400, the Lewis Report, SAI-OES or NUREG-0490. NUREG-0490 does not even mention geologic-seismic site-specific events as a significantly possible factor in the probabilistic risk assessment.

(2) The San Onofre site is uniquely located on the Pacific plate, near the Plate Tectonic Boundary Fault, the San Andreas. San Onofre is moving north in relation to the North American Plate. These reactors are uniquely migrating north on a geologic time scale. Plate Tectonics were not understood when the San Onofre site was originally chosen in 1962. It was not until 1969 that the plate tectonics theories were accepted.

(3) The San Onofre site has the unique feature of being sited close to San Onofre Unit 1. If Unit 1 had a meltdown, it would severely affect operations of Units 2 and 3, resulting in various consequences, none of which were considered in NUREG-0490. The older reactor at the site, San Onofre Unit 1,

was identified by the SAI-OES analysis as having the highest probability of a meltdown of any reactor in California for two primary reasons. "The first reason is that the Unit One auxiliary feedwater system depends on operators to align and initiate the system. Potential failures due to human factors make the system less reliable than automated systems. The second reason relates the long term recirculation mode of emergency core coolant, which requires at least one of two pumps located in the containment. In the event of a pump failure, repairs cannot be made because the pump is inside the containment and would be isolated during an accident." NUREG-0490 does not consider the proximity of SONGS 2 and 3 to Unit 1 to be a unique or special feature.

(4) San Onofre Unit 1 has been shutdown for approximately one year due to leaky corroded steam generator tubes. The NRC issued a report in 1976 (NUREG-0900-5, Report to Congress on Abnormal Occurrences) which explained that "The failure of a number of steam generator tubes as a result of the pressure transients during a loss of coolant accident could render the emergency core cooling system ineffective." The Unit 1 was not designed for the magnitude of ground motions that Units 2 and 3 were. An earthquake could conceivably only damage Unit 1, because of its structurally weak steam generator tubes, but that could result in a LOCA (loss of coolant accident) and a meltdown, which would affect the two other reactors and the environment.

(5) The San Onofre reactors are special and unique in that the reactor core of Unit 2 was installed backwards, necessi-

tating total rewiring of the control room and other systems.

(6) The San Onofre site is unique also in that San Onofre Unit 2 was constructed above earthquake faults that were not discovered until 1974 during construction excavations.

(7) SONGS 2 and 3 are underlain by dewatering cavities that developed during construction. Intervenors believe this also is a special of unique feature at SONGS 2 and 3 which must be considered.

(8) The Southern California region, including San Onofre, frequently has weather inversions. During these inversions, air pollutants, including accidentally leaked radioactive gases, can be trapped beneath the inversion layer, where they can only mix and travel horizontally. Thus, a meltdown at SONGS 2 and 3 could affect the nine to ten million people who live in the air basins that share the same East Pacific high pressure zone inversion layers. Although NUREG-0490 admits that "accident consequences are very much dependent on the weather conditions existing at the time . . ." they do not specifically consider the unique Southern California high pressure inversion layers which are a predominant characteristic of the San Onofre site.

(9) The San Onofre reactors are uniquely located on a Southern California beach state park that stretches for many miles, but which is inaccessible and inescapable except by driving past the reactors on the old-highway, now running parallel to Interstate-5. On a typical summer day, 25,000 persons drive close to the reactors on a narrow and curving road. These beach-goers could be trapped during a meltdown, especially if

an earthquake occurred at the same time or caused it.

(10) Another unique or special feature of San Onofre is its proximity to roads used by thousands of uncontrolled travelers per day which presents a unique possibility for sabotage accidents that could lead to releases of radioactivity.

(11) The San Onofre site is special and unique in that one-half of the population of the State of California lives within 100 miles of the site.

(12) It is a unique feature of SONGS 2 and 3 to be the largest reactors ever considered for operating licenses.

(13) The San Onofre site is unique in that it is sited within contamination distance of a major portion of the nation's fresh produce farms, especially in the winter months.

(14) The San Onofre site is also unique in that it could cause international economic and environmental impacts by contamination of a significant part of Baja California's agricultural resources.

After the Kemeney Commission and the Rogovin Report were issued on Three Mile Island, the Council on Environmental Quality wrote a letter to the Nuclear Regulatory Commissioners on March 20, 1980. The letter released the results of the CEQ review and critized the NRC's lack of compliance with NEPA laws in the EIS analyses of potential accidents at reactors. The CEQ stated that the NRC's EIS discussions of "potential accidents and their environmental impacts was found to be largely perfunctory, remarkably standardized, and uninformative to the public." The CEQ also advised the NRC that "site specific treatment of data

should be substituted for "'boilerplate' assessment of accident initiating events and potential impacts, and EIS's should be comprehensible to non-technical members of the public..." Intervenors comment upon the fact that NUREG-0490 contains 29 pages of text with about 8 pages of site-specific information which is selective and slanted. NEPA requires detailed statements of aspects of proposed action significantly affecting the quality of the human environment and Intervenors feel NUREG-0490 is inadequate in that it is"largely perfunctory, remarkably standardized and uninformative to the public."

NUREG-0490 is also inadequate in that it failed to consider earthquake induced core melt accidents. While the Reactor Safety Study(RSS), WASH-1400, concluded that the probability of core melt accidents in nuclear power plants from seismic events was insignificant compared to core melt probabilities from other accidents, recent assessment of the potential for earthquake induced core melt accidents suggests that the probability of such events may be significant when compared to core melt accidents from other causes considered by RSS. Intervenors contend that the seismic design basis for SONGS 2 and 3 is inadequate and, therefore, consider it prudent to evaulate the potential for seismic-induced core melt accidents at SONGS 2 and 3 to establish if they may be significant factors. The purpose of NUREG-0490 was to identify and evaluate site-specific environmental impacts. It does not evaulate the potential for seismic-induced core melt accidents and, therefore its probabilistic assessment of risk at SONGS 2 and 3 is inadequate.

NUREG-0490 is further inadequate and particularly misleading in its assessment of health affects avoidance (Section 7.1.1.4). NUREG-0490 did not mention thyroid blocking in its assessment of health affects avoidance, relying only on restriction of contaminated property and foodstuffs. Dr. Frank von Hipple in his testimony before the California State Legislature states:

> The thyroid can be protected against absorbing radioiodine, however, if before the cloud arrives you take about one thousand times your ordinary daily iodine intake in the form of potassium iodide (the form of iodine present in iodized salt). This will saturate the thyroid with ordinary iodide and reduce its ability to absord the radioactive iodide when it arrives. This strategy was recommended in the American Physical Society's reactor safety study four years ago. The Food and Drug Administration approved potassium iodide for emergency thyroid 'blocking'. . . I would recommend that California do two things with regard to this thyroid protection strategy:
>
> 1) Develop a stockpile of potassium iodide in the appropriate dosage in either sealed foil wrapped pills or liquid solution. This would not be costly. Based on a 1972 study for the Defense Civil Preparedness Study, it appears that enough pills for the entire nation could be produced for a few million dollars.
>
> 2) The more difficult part of the job would be to develop an effective distribution system. If one waited until a cloud of radioiodine had been released before distributing the blocking chemical and informing the public of its use, one might well be too late. (A week after the beginning of the crisis at Three Mile Island, the Pennsylvania state government refused to distribute the chemical to the population within 10 miles of the site - despite the joint recommendation to do so from the Surgeon General, the Food and Drug Commissioner, and the Director of the National Institutes of Health who thought that sufficient warning time might not be available to protect this population in case a release occurred. On the other hand, if people were given potassium iodide to keep in their medicine cabinets along with asprin, it is likely that many would lose track of it pretty quickly. Perhaps it should be attached by the local utility to household electricity meters and its presence announced in case of need. The best strategy is obviously a problem well worth a study. California could break some important ground here."

Section 7.1.1.4. is particularly misleading in its statement that "radiation hazards in the environment tend to disappear by the natural process of radioactive decay (but) can continue for a relatively long period of time -- months, years or <u>even decades</u>." (emphasis added) This misleading statement fails to note that some ratioactive wastes from nuclear accidents such as radioactive Strontium and Cesium can enter the food chain and remain a hazard for 1,000 years or more. Other isotopes remain a hazard for 1 million years or more.

NUREG-0490, Section 7.1.3. entitled Mitigation of Accident Consequences is inadequate in that it fails to note that consequences could be reduced by retrofitting SONGS 2 and 3 with filtered venting systems to prevent accidental releases of radioactive gases.

NUREG-0490, Section 10 is misleading, inadequate and incomplete. The Section contains three sentences with regard to its conclusions and Re-Evaluated Benefit-Cost Balance. This section should be expanded because the environmental risks of a Class 9 accident involve the entire region of Southern California, Norther Baja California, Mexico, and parts of Arizona. These regions could be permanently contaminated with radiation following a coremelt at SONGS 2 and 3. The risks involve the

value of all real and personal property, both public and private in those regions. The risks involve fatalities, latent cancer deaths and genetic damage. The risks involve compensation to victims in the event of such accidents. Section 10 of NUREG-0490 concludes that the environmental risks of Class 9 - coremelt accidents - "does not change the results of the cost-benefit balance contained in the Draft Environmental Statement (Section 10)."

CONCLUSION

NUREG-0490 concludes "that there are no special or unique features about the San Onofre site and environs that would warrant special or additional engineered safety features for the San Onofre plants." Intervenors conclude there are unique characteristics at SONGS 2 and 3 that warrant additional engineered safety features especially in light of the unique earthquake hazard which could cause a coremelt accident and common-cause failure of essential safety systems at SONGS 2 and 3. A future earthquake near the San Onofre site could be the common cause for failure of the cooling systems of all three reactors on the San Onofre site and all three of the spent fuel pools simultaneously. This would be the worst case accident that should be analyzed by the NRC and this analysis should be a part of a revised NUREG-0490.

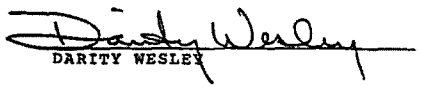
CERTIFICATE OF SERVICE

I hereby certify that the JOINT INTERVENORS COMMENTS ON SUPPLEMENT TO DRAFT ENVIRONMENTAL STATEMENT RELATED TO OPERATION OF SAN ONOFRE NUCLEAR GENERATING STATIONS, UNITS 2 AND 3 (NUREG-0490) have been served on the following by deposit in the United States mail, first class, postage prepaid, this 9th day of March, 1981:

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Director, Division of Licensing

Executed on March 9, 1981 at San Diego, California.



DARITY WESLEY

Union of
CONCERNED
SCIENTISTS

9 March 1981

RECEIVED
MAR 12 1981
U.S. NUCLEAR REGULATORY COMMISSION

Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Director, Division of Licensing

Dear People:

Re: Supplement to the Draft Environmental Statement (NUREG-0490) related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3

Herewith are some brief comments on the above Supplement, in response to your invitation.

We are pleased that the NRC has finally published a document providing a hint of the consequences of severe accidents at the San Onofre Station. We consider, however, that this Supplement does not satisfy the intent of the Commission's Statement of Interim Policy of 13 June 1980 (Federal Register, 45, 40101). Nor does this Supplement provide the public with information sufficient to make a reasoned assessment of the risks of severe accidents at this plant.

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You will recall that the Commission's Statement of Interim Policy followed a letter of 20 March 1980 from the Chairman of the Council on Environmental Quality (CEQ) to the Chairman of the NRC. Included in this letter was the statement:

> "The results of our review of impact statements prepared by the NRC for nuclear power reactors are very disturbing. The discussion in these statements of potential accidents and their environmental impacts was found to be largely perfunctory, remarkably standardized, and uninformative to the public."

This Supplement must be substantially revised and improved before it overcomes these CEQ criticisms. For guidance during this process of revision and improvement, the NRC staff should consult the report "NRC's Environmental Analysis of Nuclear Accidents: Is It Adequate?", prepared for CEQ by the Environmental Law Institute (ELI) in February 1980. A copy of this

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report was provided to the NRC with the CEQ Chairman's letter.

Part 5 of the ELI report recommends that the NRC should continue, with some substantial improvements, its previous practice of studying a selection of accident scenarios. The ELI report recommends that this selection should be expanded to include "Class 9" accidents. Section 7 (Environmental Impact of Postulated Accidents) of the San Onofre Draft Environmental Statement (dated November 1978) exemplifies this previous practice; it estimates radiation doses for a number of selected accidents in Classes 1 through 8. This Supplement, however, merges nine release categories, weighted by assumed probabilities. The results of this analysis are confusing for the public; one might suspect that this is by intention.

Each accident scenario should be considered alone. For each scenario, the NRC should provide a clear account of:

(i) the nature of the postulated accident

(ii) the estimated nature of the radioactive release

(iii) the estimated nature of the environmental consequences of that release.

The Commission's Statement of Interim Policy directs:

> " . . . approximately equal attention shall be given to the probability of occurrence of releases and to the probability of occurrence of the environmental consequences of those releases."

This Supplement does not satisfy the intent of that directive. It merges these two probabilities although they are of quite different natures. One might suspect that this approach is selected in order to persuade the public that severe consequences have extremely low probabilities. This form of analysis and presentation does not fulfill the NRC's obligation to accurately inform the public.

As the NRC staff should well know, probabilities in nuclear accident analysis fall into two distinct categories:

(i) probability of occurrence of release
This category of probability concerns engineering estimates. These are very difficult to make since there is a limited statistical base and much of the uncertainty relates to human behaviour.

(ii) probability of occurrence of environmental consequences, given a particular release

This category of probability concerns factors such as wind speed and direction. These factors can be estimated from a good statistical base.

The NRC staff should revise this Supplement so as to exhibit their estimates of these probabilities separately, within each accident scenario studied.

The Commission's Statement of Interim Policy also directs:

> " . . . consequences shall be characterized in terms of potential radiological exposures to individuals, to population groups, and, where applicable, to biota."

This Supplement does not fulfill the intent of that directive. It provides very limited information on the geographical variation of potential exposure. More seriously, it provides essentially no information on the significance of exposure for different population groups. As the NRC staff should well know, certain population groups (especially children and fetuses) are at greater risk for a given release.

The importance of revising this Supplement, so as to accurately inform the public, can be illustrated by two estimates which can be gleaned from the supplement itself:

(i) probability of occurrence of the "PWR2" core melt accident

This release is one of the most severe accidents considered in the Reactor Safety Study (WASH-1400) and this Supplement. Table 7.1.4-2 of the Supplement estimates its probability as 7×10^{-6} per reactor-year. Section 7.1.4.2 concedes that this estimate could be low by a factor of 100. One thus finds (assuming a reactor life of 30 years) that this Supplement admits that a "PWR2" accident could have a 4% probability of occurrence during the life of San Onofre Units 2 and 3.

(ii) potential for serious health effects

Table 7.1.4-4 of this Supplement admits that a severe accident at San Onofre could lead to 130,000 acute fatalities, 300,000 subsequent fatal cancers, and 600,000 genetic effects.

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In the light of the grave hazard shown by these estimates, the NRC has a clear duty to provide the public with more complete information than is contained in this Supplement.

Thank you for your attention.

Sincerely,

G.R. Thompson

Gordon Thompson, Ph.D.
Staff Scientist

GT:VN

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
215 Fremont Street
San Francisco, Ca. 94105

RECEIVED MAR 20 1981 U.S. NUCLEAR REGULATORY COMMISSION

16 MAR 1981

Project # DS-NRC-K06002-CA

Frank J. Miraglia, Acting Chief
Licensing Branch No. 3
Division of Licensing
Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Miraglia:

The Environmental Protection Agency (EPA) has received and reviewed the Draft Supplement (DS) to the Draft Environmental Impact Statement (DEIS) for the project titled SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3.

In our previous reviews of environmental documents dealing with Light Water Reactors (LWR) EPA has consistently emphasized the need for a thorough evaluation of the environmental impacts from different LWR accident scenarios to include Class 9 accidents. The discussion of the environmental and societal impacts of a core melt down accident included in the Supplement to the Draft Environmental Impact Statement for the San Onofre Nuclear Generating Station, Units 2 and 3 is a step forward in this respect and, as a result, EPA applauds the Nuclear Regulatory Commission's (NRC) decision to prepare this Supplement.

The assessment of environmental impacts for severe accidents at the plant uses methodologies originally developed in the Reactor Safety Study (WASH-1460) and the Liquid Pathway Generic Study (NUREG-0440). Because these two studies will be the cornerstones for similar assessments for other nuclear power plants environmental statements, we would refer NRC to EPA's original technical comments on these studies. These comments can be found in "Reactor Safety Study (WASH-1400): A Review of the Final Report" and a letter from EPA's Office of Federal Activities to NRC dated February 8, 1977.

Our specific comments on the San Onofre Supplemental DEIS and generic comments are attached. The EPA appreciates the opportunity to comment on this Draft Supplement. Should the NRC choose to revise other sections of the EIS, EPA would like to review these documents. If you have any questions regarding our comments, please contact Susan Sakaki, EIS Review Coordinator, at (415)556-7858.

Sincerely yours,

Jake Mackenzie, Director
Surveillance and Analysis Division

Attachment

A-65

8103230423

EPA Technical Comments on the Supplement to the Draft Environmental Statement Related to the Operation of the San Onofre Generating Station Units 2 and 3 (NUREG-0490)

General Comments

The Final EIS for San Onofre Units 2 and 3 is dated March 1973. This statement contains a Section 7, titled "Environmental Impact of Postulated Accidents." It is not clear if the Supplement is to replace the original information or if the Supplement is supplemental. If this information is supplemental then we would suggest that the original Section 7 be revised to agree with the supplemental statements and data.

It would also be hoped that any previous information and conclusions would be revised if it is impacted by events occurring since 1973 or by a change in Commission consideration. For instance the supplement refers to the original Section 5.5 and further mentions 10 CFR Part 20 and 10 CFR Part 50. However, the supplement does not make any mention of the Commission's implementation of 40 CFR 190 for normal operation.

Specific Comments

Table 7.1.4-4

This table should correspond on a one-to-one basis with the release categories (PWR 1-9) in Table 7.1.4-2. It is also not readily apparent how the PWR 1-9 compares to the original Table 7.1.

Design Basis Accidents

In the discussion of accident risk and impact assessment of Design Basis Accidents (DBAs), Section 7.1.4.1, we do not understand the intent of the comparison of the results in Table 7.1.4-1 to the Reactor Site Criteria of 10 CFR 100. First, the infrequent accidents listed in Table 7.1.4-1 do not meet the requirements of 10 CFR 100 for purposes of site analysis. Footnotes to 10 CFR 100 state:

> (1)...calculations should be based upon a major accident, hypothesized for the purposes of site analysis...that would result in potential hazards not exceeded by those from any accident considered credible, and
>
> (2)...this 25 rem whole body value and the 300 rem thyroid value have been set forth as reference values, which can be used in the evaluation of reactor sites with respect to potential reactor accidents of exceedingly low probability of occurrence, and low risk of public exposure to radiation.

Secondly, by the description of infrequent accidents in the supplement ("events that might occur once during the lifetime of the plant"), these accidents have an annual probability of occurrences on the order of 10^{-2}, are considered credible, and are not of exceedingly low probability of occurrence. Reference to 10 CFR 100 and its implementation provide a misleading inference that, since the results shown in Table 7.1.4-1 are within the dose values of 10 CFR 100, the risk of those infrequent accidents is small and therefore acceptable. Also, the radiation doses listed in Table 7.1.4-1 are calculated using a conservative model approach which is relevant to safety evaluations and not consistent with the realistic approach to the assessment of environmental risks of normal operation and severe core melt accidents.

The discussion of impacts of infrequent accidents and limiting faults, in both the original DES and the Supplement, addresses probabilities of occurrence qualitatively. Yet, in the discussion of the more severe core melt accidents the probabilities of occurrence are quantified (Table 7.1.4-2). For consistency in the presentation of all environmental risks, the probabilities of occurrence of infrequent accidents and limiting faults DBA's should also be provided.

It is not clear whether the risks listed in Table 7.1.4-5, Annual Average Values of Environmental Risks Due to Accidents, include those from infrequent accidents and limiting faults (Table 7.1.4-2), postulated accidents (Table 7.2 of the original DES), and accidents leading to the PWR 1-9 release categories (Table 7.1.4-2). The risks should include all those from moderate frequency accidents, infrequent accidents, limiting faults and severe core melt accidents. Although the risk of the infrequent accidents and limiting faults is "judged to be extremely small" and appear to be overshadowed by the risk from core melt accidents, they should be fully presented. The risks from the more probable yet lower consequence accidents may indeed be significant to the individual risk and should be listed in the Supplement. It would also be beneficial to extend Figures 7.1.4-3, 7.1.4-5, and 7.1.4-7 to include the higher probability accidents.

It would be helpful to provide a summary table of the annual average value of environmental risks from operation of all the reactors at the San Onofre site. The risks

should include all those from normal operations, moderate frequency accidents, infrequent accidents, limiting faults and severe core melt accidents. Both societal and individual risks should be presented.

7.1.1.3 Health Effects

The statement that a dose greater than about 25 rem is necessary before any physiological effects to an individual are clinically detectable should be reviewed. Information contained in a World Health Organization technical report No. 123 would seem to indicate that physiological changes can occur at exposures as low as 10 rem.

7.1.3.3 Emergency Preparedness

It is unclear what is the basis of the statement, "Emergency preparedness plans including protective action measures for the San Onofre facility and environs are in an advanced, but not yet fully completed stage." The plans (seven) are at this date undergoing informal review by the Region IX Regional Assistance Committee (RAC). Thus, there has been no request for formal review, there has been no drill schedule established and there has been no full scale exercise. We do not concur in the Commission's statement that these plans are in an advanced stage.

Table 7.1.4-5

It is not clear from the information presented regarding risk and protective action that protective actions can be taken to reduce exposures by 10-20 times or in fact to prevent exposures determined by the State of California to be unacceptable considering the following:

1. The emergency preparedness plans and protective action measures for the San Onofre facility are not yet complete.
2. The State of California does not use the EPA's Protective Action Guides (PAG's).

In view of the above, we feel the statements made are premature.

Figure 7.1.4-8

This figure, "Relative Directional Risk to Individuals," might be a useful risk analysis. However, as presented, the figure is illegible and lacking in background information. It should be presented more clearly, with an accompanying table or coding explaining the significance of the numbers.

Decommissioning

The cost of reactor decommissioning and replacement power costs are as large as the costs from the Three Mile Island accident. It would seem that these costs could significantly change the cost-benefit information originally provided in Section 13. Future EIS's or Supplements to EIS's should include an evaluation of these costs.

A-67

San Diego
ASSOCIATION OF
GOVERNMENTS
Suite 524, Security Pacific Plaza
1200 Third Avenue
San Diego, California 92101
(714) 236-5300

March 19, 1981

Mr. Dino C. Scaletti
San Onofre Project Manager
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Dear Mr. Scaletti:

On March 16, 1981, the Board of Directors of the San Diego Association of Governments (SANDAG) adopted a resolution supporting the operation of San Onofre Nuclear Power Plant Units 2 and 3 and requested the Nuclear Regulatory Commission to grant an operating license for these units subject to federal regulations regarding the safety of nuclear power plant operations and emergency planning for nuclear power plant accidents. This resolution and the supporting staff report are attached.

Please call me or have your staff call Steve Sachs of my staff if you have any questions about the Board of Directors action.

Sincerely,

for RICHARD J. HUFF
Executive Director

RJH/SS/sc

Attachments

cc: Patricia Fleming, SDG&E
Fred Massey, SCE

A-68

MEMBER AGENCIES: Cities of Carlsbad, Chula Vista, Coronado, Del Mar, El Cajon, Imperial Beach, La Mesa, Lemon Grove, National City, Oceanside, Poway, San Diego, Santee, County of San Diego

San Diego ASSOCIATION OF GOVERNMENTS

RESOLUTION

No. 81-36

RESOLUTION SUPPORTING THE OPERATION
OF SAN ONOFRE NUCLEAR POWER PLANT
UNITS 2 AND 3
SUBJECT TO FEDERAL REGULATIONS REGARDING THE
SAFETY OF NUCLEAR POWER PLANT OPERATIONS AND
EMERGENCY PLANNING FOR NUCLEAR PLANT ACCIDENTS

WHEREAS, the Energy 2000 Task Force, appointed by Mayor Wilson of the City of San Diego, presented the conclusions and recommendations of its report to the SANDAG Board of Directors on February 23, 1981; and

WHEREAS, one of the recommendations of the Energy 2000 Task Force is to support the completion and operation of San Onofre Plants 2 and 3; and

WHEREAS, San Onofre Units 2 and 3, if completed and operated on schedule, will supply approximately half of the additional electricity needs forecast for the San Diego region between now and 1995; and

WHEREAS, the Nuclear Regulatory Commission will begin licensing hearings for San Onofre Units 2 and 3 in June 1981; and

WHEREAS, federal regulations concerning nuclear power plant safety and emergency response planning will have to be met in order for a license to be granted; NOW THEREFORE

BE IT RESOLVED that the Board of Directors supports the operation of San Onofre Nuclear Power Plant Units 2 and 3 and requests the Nuclear Regulatory Commission to grant an operating license for these units subject to federal regulations regarding the safety of nuclear power plant operations and emergency planning for nuclear plant accidents.

PASSED AND ADOPTED this 16th day of March 1981.

ATTEST: _____ SECRETARY

_____ CHAIRMAN

MEMBER AGENCIES: Cities of Carlsbad, Chula Vista, Coronado, Del Mar, El Cajon, Imperial Beach, La Mesa, Lemon Grove, National City, Oceanside, Poway, San Diego, Santee, County of San Diego

SAN DIEGO ASSOCIATION OF GOVERNMENTS

RESOLUTION NO. 81-36 DATE CONSIDERED: 3/16/81

AGENCY	YES	NO	ABSENT	ABSTAIN
CARLSBAD	X			
CHULA VISTA	X			
CORONADO	X			
DEL MAR		X		
EL CAJON	X			
IMPERIAL BEACH	X			
LA MESA	X			
LEMON GROVE	X			
NATIONAL CITY	X			
OCEANSIDE	X			
SAN DIEGO	X			
SAN MARCOS	X			
SANTEE	X			
VISTA	X			
TOTALS	13	1		

I certify from personal observation and count that the above results are an accurate record of the SANDAG Board of Directors vote and action.

Betty Black

A-69

San Diego Association of Governments

BOARD OF DIRECTORS

DATE: March 16, 1981 AGENDA REPORT No.: R-95

CONSIDERATION OF SUPPORT FOR OPERATION OF
SAN ONOFRE NUCLEAR POWER PLANT UNITS 2 AND 3

Introduction

The Board requested this report as the basis for considering a resolution to support the operation of San Onofre Nuclear Power Plant Units 2 and 3. Three important points the Board should consider before taking a position are:

- The risks to health and life of both present and future generations and the costs of reducing these risks associated with almost all aspects of the nuclear fuel cycle, are extremely controversial. There is little scientific or technical consensus on the severity of the risks and the effectiveness or cost of strategies to reduce these risks.

- San Onofre Units 2 and 3 would provide 440 MW of electric power to the San Diego region - almost one-half of the additional power requirments forecast to be needed between now and 1995 for the SDG&E Service Area by SDG&E and the California Energy Commission. These forecasts include the effects of existing conservation and alternative energy source programs which will reduce electricity demand. Potential additional electricity supplies and conservation and alternative energy sources which could result in a balance between demand and supply over the next 10 to 20 years without San Onofre Units 2 and 3 have been identified (see attachment for a partial list) but are not yet committed. In some cases, these sources may be infeasible or unavailable.

- The construction of San Onofre Units 2 and 3 is nearing completion. About one-half of the total $3.4 billion projected construction cost has been expended. The plant is currently undergoing U.S. Nuclear Regulatory Commission review in order to obtain an operating license.

It is my

RECOMMENDATION

that the Board of Directors support the operation of San Onofre Nuclear Power Plants 2 and 3 and request the Nuclear Regulatory Commission to grant an operating license for these units subject to federal regulations regarding the safety of nuclear power plant operations and emergency planning for nuclear plant accidents.

Discussion

San Onofre Units 2 and 3 are scheduled to have a total capacity of 2,200 megawatts (MW) of electricity. SDG&E is a 20% partner in the plan. is therefore entitled to 440 MW of the electricity generated. The other 1,760 MW is scheduled to be used by Southern California Edison Company (76%) and Municipal Utilities serving the Cities of Anaheim and Riverside (total of 4%).

The Nuclear Regulatory Commission (NRC) is the federal agency responsible for issuing nuclear power plant operating licenses. The NRC will hold hearings on the license applications for San Onofre Units 2 and 3 starting in June 1981.

There are many environmental and economic issues related to the operation of San Onofre Units 2 and 3 which include:

- Cost and reliability of nuclear power
- Risk of accidents from transport of uranium, spent nuclear fuel and operation of the plants.
- Cost of decommissioning the plants.
- Ability of the plants to withstand earthquakes.
- Hazards, cost and technical feasibility of long-term storage of radioactive wastes.
- Scope and adequacy of emergency plans to reduce radiation exposure in the event of an accident.

At the licensing hearings in June, it appears that the most controversial issues will be the ability of the plants to withstand earthquakes and the adequacy of emergency planning in case of an accident that could impact surrounding areas. The Plant must meet federal standards in both of these areas before a license will be issued.

RICHARD J. HUFF
Executive Director

A-70

San Diego ASSOCIATION OF GOVERNMENTS

RESOLUTION

No. 81-36

RESOLUTION SUPPORTING THE OPERATION
OF SAN ONOFRE NUCLEAR POWER PLANT
UNITS 2 AND 3
SUBJECT TO FEDERAL REGULATIONS REGARDING THE
SAFETY OF NUCLEAR POWER PLANT OPERATIONS AND
EMERGENCY PLANNING FOR NUCLEAR PLANT ACCIDENTS

WHEREAS, the Energy 2000 Task Force, appointed by Mayor Wilson of the City of San Diego, presented the conclusions and recommendations of its report to the SANDAG Board of Directors on February 23, 1981; and

WHEREAS, one of the recommendations of the Energy 2000 Task Force is to support the completion and operation of San Onofre Plants 2 and 3; and

WHEREAS, San Onofre Units 2 and 3, if completed and operated on schedule, will supply approximately half of the additional electricity needs forecast for the San Diego region between now and 1995; and

WHEREAS, the Nuclear Regulatory Commission will begin licensing hearings for San Onofre Units 2 and 3 in June 1981; and

WHEREAS, federal regulations concerning nuclear power plant safety and emergency response planning will have to be met in order for a license to be granted; NOW THEREFORE

BE IT RESOLVED that the Board of Directors supports the operation of San Onofre Nuclear Power Plant Units 2 and 3 and requests the Nuclear Regulatory Commission to grant an operating license for these units subject to federal regulations regarding the safety of nuclear power plant operations and emergency planning for nuclear plant accidents.

PASSED AND ADOPTED this 16th day of March 1981.

ATTEST: _____ SECRETARY

_____ CHAIRMAN

MEMBER AGENCIES: Cities of Carlsbad, Chula Vista, Coronado, Del Mar, El Cajon, Imperial Beach, La Mesa, Lemon Grove, National City, Oceanside, San Diego, San Marcos, Santee and Vista/Ex-officio Member. California Department of Transportation/Honorary Member. Tijuana, B. C. N.

ATTACHMENT
(From Energy 2000 Task Force Report)

Potential Supply Alternatives
For the SDG&E Service Area*
1980-2000

San Onofre 2 and 3	440 MW (nuclear)
Arizona (renewed contract)	400 MW (imported)
New Mexico (renewed contract)	150 MW (imported)
Washington (renewed contract)	100 MW (imported)
Mexico (purchase)	300 MW (imported)
Geothermal	800 MW (geothermal)
Blythe site	1,000 MW (coal gasification)
Hydroelectric	34 MW (hydroelectric)
Cogeneration	100 MW (cogeneration)
Wind	30 MW (wind)
TOTAL	3,354 MW

SOURCE:

San Diego Gas and Electric Company, September 1979

*Some of these sources may be infeasible or unavailable. For example, Arizona Public Service Company would have to agree to a renewed contract for 400 MW of imported power from Arizona; the feasibility of 1000 megawatts from a coal gasification plant at Blythe has not been proved.

A-71

Southern California Edison Company

P O BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD CALIFORNIA 91770

K. P. BASKIN
MANAGER OF NUCLEAR ENGINEERING, SAFETY, AND LICENSING

TELEPHONE
(213) 572-1401

March 24, 1981

RECEIVED MAR 27 1981 U.S. NUCLEAR REGULATORY COMMISSION

Director, Office of Nuclear Reactor Regulation
Attention: Darrel G. Eisenhut, Director
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Sir:

Subject: Docket Nos. 50-361 and 50-362
San Onofre Nuclear Generating Station
Units 2 and 3

References: Realistic Estimates of the Consequences of Nuclear Accidents, M. Levenson and F. Rahn, EPRI, November, 1980.

This letter provides Southern California Edison Company's comments to the Supplement to Draft Environmental Statement related to the operation of San Onofre Nuclear Generating Station Units 2 and 3 NUREG-0490. In our review of this document we have found two points which we feel are in need of further clarification prior to the issuance of a Final Environmental Statement.

1. The following statement contained in Section 7.1.4.3,

> "The 200-rem whole-body dose figure corresponds approximately to a threshold value for which hospitalization would be indicated for the treatment of radiation injury. The 25-rem whole-body (which has been identified earlier as the lower limit for a clinically observable physiolgical effect) and 300-rem thyroid figures correspond to the Commission's guideline values for reactor siting in 10 CFR Part 100."

requires clarification, to prevent the statement from being misconstrued to state that San Onofre does not meet the Commission siting guidelines of 10 CFR 100.

In order to clearly differentiate between the Class 9 accident and the design basis accidents used in the Commission siting criteria, specific clarification is needed. The traditional Design Basis Accidents (DBA's) are hypothetical and conservative scenarios, evaluated in accordance with regulations and other regulatory guidance which define the required assumptions and methodology. In contrast, the Class 9 accident scenario is defined with no consideration of mitigation by engineered safety features, assumes highly conservative and consequence maximizing behavior of natural mitigation processes. Since the Class 9 accident uses much more conservative, unrealistic, assumptions, it is not considered in the evaluation of reactor siting.

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2. Although uncertainties in probability calculations are discussed in Sections 7.1.4.2 and 7.1.4.7 of the Supplement, the uncertainties in the source terms, and hence the consequences of the accident, are not discussed in either Section 7.1.4.3 or 7.1.4.7. These radiation source terms have been shown to be conservative by experiments performed at Rockwell, Karlsruke, Oak Ridge National Laboratory, General Electric (Aircraft Nuclear Propulsion Department), Bettis National Laboratory, Hanford National Laboratory, and tests performed in the Idaho Reactor Test Site. The results of these tests and experiments, summarized in a paper by M. Levenson and F. Rahn of the Electric Power Research Institute, indicate that natural processes are operating which prevent the release of radioactive nuclides from molten nuclear reactor fuel (Reference 1). Dr. Chauncey Starr, former President of the Electric Power Research Institute advised the Commission, at the Commissions November 18, 1980 meeting in Washington, D.C., that,

> "The important issue is that the initial review of this subject appears to indicate that under any conceivable realistic circumstance, the real source term is likely to result in risk to the public that is less by factors of 10 to 100 than that which was previously estimated."

Using Dr. Starr's estimate of a realistic maximum release into the atmosphere would lower the consequences (acute fatalities and cancer deaths) from a Class 9 accident by 1 to 2 orders of magnitude.

The Final Environmental Statement for San Onofre Units 2 and 3 should be accurate, concise, and not leave room for misinterpretation. Where applicable, all sources of error, and the relative magnitude of error, should be indicated. We hope that these comments will help to make the FES for SONGS 2 and 3 such a document.

Very truly yours,

K P Basu

A-72

APPENDIX B

NEPA POPULATION DOSE ASSESSMENT

Appendix B

NEPA POPULATION DOSE ASSESSMENT

Population dose commitments are calculated for all individuals living within 80 km (50 miles) of the facility employing the same models used for individual doses (see Regulatory Guide 1.109, in preparation). In addition, population doses associated with the export of food crops produced within the 80-km region and the atmospheric and hydrospheric transport of the more mobile effluent species such as noble gases, tritium, and carbon-14 have been considered.

B.1 NOBLE GAS EFFLUENTS

For locations within 80 km of the reactor facility, exposures to these effluents are calculated using the atmospheric dispersion models in Regulatory Guide 1.111 and the dose models described in Section 5.5 and Regulatory Guide 1.109. Beyond 80 km and until the effluent reaches the northeastern corner of the United States, it is assumed that all of the noble gases are dispersed uniformly in the lowest 1000 m (3280 ft) of the atmosphere. Decay in transit was also considered. Beyond this point, noble gases having a half-life greater than one year (e.g., Kr-85) were assumed to mix completely in the troposphere of the world with no removal mechanisms operating.

Transfer of tropospheric air between the northern and southern hemispheres, although inhibited by wind patterns in the equatorial region, is considered to yield a hemisphere average tropospheric residence time of about two years with respect to hemispheric mixing. Since this time constant is quite short with respect to the expected mid-point of plant life (15 years), mixing in both hemispheres can be assumed for evaluations over the life of the nuclear facility. This additional population dose commitment to the U.S. population was also evaluated.

B.2 IODINES AND PARTICULATES RELEASED TO THE ATMOSPHERE

Effluent nuclides in this category deposit onto the ground as the effluent moves downwind, which continuously reduces the concentration remaining in the plume. Within 80 km of the facility, the deposition model in Regulatory Guide 1.111 was used in conjunction with the dose models in Regulatory Guide 1.109. Site-specific data concerning production, transport, and consumption of foods within 80 km of the reactor were used. Beyond 80 km, the deposition model was extended until no effluent remained in the plume. Excess food not consumed within the 80-km distance was accounted for, and additional food production and consumption representative of the eastern half of the country was assumed. Doses obtained in this manner were then assumed to be received by the number of individuals living within the direction sector and distance described above. The population density in this sector is taken to be representative of the eastern United States, which is about 410 persons per km^2 (160 persons per mi^2). (This approach is conservative for San Onofre because population densities in the western United States are considerably lower than those in the eastern portion.)

B.3 CARBON-14 AND TRITIUM RELEASED TO THE ATMOSPHERE

Carbon-14 and tritium were assumed to disperse without deposition in the same manner as krypton-85 over land. However, they do interact with an atmospheric residence time of 4 to 6 years with the oceans being the major sink. From this, the equilibrium ratio of the carbon-14 to natural carbon in the atmosphere was determined. This same ratio was then assumed to exist in man so that carbon-14 to natural carbon in the atmosphere was determined. This same ratio was then assumed to exist in man so that the dose received by the entire population of the United States could be estimated. Tritium was assumed to mix uniformly in the world's hydrosphere, which was assumed to include all the water in the atmosphere and in the upper 70 m (230 ft) of the oceans. With the model, the equilibrium ratio of tritium to hydrogen in the environment can be calculated. The same ratio was assumed to exist in man, and was used to calculate the population dose, in the same manner as with carbon-14.

B.4 LIQUID EFFLUENTS

Concentrations of effluents in the receiving water within 80 km of the facility were calculated in the same manner as described above for the Appendix I calculations. No depletion of the nuclides present in the receiving water by deposition on the bottom of the Pacific Ocean was assumed. It was also assumed that aquatic biota concentrate radioactivity in the same manner as was assumed for the Appendix I

evaluation. However, food consumption values appropriate for the average individual, rather than for the maximum, were used. It was assumed that all of the sport and commercial fish and shellfish caught within the 80-km area were eaten by the U.S. population.

Beyond 80 km, it was assumed that all of the liquid effluent nuclides except tritium have deposited on the sediments so they make no further contribution to population exposures. The tritium was assumed to mix uniformly in the world's hydrosphere and to result in an exposure to the U.S. population in the same manner as discussed for tritium in gaseous effluents.

APPENDIX C

EXPLANATION AND REFERENCES FOR BENEFIT-COST SUMMARY

Appendix C

EXPLANATION AND REFERENCES FOR BENEFIT-COST SUMMARY

C.1 ECONOMIC IMPACT OF STATION OPERATION

C.1.1 Direct benefits

C.1.1.1 Energy

2114 MWe x 1000 kW/MW x 365 days x 24 hr/day x capacity factor (0.5 or 0.7). This product ranges from 9.3 x 10^9 kWhr/year (0.5 capacity factor) to 13.0 x 10^9 kWhr/year (0.7 capacity factor).

C.1.1.2 Reduced regional oil consumption

Section 8.3.1 shows that the applicants primarily have oil/gas fired units, which would have to be operated to a greater extent if SONGS 2 & 3 are not operated. The additional fuel oil consumption (assuming a 50% capacity factor for the nuclear units) is calculated as follows:

$$\frac{9.3 \times 10^9 \text{ kWhr} \cdot 9{,}000 \text{ Btu/kWhr} \cdot 1 \text{ bbl oil}}{6.29 \times 10^6 \text{ Btu}} = 13.2 \times 10^6 \text{ bbl oil.}$$

C.1.2 Economic costs

C.1.2.1 Fuel

From Sect. 8.3.1, the staff's estimate of fuel cost is $10.8 per megawatt-hour in 1983. Assuming a 60% capacity factor or 11.1 x 10^6 MWhr/yr gives the value in Table 10.1.

C.1.2.2 Operating and maintenance

Using the staff's OMCST computer code, operating and maintenance costs are estimated to be 4.05 mills/kWhr at 60% capacity, which multiplied by 11.1 x 10^9 kWhr/year gives the values in Table 10.1.

Decommissioning: Based on estimates given in Sect. 9.4, the cost of decommissioning each unit will be $66.7 million in 1978 dollars or $85.4 million in 1980 dollars at the end of the useful life of the plant. If this value is discounted from 2013 to 1983, then annualized over a 30-year life assuming a real interest and discount rate of 4.76%, and then multiplied by 2 units, the value in Table 10.1 is obtained.

APPENDIX D

CULTURAL RESOURCES

STATE OF CALIFORNIA—THE RESOURCES AGENCY EDMUND G. BROWN JR., Governor

DEPARTMENT OF PARKS AND RECREATION
P.O. BOX 2390
SACRAMENTO 95811
(916) 445-8006

DEC 18 1980

Mr. Dino Scaletti
Environmental Projects
Division of Site, Safety,
and Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Scaletti:

San Onofre Nuclear Generating Station,
Units #2 and #3, Operating License Stage

My staff has recently completed review of the "National Register Assessment Program of Cultural Resources of the 230 KV Transmission Line Rights-of-Way from San Onofre Nuclear Generating Station to Black Star Canyon and Santiago Substation and to Encina and Mission Valley Substation", prepared by WESTEC Services, dated September 1980.

In accordance with the provisions of the Advisory Council on Historic Preservation's Procedures set forth in 36 CFR 800, Section 106 of the National Historic Preservation Act of 1966 and the Memoranda of Agreement of October 29, 1979, I have the following comments to offer:

1. Based on the information I have been provided, I concur that the following sites are not eligible for National Register of Historic Places: CA-Ora-419, Ora-823, Ora-786, Ora-787, Ora-700, Ora-782, Ora-784, Ora-785, Ora-832, SDi-6693, SDi-6131, SDi-5444, SDi-6136, SDi-6137, SDi-6150, SDi-6151, and SDi-6152.

2. Sites CA-Ora-640, Ora-458, and SDi-6133 are outside the area of potential environmental impact for this undertaking.

3. I do not concur that site CA-Ora-824 is not eligible for the National Register of Historic Places. I feel that this site may be eligible based on Bean and Vane's findings in 1979 that this site possesses a high potential for significance.

4. I concur that the following sites are eligible for inclusion in the National Register as important components of the proposed San Joaquin Archeological District: CA-Ora-495, Ora-496, and Ora-499.

5. The following sites have been determined eligible for inclusion in the National Register as important components of the Upper Aliso Creek Archeological District: CA-Ora-447, Ora-438, and Ora-725.

6. The following sites should also be included as eligible properties within the Upper Aliso Creek Archeological District: CA-Ora-905, Ora-828, Ora-825, Ora-826, and Ora-827.

7. I concur that the following sites are eligible for inclusion in the National Register as significant components of the proposed Santiago Creek Archeological District: CA-Ora-829, Ora-830, and Ora-831.

8. I concur that the following sites are eligible for inclusion in the National Register as significant components of the proposed Agua Hedionda Archeological District: CA-SDi-6135, SDi-6133, and SDi-6140.

9. I also concur that the following sites are locally significant and are eligible for the National Register under Criterion "d" (36 CFR 1202.6): CA-Ora-498, SDi-4538, SDi-6130, SDi-6138, and SDi-6149.

10. Formal determinations of eligibility for these sites and districts should be sought from the Keeper of the Register in accordance with 36 CFR 1204.

11. I concur with the report's findings that this undertaking will have No Effect on eligible sites CA-Ora-905, Ora-828, Ora-826, Ora-827, Ora-829, and SDi-4538.

12. I concur with the report's findings that operation and maintenance (O&M) of access roads will affect the following eligible sites: CA-Ora-498, Ora-824, Ora-495, Ora-447, Ora-496, Ora-499, Ora-825, Ora-725, Ora-830, Ora-831, and SDi-6130. However, I feel that there will no No Adverse Effect on these resources if one of the two following conditions can be met:

    a. Access roads can be covered with a chemically inert, visually distinguishable fill within the boundaries of these sites in a manner which will preclude future ground disturbance of the cultural deposit during future O&M activities on access roads, or;

    b. O&M activities can be restricted to access roads, and the remaining research potential of surface artifacts within the provenience of existing access roads can be used to define the important factors which should be considered in determining the effects of continued disturbances as proposed in the Cultural Resource Management Plan on page 359 of the subject report. This program should be oriented towards defining the value of research potential and the effects that various activities may have on disturbed surface sites in similar environmental contexts. The program should also be responsive to the Advisory Council's Supplementary Guidance for Treatment of Archeological Properties supporting a No Adverse Effect Determination.

13. The information I have been provided indicates that undisturbed cultural deposits will be affected by O&M of access roads in the vicinity of site CA-Ora-438. However, it is my opinion that there will be No Adverse Effect if one of the two following conditions can be met:

    a. Access roads can be covered with a chemically inert, visually distinguishable fill within the boundaries of this site in a manner which will preclude future ground disturbance of the cultural deposit during future O&M activities, or;

    b. O&M activities can be restricted to access roads, and a Data Recovery Plan is implemented in accordance with the Advisory Council's Supplementary Guidance for Treatment of Archeological Properties supporting a No Adverse Effect Determination. The rationale for this recommendation is stated in the above referenced Guidance on pages 10 and 11, "An Undertaking may be taken to have no adverse effect...if the agency is committed to a data recovery program...if...the property is shown to be subject to destruction and deterioration regardless of the undertaking, so the agency's action is only slightly hastening a process that is inevitable in any event."

14. O&M activities and construction will have an effect on sites CA-SDi-6135, SDi-6138, SDi-6149, and SDi-6140. However, it is my opinion that there will be No Adverse Effect on these sites if a Data Recovery Plan is implemented in accordance with the Advisory Council's Supplementary Guidance for Treatment of Archeological Properties supporting a No Adverse Effect Determination. The rationale for this recommendation is the same as that cited in Item 13.b. above.

15. Concurrence of these determinations of effect should be sought from the Advisory Council in accordance with 36 CFR 800.4.c.

If you should have any questions, please contact Daniel Bell of my staff at (916) 322-8702.

Sincerely,

Knox Mellon

Dr. Knox Mellon
State Historic Preservation Officer
Office of Historic Preservation

D-6317D

cc: Mr. L. Jack Brunton
Licensing and Environmental Department
San Diego Gas and Electric Company
P.O. Box 1831
San Diego, CA 92112

Mr. David White
Southern California Edison Company
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Ms. Roxanna Phillips
WESTEC Services, Inc.
3211 Fifth Avenue
San Diego, CA 92103

Mr. Charles Niquette
Advisory Council on Historic Preservation
Lake Plaza-South, Suite 616
44 Union Boulevard
Lakewood, CO 80228

APPENDIX E

CALIFORNIA COASTAL COMMISSION, MARINE REVIEW COMMITTEE REPORT

CALIFORNIA COASTAL COMMISSION
631 Howard Street, San Francisco 94105 — (415) 543-8555

TO: State Commissioners

FROM: Michael Fischer, Executive Director

SUBJECT: Report of San Onofre Nuclear Power Plant Marine Review Committee (For Commission consideration at the February 17-19 Meeting.)

Summary

The 1974 permit for the San Onofre Nuclear Power Plant's Units 2 and 3 established a three member Marine Review Committee (MRC) to study the effects of the Plant's cooling system on ocean life and to make recommendations to the Commission. Units 2 and 3 of the Plant are not yet operational. The MRC has submitted a report (conclusions attached) predicting effects on fish, kelp, plankton and other ocean life. The MRC recommends against any design changes to the cooling sustem at this time. Staff recommends the Commission take note of the MRC recommendations and endorse a future monitoring program to determine actual effects on ocean life in the future after system operation. If substantial adverse effects are found, the Commission can impose design or operational changes or mitigation measures, based on MRC recommendations. But, given MRC predictions, major system design changes in the future seem unlikely.

E-1

Background

The Commission's predecessor Coastal Zone Commission approved the construction of Units 2 and 3 of the San Onofre Nuclear Generating Station (SONGS) on February 20, 1974 (Permit No. 183-73). Condition B of the Permit provided for the establishment of an applicant funded Marine Review Committee (MRC) composed of an appointee of the State Commission, an appointee of Southern California Edison Company, and an appointee of the appellants. The appellants are coordinated by Friends of the Earth. The Condition provides for the MRC to undertake a "comprehensive and continuing study of the marine environment offshore from San Onofre...to predict, and later to measure, the effects of San Onofre Units 2 and 3 on the marine environment..." (Condition B1).

The MRC can make recommendations to the Commission, based on MRC studies, and the recommendations can include changes that the MRC believes necessary in the cooling system for Units 2 and 3. This cooling system takes in large amounts of seawater to cool the units and then discharges the heated water back to the ocean. Condition B6 of the Permit states:

> Should the study at any time indicate that the project will not comply with the regulatory requirements of State or Federal water quality agencies, or that substantial adverse effects on the marine environment are likely to occur, or are occurring, through the operation of Units 1, 2, and 3, the applicants shall immediately undertake such modifications to the cooling system as may reasonably be required to reduce such effects or comply with such regulatory requirements (which can be made while construction is going on and could be as extensive as requiring cooling towers if that is the recommendation). The State Commission shall then further condition the permit accordingly.

Thus, the Commission can impose new conditions on the cooling system only if the conditions are based on MRC recommendations and the Commission judges the conditions to be "reasonable". New conditions can be based only on an MRC finding that "substantial adverse effects on the marine environment are likely to occur, or are occuring, through the operation on Units 1, 2, and 3...."

Since its beginning, the MRC has submitted a number of reports to the Commission. After receiving an MRC report in mid-1979 the Commission, at its November 21, 1979 meeting, asked the MRC to take one final "best shot" at predicting effects on the marine environment prior to the start of Nuclear Regulatory Commission (NRC) hearings on the operating license for Units 2 and 3. The MRC has now submitted that report, MRC Document 80-04(I). The conclusions are attached to this staff report, and the MRC will present the conclusions to the Commission at its January 20-22 meeting.

Staff Analysis

The Marine Review Committee has, over the last six years, conducted monitoring and predicting studies that seem to be as comprehensive and thorough as possible given the state-of-the-art in predicting effects on the large and dynamic nearshore ocean environment. It is possible that the square kilometer offshore SONGS is the most heavily sampled and studied patch of the ocean anywhere. Predicting the effects of the SONGS cooling system on ocean life has had to face a number of inherent difficulties, including: understanding the life cycles of ocean organisms; obtaining enough samples over a long enough time period to enable statistical analyses; developing quantitative models of water flows, turbidity and population dynamics; and, most important, attempting to separate out effects or likely effects of the cooling system from other major factors affecting ocean life, including storms, water temperature and chemistry changes, fishing, changes in nutrient levels, changes in migratory habits, and natural population fluctuations.

Design Changes. The MRC has needed to use models and numerous assumptions in assessing possible effects on living ocean populations. Such exercises can give scenarios, but not high confidence predictions. The MRC report consequently presents a number of estimates of future effects on fish larvae, small shrimp, plankton, and and a kelp bed. It does not, however, state that these effects are likely or certain to occur, and, therefore, it does not state that "substantial adverse effects on the marine enviroment are likely to occur", as required in Condition B6 for modification of the cooling system. The report, then, explicitly recommends against design changes in the cooling system at this time, while stating "it is possible that we have grossly underestimated the ecological consequences of SONGS Units 1, 2, and 3" (Page 7). The actual effects can only be determined through monitoring the ocean environment after the Units become operational. The MRC has extensive results from pre-operational sampling and data collection and will be in a position to implement a useful post-operational monitoring program. Staff is therefore recommending the Commission endorse a continued MRC monitoring program and ask that the program design and budget be submitted to the Commission. If the MRC finds "substantial adverse effects" the Commission may still impose conditions accordingly.

Mitigation. One such condition could involve mitigation for damage determined by the MRC. The Commission directed the MRC to explore mitigation alternatives. This last attempt at predictions has taken up most MRC time, and the MRC report states it will recommend to the Commission which mitigation measures, in addition to artificial reefs for kelp, should be examined.

Radiological Monitoring. A 1979 MRC report detailed a number of inadequacies in the radiological monitoring program in the ocean around SONGS. The Commission directed staff to report these inadequacies to the Southern California Edison Co., the Nuclear Regulatory Commission, and the California Department of Health Services and to pursue remedies. SCE has since revised its radiological monitoring program extensively and has submitted it to the NRC. Both the NRC and the MRC author of the previous report are evaluating the revised program at present.

Staff Recommendation

Staff recommends the Commission adopt the following resolution:

The Commission thanks the Marine Review Committee for the report "Predictions of the Effects of San Onofre Nuclear Generating Station and Recommendations", adopted unanimously by the members of the MRC. The Commission notes that the MRC does not predict at this time that substantial adverse effects on the marine environment are likely to occur fron the operations of the SONGS cooling system, and that the MRC recommends against system design changes at this time. However, the Commission also notes that the MRC states it may have grossly underestimated these effects. Tha Commission agrees, therefore, that the MRC should conduct a comprehensive and thorough monitoring program of the effects after SONGS becomes operational and requests that the MRC submit the design and cost of such a program to the Commission. If such monitoring discovers substantial adverse effects on the marine environment, the Commission can, at that time, based on MRC recommendations, impose new conditions including design or operating changes or mitigation measures. The Commission recognizes, given the MRC predicted effects of the cooling system, that future imposition of any major design changes to the cooling system is unlikely.

F-2

marine review committee

Office: (805) 961-3104
DEPT. OF BIOLOGICAL SCIENCES
UNIVERSITY OF CALIFORNIA
SANTA BARBARA, CA 93106

November 17, 1980

RECEIVED
NOV 2 8 1980
CALIFORNIA
COASTAL COMMISSION

Mr. Bill Ahearn
California Coastal Commission
4th Floor
631 Howard Street
San Francisco, California 94105

Dear Bill:

This letter formally transmits to the California Coastal Commission, under separate cover, the Marine Review Committee's predictions concerning the effects of San Onofre Units 1, 2 and 3 upon the marine ecosystem. The Report also contains a study of options and a set of recommendations to the Commission. These predictions and recommendations have been agreed upon unanimously by the Committee. The Appendices will follow in approximately two weeks.

A later report will discuss mitigation in more detail.

Yours sincerely,

Rimmon C. Fay

Rimmon C. Fay

Byron Mechalas

William W. Murdoch
(Chairman)

REPORT OF THE MARINE REVIEW COMMITTEE TO THE CALIFORNIA COASTAL COMMISSION: PREDICTIONS OF THE EFFECTS OF SAN ONOFRE NUCLEAR GENERATING STATION AND RECOMMENDATIONS

PART I: RECOMMENDATIONS, PREDICTIONS, AND RATIONALE

Marine Review Committee

William W. Murdoch, Chairman
University of California

Byron J. Mechalas
Southern California Edison Company

Rimmon C. Fay
Pacific Bio-Marine Labs, Inc.

MRC Document 80-04(I)

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INTRODUCTION

The Marine Review Committee was charged, in Permit No. 183-73 of the California Coastal Commission, to carry out "a comprehensive and continuing study of the marine environment offshore from San Onofre . . . to predict, and later to measure, the effects of San Onofre Units 2 and 3 on the marine environment, . . . in a manner that will result in the broadest possible consideration of the effects of Units 1, 2 and 3 on the entire marine environment in the vicinity of San Onofre." This Report responds to the charge to predict the effects of Units 2 and 3.

San Onofre Nuclear Generating Station (SONGS) Unit 1 has been operating since 1968. Almost 150 billion gallons of seawater per year circulate through the Plant. Water flows in through a single intake and is discharged through a single discharge pipe at 19°F above the intake temperature. The construction of SONGS Units 2 and 3 is virtually completed. Each has a single intake, each drawing in seawater at a rate of 830,000 gallons per minute, which will result in an estimated flow of almost 700 billion gallons per year. Each also discharges its heated effluent through a series of 63 diffuser ports set along a kilometer-long pipe that tapers from 18' to 10'-14' in diameter (Figure 1, Maps 1 and 2). This discharged water moves rapidly towards the surface, entraining and moving with it roughly 10 times its own volume of water. As it spreads, this water mass moves various distances offshore, depending upon the prevailing currents. MRC has measured these currents, and Southern California Edison has produced a physical model of SONGS' water movement.

The effects of the cooling system of Unit 1 upon the marine ecosystem were described in MRC Annual Reports for 1978 and 1979. The documented effects are restricted to a region within a kilometer or two of SONGS. In seeking to predict the effects of Units 2 and 3, MRC has looked at the loss of organisms taken into the intakes, the possible losses caused by water movements driven by the diffuser plumes, and the effects of the diffusers and heat treatments on the physical environment, and hence upon the biota.

The predictions presented in this Report are in most cases close to final. Although we can and will obtain some more information on the major parts of the ecosystem near SONGS before Units 2 and 3 begin operation, we have obtained most of the information it is possible to obtain with a feasible expenditure of effort. Where major uncertainties remain, further study will not in general resolve them; they are largely an inescapable result of the practical difficulties in studying real ecological systems, and of the nature of such systems. The exceptions are kelp, where future work should provide more, and important, information, and some modelling studies that have not yet been completed. At this point, however, future work on predictions is aimed mainly at guiding our monitoring studies.

Following this Introduction, the Report presents our recommendations. There follows a brief statement of predictions for each major part of the community, and a more extensive Rationale, which explains how we arrived at the predictions. The Rationale unavoidably contains some technical discussion, but we have tried to write it so that the reader unfamiliar with the study can follow it. Finally, a series of separate Appendices accompanies this Report. These appendices are the reports of various contractors, and

analyses (by MRC and its consultants) of a number of difficult technical issues. The Rationale refers to those Appendices, where necessary, by project, number and, if appropriate, page number.

We would like to stress two findings that have general importance for management of and planning for nearshore coastal waters in California. First, we reiterate a previous conclusion that, in open coastal situations, a diffuser design is likely to be ecologically more damaging than a single point discharge, even though the latter would violate present State thermal discharge standards.

Second, we have recently obtained evidence that the early (larval) stages of nearshore sport and commercial fish species (e.g. bass, halibut) are particularly sparse very close to shore, while the larvae of fodder fish species are abundant right into shallow waters. Fodder fish populations are probably better able than sport and commercial species to withstand additional mortality on their larval stages. If this pattern holds along the whole California coast, it should be used as basic information in future planning - e.g. the placement of intakes and outfalls. This is not a blanket recommendation for placing structures close to shore, but rather a recommendation to weigh the possible losses of fish larvae in such decisions.

OPTIONS AND RECOMMENDATIONS

Options

San Onofre Kelp bed (SOK) and nearshore fish populations are the major parts of the marine ecosystem that SONGS Units 1, 2 and 3 could significantly harm. Mysids, and perhaps zooplankton, are of less direct interest to society, but they also might sustain significant and quite large impacts. In the light of the predictions, MRC reviewed a number of possible recommendations that could be made to the Commission:

1. Make no design changes at this time. Monitor the effects.
2. Make no design changes at this time. Examine the feasibility of mitigating some or all of the effects, with a view to recommending mitigation measures to the Commission.
3. Extend the intake pipes to beyond the 30 meter depth.
4. Redesign the diffusers of Units 2 and 3, to convert them to single point discharges, located either 4 to 5 km offshore or very close inshore.
5. Convert the once-through cooling system to cooling towers.

Option 1 would require only a monitoring program, which would be carried out over several years to determine the effects of SONGS on the marine ecosystem. This program, in addition, would generate important information for future coastal planning, and would test how well we can predict the ecological consequences of a major coastal installation.

Option 2 MRC has completed a short "paper" feasibility study of certain kinds of mitigation (Mitigation Appendix). This study describes various methods of enhancing the production of economically important species, such as reef fish and abalone. Southern California Edison has

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established an experimental reef aimed at producing a kelp bed and associated organisms, including fish and abalone. Other mitigation measures may be feasible.

It should be stressed that mitigation could not be expected to replace completely the biota lost through SONGS' operation. San Onofre Kelp bed could perhaps be replaced by a similar kelp bed, but fish losses would probably be replaced (partially) by a somewhat different mix of species. Lost mysids and plankton are not likely to be replaced by any known mitigation measure. An adequate mitigation study would therefore need to address the acceptability of "replacing" losses of one species by increasing the production of another.

Option 3 The possibility of extending the intakes out to deeper water was suggested previously (MRC 1979 Interim Report) as a means of (1) reducing the turbidity of intake water, so that the effects on SOK would be reduced, and (2) reducing the kill of nearshore fish larvae. With regard to aim (1), the turbidity study (Turbidity Appendix) suggests that much of the turbid water passing over SOK will originate at the inshore segment of the diffusers and will be carried offshore by secondary entrainment, so that the gain from changing the intakes would be relatively small. With regard to aim (2), our recent analyses show that the larvae of nearshore sport and commercial species are relatively sparse in the present intake area, and are quite dense out to about 7 km offshore. The gain in moving the intakes offshore would therefore be mainly a reduction in fodder fish kills, while we would likely kill more of sport and commercial species.

Option 4 The diffusers carry turbid water over the kelp bed. They

also will cause an unknown, but probably significant, amount of mortality in mysids, plankton and fish larvae. A single point discharge would greatly reduce this latter mortality, and moving the discharge either close inshore or further offshore would remove the kelp bed from the influence of the discharge. A single point discharge would violate the State thermal tolerances, but MRC believes this would cause much less ecological damage than the diffusers. It might be possible to make practical use of the waste heat from an inshore discharge. MRC has not evaluated in detail the ecological consequences of these two alternatives.

Recommendations

We recommend Options 1 and 2, and recommend against design changes at this time (Options 3, 4 and 5).

Monitoring is needed to measure the effects of Units 1, 2 and 3, as required by the Permit. It is also essential that the effects are measured and compared with MRC's quantitative predictions. Part of our study is a unique effort to make such predictions, and it is only by testing them that we can determine if such prediction is possible, how accurate it is, and what changes are needed to make better predictions in future planning. Predictions of probable effects, whether made explicit or not, are of course an integral part of all coastal planning.

We also recommend that MRC's remaining and ongoing prediction efforts be completed. These are now small studies. Such quantitative predictions are important, not only in themselves, but as a guide to the future monitoring program.

It is important to monitor the success of Southern California Edison's experimental reef, now established some 5 km south of SONGS. The evidence

on the efficacy of reefs, especially as a basis for new kelp beds, is equivocal and in contention, and this experiment will allow us to judge the best available California reef technology. MRC will present to the Commission, at a later date, a recommendation on whether or not other mitigation measures should be examined.

We recommend against moving the intake pipes (Option 3), for the reasons given under that Option. We also recommend against Options 4 and 5 at this time. Destruction of the offshore portion of the kelp bed is a major possible effect of the diffusers. However, at this moment we are not certain this will occur, and it is also possible that the effect could be mitigated. Some mitigation of fish losses may also be possible.

It is possible that we have grossly underestimated the ecological consequences of SONGS Units 1, 2 and 3. If monitoring proves this to be the case, we will re-examine the possibility of recommending major design changes.

PREDICTIONS

FISH

Introduction

Most fish caught in Southern California are netted by commercial fishermen, and most come from fishing areas more than a few kilometers off the coast. By contrast, most sport fish in Southern California are caught close to the land - within the 33 California Fish and Game "fishing blocks" that are contiguous with the shore. In this Report we are concerned mainly with those sport fish and with commercial catches taken close to shore, for it is only this nearshore group of fish that SONGS is expected to affect. In evaluating the predictions, therefore, it should be kept in mind that SONGS is not expected to influence the great bulk of the fish populations that are harvested by California fishermen.

The species that concern us are fish that live as adults mainly within about 4 or 5 km of shore and that produce planktonic (drifting) eggs and larvae in the same zone. Among these species there are two groups: the nearshore sport and commercial species, the harvest of which is made up mainly by halibut, white seabass, kelp bass and sand bass, and the nearshore fodder fish (or forage fish) that form a major portion of the prey of the sport and commercial species.

In the predictions, we present various numbers to help the reader evaluate the likely effects of SONGS. It is easy to misinterpret these numbers, and we give here some essential background information. If we know the abundance and sizes of all of the halibut, say, in some area along the

coast, we can calculate the total living weight (biomass) of halibut in that region. This is called the standing stock. Each year, there are additions to this standing stock - some individuals that were larvae grow up to become adults, and many of those already adult grow and gain weight. If we could add up all the accumulated growth (in weight) we would be able to say how much new biomass had been added to the population. This is the annual production of new halibut tissue. We cannot estimate this directly, but a general rule of thumb is that a sport and commercial population gains about 60% of its standing stock weight per year. If our harvesting techniques were perfect we could take all of this production each year as harvest, and keep the standing stock steady from one year to the next. However, inevitably some fish die of disease and parasites, others are eaten by predators, and so on. The annual harvest, therefore, is always less than the annual production. In these nearshore sport and commercial species near San Onofre we estimate the harvest is roughly a quarter of production.

As long as the harvest plus other factors do not take more than the annual production, the population will not decline. However, if, on average, harvest plus other losses are greater than production, the population will decline. If they are less than production, the population will increase, until it approaches a limit (say its food supply), at which time production will begin to decline and the population will level off.

We stress that the numbers given below are in all cases approximate. They give us an indication of the likely size of effects, but they do not tell us precisely what losses will be.

Predictions

1. Nearshore Sport and Commercial Fish

It is probable that, because of SONGS' activities, somewhere between 27 and 60 tons of nearshore sport and commercial fish production will be lost annually (Table 1). We feel the lower figure is more probable than the upper figure. Halibut is the species that will be most affected. Fish move about, so any loss of production will be spread over some area. We do not know how large an area, and provide a comparison between the consequences of spreading the loss over a small (45 km) and a large (300 km) stretch of coastal waters.

A loss of 27 tons would be equivalent to about 6% of the annual production of nearshore sport and commercial fish in the four fish blocks covering about 45 km of coastline near SONGS. It is equivalent to about one-third of the most recently documented (1975) harvest of these species from these four fishing blocks (85 tons). This does not mean that all of the losses will occur in these four blocks, or that the harvest can be expected to decline by either 6% or one-third.

If the losses were to be spread evenly over 300 km (about three-quarters of the length of the California Bight), then the loss in annual production over this area would be 1%. The loss in harvest could be more than 1% of that caught over 300 km. For example, to take an extreme case, if all natural losses are unavoidable, then all of the loss would come out of the harvest, which, for the 1975 harvest, would decline by roughly 10%.

There is quite strong evidence that the stocks of nearshore sport and commercial fish (especially halibut) have declined in the past two decades. We believe that these populations are unlikely to be able to compensate for

(i.e. make up for) significant additional mortality. However, the projected loss of sport and commercial fish, caused by SONGS, is sufficiently small that we believe it will not, in itself, have a significant effect on these populations.

Although SONGS alone is expected to have a minor effect upon the populations of nearshore sport and commercial fish, the cumulative effect of a number of sources of mortality of this order would be expected to contribute to continued decline in these populations. Future planning in the California Bight, therefore, should not evaluate additional installations and other environmental insults as independent events, but should consider their cumulative effects.

2. Fodder Fish

Anchovies probably contribute more than any other species to the diet of nearshore sport and commercial fish. Although enormous numbers of anchovy larvae will be killed by SONGS, we do not expect this vast population to be affected as a result of the operation of SONGS.

Nearshore fodder fish species are also important in the diets of nearshore sport and commercial fish. The two most abundant nearshore fodder fish are queenfish and white croaker. SONGS is expected to cause a loss in production of nearshore fodder fish of at least 300 tons per year.* Unlike the sport and commercial species, there is no evidence that the fodder fish populations are declining, so that we could expect some compensation for these losses. We do not know how much, so we cannot predict a precise net loss. Fodder fish in general move around more than sport and commercial species, and the populations in the entire Bight may well be thoroughly

*All weight figures are wet weight and are in metric tons.

mixed, so that losses would be spread over the Bight (roughly 400 km). If the losses were spread over the Bight, and if no compensation occurred, they would be equivalent to about 7% of the annual production of these fish.

The projected loss of the equivalent of 300 tons of fodder fish production is owing mainly to the loss of larvae in the intakes. We expect there will be additional losses caused by the diffusers carrying larvae to inhospitable environments offshore. These losses could be very large - greater than those caused by the intakes - but we cannot predict them accurately.

The projected intake losses alone are sizeable. While we cannot estimate how the populations will be affected (because we do not know enough about compensation), the accumulation of effects of this order would be expected eventually to cause declines in these stocks. Thus, while SONGS itself may not cause such declines (and we do not know whether it will or not), we would be concerned about accumulating additional losses of this magnitude in the future.

We expect that the direct impingement of juvenile and adult fodder fish (mainly queenfish) in the intakes will cause measurable changes in the age structure and sex ratio of this species to a distance of several kilometers from SONGS.

3. Mechanisms

Fish losses are caused by three main mechanisms: (1) direct impingement of juvenile and adult fish in the intakes, (2) loss of immature stages (especially larvae) in the intakes, and (3) loss of immature stages in the diffusers. Mechanisms (2) and (3) are the most important. The diffusers could kill larvae (a) through subjecting them to turbulent shear and (b) by

carrying inshore larvae to an inhospitable environment offshore (translocation).

Intake losses: Our recent analyses have yielded a critical piece of information that may be important in the placement of intakes. We have evidence that the larvae of nearshore sport and commercial fish species are unlike most nearshore larvae and are quite sparse very close to shore where the intakes are. Because of this peculiar distribution, we estimate the loss of sport and commercial fish production, owing to larval mortality via the intakes, to be only 20 tons per year, rather than 160 tons per year as previously expected, thus reducing the predicted impact to one that is relatively minor.

Diffuser losses: We estimate that relatively few fish larvae will be killed by turbulent shear, and believe that this will be a minor effect. We also do not expect the larvae of sport and commercial species to suffer translocation mortality in the plume. However, translocation may cause very large losses of fodder fish larvae.

4. Upwelling Effects of SONGS

SONGS' diffusers will bring extra nutrients to the surface, and move them offshore. This could result each year in the production of roughly 460 tons of anchovy. We believe this will have a negligible effect on sport and commercial fish production, and virtually no effect on nearshore sport and commercial fish production.

Table 1. Summary of predicted effects of SONGS Units 1, 2 and 3 upon nearshore fish species. Numbers are metric tons per year.

	In biomass	In production	In sport and commercial production
(1) Losses by direct impingement of juvenile and adult fish in intakes			
Fodder fish	31-51	25-41	0-4
Sport and commercial fish	7-12	4-7	4-7
Electric rays	7-13	5-8	---
Other fish	5-8	3-5	---
		Subtotal	4-11
(2) Losses by kill of planktonic stages in intakes			
Fodder fish	358	287	3-29
Sport and commercial fish	34	20	20
		Subtotal	23-49
(3) Damage to kelp bed	0-9	0-3	0-3
		TOTAL	27-63

KELP

Introduction

Kelp beds constitute a distinct and important habitat in the nearshore marine ecosystem in Southern California. Over 760 species of animals (invertebrates and fish) and over 120 species of plants have been found in kelp beds in Southern California. At least two fish species (kelp perch and kelp rockfish) are rarely found outside of kelp beds, and many invertebrate species occur most commonly in this habitat. In the San Onofre kelp bed (SOK) alone we have recorded 164 species of animals and 16 species of plants - certainly an underestimate of the actual diversity. In the three local kelp beds (SOK, San Mateo kelp and Barn kelp) we have recorded 384 species of animals and 36 species of plants. Kelp beds are highly productive of sport fish, including the highly valued kelp bass.

Kelp plants grow very rapidly, and as plants die, or parts of plants break off, they produce food for bottom-dwelling animals. In December 1978, for example, SOK produced an estimated 9 tons of detritus per day.

San Onofre is in an area where kelp beds are (now) rather scarce. However, the local beds maintain ecological continuity between the more extensive beds to the north and south.

Historically, San Onofre kelp bed has exhibited two states: (a) the "normal" state in which much of the available rocky substrate is covered by kelp as is now the case, but the degree of cover varies; (b) periods following catastrophic die-offs of adult plants, during which the bed is non-existent, at very low coverage, or is recovering.

Predictions

(1) It is likely that SONGS Units 2 and 3 will alter the normal state by reducing the density of kelp plants in the offshore portion of the bed. This is the major area of the bed. The reduction could be very small or very large. There are several confounding factors which prevent us from stating a most likely extent of reduction in abundance at present.

(2) SONGS probably will lengthen the periods during which the bed is absent, or very sparse, following catastrophic die-offs.

(3) We expect to see some reduction in the abundance of shrimp species in the canopy in a portion of the kelp bed. No quantitative prediction is possible. This change could alter the diets of fish in the bed.

Mechanisms

Turbidity: SONGS will affect the bed mainly by increasing the turbidity downstream from the points of discharge. This increase will be small in summer, but in spring it is predicted to lower light levels in the water column. The reduction at the bottom in the offshore portion of the bed is predicted to be about 40%. The lower light intensities that result will probably reduce the frequency of successful recruitment of young kelp plants. It is also likely to reduce the growth of kelp plants. Both effects are likely to reduce both the biomass of kelp in the bed and the number of plants.

Fouling: SONGS' plumes are also likely to increase the degree of fouling of kelp plants by various invertebrates that settle on to and live on kelp. Increased turbidity, and perhaps turbulence, are among the mechanisms that could increase fouling. Fouling is likely to 1) decrease the rate

of kelp growth, 2) increase the rate of loss of parts of the plant, and 3) perhaps increase the death rate of plants.

Sea Urchins: Urchin populations may also be increased because SONGS will increase the supply of particulate organic matter that the urchins can use as food. Our studies show that urchins kill a large fraction of kelp plants in parts of the bed, and they probably also interfere with recruitment by grazing on small, young kelp plants.

Sedimentation: The operation of SONGS is not expected to alter the sedimentation rate in SOK.

Temperature: Temperature changes caused by the SONGS plume will be small and are not likely to affect the bed significantly.

Nutrients: Part of the time, the concentration of nutrients may be somewhat increased in the water surrounding adult kelp plants, as a result of upwelling via entrainment. This may increase the growth rate of kelp plants.

Competitors: When kelp is removed from the substrate other plants and animals can grow in its place. These organisms may prevent or slow the re-colonization of kelp, by taking up the space. Although we have information on these organisms, it is not possible to predict whether SONGS will significantly influence these interactions.

Toxic Substances: During the course of the studies at SONGS, circumstantial evidence has been found for the existence of toxic materials in the discharged water from Unit 1. We can make no definitive statement as to whether or not such toxic substances will be discharged by Units 2 and 3, except that chlorine will continue to be used on an intermittent basis.

MYSIDS

Introduction

Mysids are small shrimp-like creatures that live in shallow water just above the ocean floor, or amongst kelp canopy and other benthic algae. At night some of them rise several meters into the water column, and at this time they are more likely to be entrained by SONGS. Unlike true plankton, they can swim against weak currents, and so can maintain their position to some extent.

Mysids were chosen as a target organism for several reasons.

1) They have similar biology to a number of other groups of "hypo-plankton" that live close to the bottom.

2) They are important food items for a number of fodder fish (e.g. queenfish), which in turn are fed on by sport and commercial fish.

3) Like a number of plankton species, some mysid species live only close to shore and will be taken into the SONGS cooling system and will also be transported offshore by the diffusers. However, since they have a longer generation time than plankton, they are likely to recover more slowly from such extra mortality, and are therefore more likely to show local depressions in density. Mysids are therefore expected to be a good "marker" group for the effects of SONGS.

Predictions

1. Our mysid studies indicate that we should see a reduction in density of about 50% for several kilometers away from SONGS, and smaller depressions on the order of 10 km long. There are several factors that prevent us from

being certain about these effects. First, we are forced to make assumptions about the numbers killed by the diffusers, since we cannot measure this loss. Second, we do not know how strong compensation will be.

2. SONGS intakes will kill several billion mysids per year, weighing 50-60 tons. The diffusers could kill several hundred tons of mysids. If, for example, 10% of those entrained by the diffusers were killed by being carried offshore to unfavorable habitat, the annual kill would be rather less than 200 tons. We are unable, at the moment, to give a most probable estimate of diffuser losses.

Mysids constitute about one-half of the total of epibenthic organisms that are subject to entrainment. A similar mortality rate for all of this group would thus give an annual kill of all organisms of this type of about 350 tons.

If these 350 tons were lost to the fodder fish, we could expect an annual loss of fodder fish production on the order of 30 tons. However, the MRC fish study group believes that much of the mysid biomass killed and moved offshore will be eaten by these same fish species in the region of the diffusers. Some mysid material will, of course, fall uneaten to the ocean floor. There it will join food webs that lead in part to benthic fish. These food webs are less efficient than the mysid → fodder fish chain, so we could expect some overall loss of fodder fish production, although much less than 30 tons per year. We do <u>not</u> predict, therefore, that the mysid losses will have a significant effect on sport and commercial fish production.

PLANKTON

Introduction

The plankton is made up mainly of small drifting organisms that are generally moved about passively by currents. Phytoplankton are single-celled plants that form the basis of most animal production in the oceans. Zooplankton are small animals, some of which can swim actively and control their movements to some degree. They include the meroplankton, such as clam larvae, which are the planktonic stages of bottom-dwelling organisms, and holoplankton, which spend their entire life in the plankton. The predictions focus on the plankton as a balanced indigenous community, and as food for fish.

Predictions

1. The plankton studies have established that some zooplankton species are restricted close to shore (within 3-4 km), and it is probable that SONGS will reduce the local density of this group. It is probable that there will also be changes in the relative abundance of species in the zooplankton assemblage in the inner nearshore zone. The magnitude and extent of these changes cannot be predicted, and will depend on mixing rates, the ability of the populations to compensate, and on interactions between species. As an indication of the likely scale of the effects, we expect them to be somewhat less extensive than the predicted mysid effects.

2. SONGS' intakes probably will kill on the order of 10 trillion of the larger zooplankton per year, weighing about 1200 tons. Most of the zooplankton withdrawn at the intakes will enter the benthic food chain and will be lost as a direct food source for fodder fish. The fate of these diverted zooplankton is discussed in the Soft Bottom Community predictions.

We cannot yet estimate precisely the kill of plankton entrained by the diffuser plumes. If 10% of those entrained were to be killed by being moved offshore to unfavorable habitat, the annual kill would be on the order of 4000 tons. This transported plankton will be eaten largely by the same species of fodder fish that would have eaten it inshore, before SONGS began operation. We therefore do not expect to see significant changes in the overall abundance of fodder fish or sport and commercial fish as a consequence of this shift in biomass.

3. About half of the time, the diffuser discharges will bring to the surface, offshore, relatively nutrient-rich water from closer to the shore and nearer the bottom. We estimate that this will result in the annual production of an extra 84,000 tons of phytoplankton in the mid or outer nearshore waters. The fate of this extra biomass is discussed in the Fish predictions.

SOFT BOTTOM COMMUNITIES

Introduction

The soft benthos community is made up largely of invertebrates (worms, clams, crustacea, etc.) that live in and on the sand, silt and mud bottom. These bottom types cover roughly 80% of the area in the general San Onofre region. The distribution and abundance of these species is strongly influenced by the physical characteristics of the sand, silt and mud and by the amount of food material in the area. The communities close to shore (out to a depth of about 10 meters) are less diverse and less abundant than those further offshore. Most of the species are planktonic in their early stages. Although these communities are not as productive of fish, on a per area basis, as are reefs and kelp beds, because they are so extensive they help to support large populations of fodder fish and hence of sport and commercial fish species.

Predictions

1. SONGS Units 1, 2 and 3 will alter the bottom sediments. Close to the diffusers (within 1 km) the sediments will be coarsened and enriched. Beyond this area, in a pattern and at distances that we cannot yet predict, the sediments will become somewhat finer, and they will be enriched. The general result of these changes will be an increase in the abundance, number of species, and, probably, in annual production of biomass in the enriched region.

2. SONGS could have a negative influence on the soft benthos community by killing some of the organisms that live on the bottom but that occasionally rise into the water column. (This group of organisms bears a broad similarity

to mysids.) It will also reduce the number of larvae of some species available for settlement, by killing the early stages that float in the plankton. This could affect the adult density of some species, especially those living in the intertidal and shallow water zones. Among this group, lobster is a sport and commercial species. However, too little is known about the population dynamics of the early stages to hazard a prediction about possible effect on adult densities. We suspect it will not have a significant effect on the overall production of the community.

3. The enrichment of the soft benthos is not expected to influence the production of sport and commercial fish.

HARD BOTTOM COMMUNITIES

Boulders and reefs near SONGS are covered by a variety of organisms in addition to kelp. These include smaller species of algae and sedentary animals that permanently attach to the rock surfaces. Apart from their intrinsic value as part of the community, these organisms provide both a source of food for fish and important habitat structure, and they may compete for attachment surfaces with kelp.

There are distinct inshore (intake depth) and offshore (around SOK depth) communities. Turbidity is higher inshore, and inshore species are more tolerant of this higher turbidity. They also grow more rapidly than offshore species. It is thus possible that increases in turbidity in the offshore portion of SOK will lead to a change in the community such that inshore species will tend to replace the resident offshore species. Conceivably these inshore species could also slow the recruitment of kelp by outcompeting it for space.

While these possibilities exist, there is no strong evidence to suggest they will occur.

RATIONALE

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In this section on fish we do not give a separate rationale for each prediction, since the same types of analyses underlie predictions 1 and 2.

A. The affected fish species

SONGS Units 1, 2 and 3 are most likely to have a significant effect upon fish species that live as adults mainly nearshore (within about 4 km of shore), and that produce planktonic (drifting) eggs and larvae in the same zone. Most species of fish in the SONGS area are of this type. However, most individuals, and most of the total tonnage of fish are Northern anchovies. Anchovies also extend well offshore. There are several hundred billion anchovies in the California Bight, they move enormous distances, and SONGS will not significantly affect the population of this abundant species, although the Plant will kill large numbers of anchovies. They are not considered in most of the analyses below (but see Section I), which concern nearshore species only. A numerically small group of nearshore species either carry their young internally, or have planktonic larvae but lay attached, not free-floating, eggs. This group is also excluded from subsequent analyses.

We will be concerned mainly with those nearshore fish species that produce both planktonic eggs and planktonic larvae. These species fall into one of two groups. (1) Forage or fodder fish. These species eat plankton, small bottom-dwelling organisms, mysid shrimps, etc., and are themselves food for sport and commercial species. The major species in this category are queenfish (Seriphus) and white croaker (Genyonemus).

(2) Sport and commercial fish are the second group. Among nearshore species, halibut and white seabass are the main commercial species while kelp bass and sand bass, and halibut, are the main sport species. These four

species made up over three-quarters of the 1975 sport and commercial catch of nearshore fish in the fish blocks near SONGS.

B. Mechanisms

There are six known or suspected mechanisms through which SONGS can affect fish populations. These are:

(1) Killing juvenile and adult fish as they are taken into the intakes of the cooling system (via impingement and entrapment).

(2) Killing planktonic eggs and larvae that are taken into the intakes.

(3) Killing planktonic eggs and larvae that are caught up (entrained) by water jetting out of the discharge or diffuser systems.

(4) Loss of fish from special habitats (e.g. kelp).

(5) Loss of fish food that is moved by the cooling system.

(6) (Sub)lethal effects of discharged organochlorines.

We have no evidence that mechanisms (5) and (6) will operate to affect sport and commercial fish production, and they will not be discussed further in this Report.

C. Estimation of probable losses of fish

(1) Direct kill of juveniles and adults in intakes

Unit 1 kills, on average, 16.7 tons of fish per year. The fish are disposed of on land. Of these fish, 10.2 tons are fodder fish, 2.5 tons are electric rays (which are of scientific and economic importance), 2.4 tons are nearshore sport and commercial fish species, and 1.6 tons are other species.

The intake structures of Units 2 and 3 have been modified to reduce the fraction of fish taken in by the intakes. In addition, a fish-return

system has been devised to return those caught back to the ocean. This system has not been tested. The MRC fish study group feels that the fish-return system is likely to kill or fatally injure most fish that pass through it. If the new systems are 50% efficient, the total intake mortality will triple. If they are completely inefficient, total intake mortality will increase about 5-fold since all three structures provide about five times as much attractive "reef structure" as Unit 1. (The volume of water taken in by all three units will be six times that taken in by Unit 1.) If the fish-return system is not more than 50% efficient, the annual impingement fish kill will fall between 3 and 5 times that of Unit 1, or 50-84 tons, of which 7-12 tons will be near-shore sport and commercial fish. This is equivalent to 4-7 tons of nearshore sport and commercial fish production.

The losses to Unit 1 already produce measurable effects on queenfish. The population of this species within ½ km of the intake (and perhaps as far as 2 km) has fewer young fish and fewer females than more distant populations. Young and female fish are precisely the groups taken in selectively by the intakes. Two-thirds (by weight) of the fodder fish taken in are queenfish. Some 31-51 tons of fodder fish will be impinged. These fish would otherwise have contributed 25-41 tons of fodder fish production (Table 1).

(2) *Killing of planktonic fish eggs and larvae in intakes*

Most nearshore species spend 2-4 months as planktonic eggs and larvae and throughout this stage can be caught up by the intakes or diffuser water. This is the major source of mortality. It is estimated by a somewhat complex procedure involving a model of fish mortality, and we describe the methods only briefly. There are a number of steps in this procedure.

(a) The density of eggs and larvae of various ages, in water at various depths and distances offshore, is estimated from samples. (There is a tendency for older larvae to occur inshore and nearer the bottom, at diffuser and intake depths.) Next, the rate at which SONGS will withdraw water from each of these locations is estimated (from a model of SONGS hydrodynamic behavior). This gives the number of eggs and larvae that will be entrained. Finally, an assumption is made about the fraction of entrained eggs and larvae that will be killed. All of those passing through the intake are assumed to die. (Similar calculations can be made for those caught up by the diffusers, but we cannot yet estimate the fraction of those taken up that will be killed.)

These various estimates allow calculation of the expected number of eggs and larvae that will be killed per unit time (say, each day), immediately after the Plant is turned on (Fish Appendix 1).

We cannot assume this kill rate will continue indefinitely. For example, some water that has been affected by the Plant may remain in or return to the vicinity and mix with "new" water that moves into the area. When this happens, the local density of eggs and larvae will be lower than elsewhere, and fewer eggs and larvae will be killed per unit time.

A detailed model of the current regime in the SONGS area could be used to estimate the rate of replenishment of water in the area, and hence the local density of eggs and larvae exposed to SONGS. Such a model was not available when the present calculations were made.

(b) Instead, a model was used that simply assumed that SONGS will draw eggs and larvae only from some specified region along the coast. Inside this region, all eggs and larvae are assumed to be equally vulnerable (good mixing

is assumed). No egg or larva outside the region can be killed by SONGS and no eggs or larvae can leave the region. The model has the following features (Fish Appendix 1):

- Eggs are produced in this region at a constant annual rate that is the same as elsewhere. (This is essentially the conservative assumption that, even if SONGS kills many plankters and subsequently lowers adult density in the region, reproductive fish will move in from elsewhere.)

- The model calculates the chance that an egg or larva of a given age, within the region, is killed by SONGS before it reaches the next age class (which is 2.5 days older). This is done for all age classes up to the point when the larva becomes a juvenile (4 months in queenfish, for example). Since eggs and larvae die off extremely rapidly due to natural causes, most of them are not killed by SONGS but die of natural causes. This natural death rate is taken into account by the model.

- The chance of any individual being killed by SONGS before it moves out of its age class depends on the size of the region chosen (the chance is smaller when the region is bigger because within 2.5 days a smaller fraction of the water in the region passes through SONGS). Clearly, if a very small region is chosen, a given individual can be exposed to risk on different occasions since the same parcel of water passes through SONGS many times. In this case, the density is rapidly depleted, the fraction killed is high, and most larvae do not grow very old. On the other hand, the number killed is somewhat smaller.

- Since the natural mortality rate is high, there are always far fewer older larvae than younger larvae and eggs. This is reflected in the predicted

SONGS kill. For example, under one set of assumptions, SONGS will kill in a year 16 billion eggs and 4 billion larvae of nearshore fish.

Clearly the choice of the size of the "affected region" is somewhat arbitrary. Choosing a very small region (say 1 km) is equivalent to assuming virtually no currents along the shore, and hardly any replenishment of the waters around SONGS by "new" water. This will overestimate the degree of local suppression, but will underestimate the number killed - larvae from elsewhere that in reality would get to SONGS are not counted. On the other hand, choosing a very large region (say several hundred kilometers long) is equivalent to assuming that fish eggs and larvae move huge distances in their lifetimes. This would maximize the number killed, but (especially since thorough mixing is assumed) it would spread the effect out very thinly. We feel that this latter scenario is closer to the real situation. 50 km was chosen as a compromise between smaller regions within which complete mixing can be assumed, and larger regions within which all doomed fish larvae are certain to have been produced. SONGS <u>will</u> kill billions of eggs and larvae, and the degree of movement of eggs and larvae will determine whether there is a pronounced local depression or a less obvious, but much more extensive, depression. If there is no re-entrainment of "old" water by SONGS, a choice of 50 km will underestimate the number of eggs and larvae killed.

The result of the model's calculations is a predicted number of eggs and larvae killed per year (breeding season) in each age class.

(c) These predicted losses of eggs and larvae are then converted into an equivalent number of 13 month old fish (Fish Appendix 1). (An age of 13

months is chosen primarily because this corresponds in size to that of the average fodder fish eaten by sport and commercial fish.) The idea involved in calculating 13 month old equivalents is as follows: an egg has roughly 1 chance in a million, under natural conditions, of becoming a 13 month old adult. Therefore, if SONGS kills an egg, this is equivalent to killing only one-millionth of a 13 month old fish, because in all likelihood the egg would have died anyway. However, if SONGS kills a 4 month old larva it has killed the equivalent of .4 of a 13 month old adult, because a 4 month old larva under natural conditions has a 40% chance of becoming a 13 month old adult. It is predicted that SONGS will kill the equivalent of several million 13 month old adults of nearshore fish species.

At the moment, age distributions of larvae are available for only the two major fodder fish species. To estimate losses of sport and commercial species we have therefore assumed that, averaged over the season, the sport and commercial species have the same age distribution as these two fodder fish species. The estimates of sport and commercial losses owing to larval mortality therefore are based on this, as yet untested, assumption.

(3) Diffuser losses

(a) Turbulent shear losses

There is evidence from the literature that fish larvae die when they are subjected to shear forces on the order of several hundred dynes/cm^2 over a period of several minutes. Losses due to this mechanism were estimated in two steps (Fish Appendix 1). First, the fraction of secondarily entrained water that is likely to be subjected to shear forces on the order of 100/cm^2, or greater, was calculated. Second, the number of larvae subjected to this

stress was estimated from known larval densities and from the estimated amount of water entrained. These calculations suggest that only a relatively small number of larvae will be killed in this way.

(b) Translocation losses

Nearshore fodder fish larvae show a very clear pattern, in which density falls off very rapidly several kilometers from shore. The pattern suggests that larvae that are carried farther offshore die. During some parts of the year, SONGS' diffuser plumes are expected to move some inshore water to an area 5 km or more offshore.

The larvae of sport and commercial fish species extend from close to shore to about 7 km offshore. We therefore do not expect SONGS to cause translocation mortality in this group.

At some times of the year, especially when they are older and "more valuable", the larvae of both queenfish and white croakers do not extend beyond 2 km from the shore. We therefore expect large translocation losses of fodder fish larvae, but we are not able to make a quantitative prediction. Some idea of the possible magnitude of these losses can be gained by noting that if 10% of larvae entrained by the diffuser plumes were to be killed, total fodder fish losses would roughly double.

(4) Losses from damage to kelp bed

Damage to the kelp bed and its biota may be anything from negligible to extreme (see Kelp Predictions).

D. Conversion of losses to biomass (weight of standing stock of fish)

The losses of 13 month old "adult-equivalents" were divided between sport and commercial fish and fodder fish according to the frequencies of these two

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types in the larvae affected. Among nearshore planktonic spawning species, in general, four-fifths of the larvae are fodder fish and the remaining one-fifth are sport and commercial fish. However, their relative frequencies vary with proximity to the shore and with position in the water column, and these differences were taken into account.

Next, numbers lost were converted to a weight (biomass) for each group (sport and commercial fish live longer than fodder fish and are larger, so the converaions are different) (Fish Appendix 1). The idea here is that, once SONGS has been operating for several years, 1, 2, 3, . . . year old fish are all affected and each year there will be an average loss of fish weight, spread over all ages, in each species.

E. Conversion of losses to annual production

Each year, each fish population produces a certain tonnage of "new" biomass, through reproduction and growth. In a perfectly balanced fishery, each year this same amount of tonnage would be consumed - by natural deaths plus the fish harvest. The annual production of a typical sport and commercial population is reckoned to be about 60% of the standing stock (biomass). Thus, when the equivalent of 100 tons of sport and commercial biomass is lost as larvae and eggs, this is equivalent to a loss in production of 60 tons. Similar calculations are possible for fodder fish, where the figure is thought to be 80%.

F. Conversion of fodder fish losses to sport and commercial losses

Sport and commercial fish depend predominantly on fodder fish and, since the biomass of the latter is expected to be reduced, there should be less food for sport and commercial fish. It is difficult to know how to estimate the

effects on sport and commercial species of this predicted loss of fodder fish production. A standard rule of thumb is to assume that 10 pounds of fodder fish production yields one pound of sport and commercial production - a 10% "transfer efficiency". However, if sport and commercial fish population are being held at relatively low densities, say by fishing (Section G), then changes in food supply may have little or no effect on their production. In addition, the fodder fish losses may be partly or largely compensated for (see next section). These considerations suggest that 10% is too high a figure. We think it unlikely that sport and commercial fish production is totally unrelated to fodder fish production, and so assume a 1% relationship as a lower (and more likely) bound.

G. Compensation and declines in nearshore fish species

It is possible that reductions in larval fish density caused by SONGS would lead to higher survival of the remaining fish larvae (for example, by making more food available to each larva). There is, at the moment, no good evidence for such compensation in marine larval fish, and there are a priori reasons for suspecting such compensation would at best be weak. First, fish larvae are already very sparse. Second, it is likely that "chance" (density independent) factors dominate the mortality of these small organisms. Third, much of their food will be killed along with the larvae themselves.

Another possibility is that juvenile or adult fish might survive, grow, or reproduce better in response to lowered density of juveniles. We think this is possible for fodder fish because there is no evidence that their numbers have been declining. However, we think it unlikely that compensation in nearshore sport and commercial fish would be adequate in the face of significant

extra mortality. The main reason for this view is that these species appear to have declined in Southern California since the mid-60s (Fish Appendix 1).

The evidence for declines in nearshore sport and commercial fish species is by no means unequivocal. We have to rely on indirect measures of fish stocks. The major evidence is from California Department of Fish and Game records of sport and commercial catches. These suggest strongly that halibut, in particular, has declined, that kelp bass and sand bass may have declined, and that the more desirable nearshore sport and commercial species as a group have declined.

Several arguments can be made against these conclusions. Counter-evidence, together with comments, is as follows:

(1) Populations fluctuate naturally, and these species showed strong declines in the 1950s, followed by a recovery.

Populations do fluctuate. But this is not evidence that current declines are "natural" and can be ignored. The declines in the 1950s, for example, may have been caused by loss of kelp bed habitat, and DDT in the Bight, and these two mechanisms are now diminished.

(2) Catches of fish in power plants do not show clear evidence of declines.

However, the data from impingement by power plants suffer several defects. First, such data are highly influenced by catchability of fish (which is influenced by annual variations in the weather), as well as by their density. They usually are available for only a few years in the 1970s, and such variations in catchability could easily obscure real trends. Second, the data are extremely variable, and this could obscure trends over this short period.

Third, the data are for only the 1970s, often not for the whole decade, and the Fish and Game data show that the decline was most precipitous in the mid to late 60s and has been rather slight in the 1970s. (The Fish and Game data are much less variable than the Power Plant data, especially in the 1970s.) Thus, we would not even necessarily expect to see a decline in these Power Plant data.

On balance, we believe the data support the conclusion of a decline in desirable nearshore sport and commercial fish.

H. On-shore off-shore water movements

The predictions have not taken into account the possibility of large scale onshore and offshore movements of water. (MRC is now measuring this phenomenon.) Such movements could create "circulation cells" that would slow down the longshore movement of eggs and larvae (although it is possible that, by choosing water layers, larvae could escape from such cells). This would reduce the estimated loss of larvae, but would create a more detectable local depression in larval density around SONGS.

I. Upwelling caused by SONGS

Some of the water entrained by SONGS' diffusers will come from below 7 m depth. Water at this depth in the region of the diffusers is rich in nutrients, but has low light levels, so that it produces little phytoplankton. The diffuser plume will generally move this (and other inshore water) closer to the surface, where there is more light, and farther offshore. This will result in an absolute increase in phytoplankton production in this region.

We estimate (Fish Appendix 2) that, each year, some 84,000 tons of additional phytoplankton will be produced. Most of this will be eaten by

zooplankton. Although it is not possible to say exactly how this production will pass up the food chain, a reasonable estimate is that half of the phytoplankton will be eaten by microzooplankton, then by macrozooplankton, and then fodder fish. The other half of the phytoplankton will be eaten by macrozooplankton, and then by fodder fish. In this region (roughly 3½ km offshore) the major fodder fish is the anchovy, and most of the new production should pass to this species. A transfer efficiency of 10% would produce, in tons of fodder fish:

$$[4.2 \times 10^4 \times 10^{-2}] + [4.2 \times 10^4 \times 10^{-3}] = 460 \text{ tons.}$$

During these transitions the new production (as phytoplankton and zooplankton) will be moved away from the area of production and thoroughly mixed. The anchovy population is also extremely mobile and well mixed, so this production of anchovies would be expected to be spread over a very large fraction of the Bight population.

460 tons is a miniscule fraction of yearly California anchovy production, which is about 1-2 million tons. We believe it would not result in any real increase in yield to sport and commercial fish. It should be remembered that we have made a similar argument for ignoring anchovy losses: each year, SONGS will kill on the order of 10 times as many anchovy larvae as other fodder fish larvae, and the fodder fish losses themselves are equivalent to more than 300 tons of production, but we predict no effect from these losses. Clearly, in "production equivalents", the anchovy losses are much greater than 300 tons, but we believe it is sensible to assume that perturbations of this order, spread over the whole anchovy population, will have no effect on adult anchovy standing stock, and hence production.

As discussed in Section F, the transfer efficiency from fodder fish to sport and commercial fish probably lies somewhere between 1% and 10%, and we have argued it is likely to be close to 1%. If the increase in anchovy production were to be passed on, we would expect it to produce an extra 5-46 tons of sport and commercial fish, and believe the lower figure much more likely. Most of this production would not be in nearshore sport and commercial fish, since the mass of the anchovy population is offshore.

KELP CONTENTS

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I. Biology of Kelp

We begin by looking at the basic population dynamics of the San Onofre kelp bed.

(A) "Normal" conditions

It appears that, even in the absence of catastrophic events, the kelp bed is rarely in a "steady-state" or equilibrium condition. It is instead dominated by physical and oceanographic conditions that are highly variable. In the present study (1976 to 1980), only by the end of 1979 did SOK cover most of the cobble substrate available. Naturally,the amount of kelp (number of plants and areal extent) on any section of the bed fluctuates in response to changes in bottom conditions, storms that tear adult plants from their sites of attachment, water temperature, availability of light and nutrients, grazing by sea urchins and probably fish, fouling, and periodic recruitment. Patches of kelp within the bed increase and decrease and even disappear and reappear under normal conditions.

Recruitment of new plants is a major dynamic event that is episodic, in response to seasonal and annual variation in physical and chemical conditions. It appears that recruitment occurs, on average, only once every three years. (However, recruitment rate has been examined, in this and other studies, for a total of only 12 years or so.) Although kelp has a complex life cycle (Figure 1), for present purposes there are only two important processes affecting recruitment of adults: (i) the ability of the tiny male and female stages (gametophytes) to reproduce and hence produce the microscopic first stage of the actual kelp plant (sporophyte); (ii) the ability of juvenile plants to grow up into adult kelp plants. Experiments have shown that light

is an essential factor (but not the only factor) controlling these two processes.

We need to look briefly at the dynamics of the life cycle.

(1) Reproduction, and recruitment of juvenile plants

The adult plants produce minute propagules (zoospores) that settle on the bottom and become either tiny male or female stages called gametophytes. Each adult plant produces extremely large numbers of these propagules, perhaps continually throughout the year. Thus it is probable that there are gametophytes present, most of the time, in abundance, on suitable areas of the bottom close to adult plants. The critical factor is the occurrence of a combination of suitable physical conditions (including, at least, adequate light and nutrients) that allow gametophytes to reproduce. The gametophytes that do reproduce, produce microscopically small kelp plants. This type of life cycle is known as alternation of generations. In kelp the microscopic gametophytes are the sexual stage. The sporophyte (the actual kelp plant) is the asexual stage. It is also microscopically small to begin with, but passes through juvenile and subadult stages to become the massive adult kelp plant.

Gametophytes are killed by a variety of factors - abrasion, burial by sediments, and grazing by animals - and only a small fraction of them survive to produce sporophytes (Kelp Appendix 1, p. 150). Even so, after a successful reproductive "set", there are thousands of tiny sporophytes per square meter of cobble substrate. Unfortunately, it is extremely difficult to study these microscopically small plants in natural conditions. Quantitative studies have been done only on larger plants that have reached a height of

more than 10 cm (4 inches). At about 40 cm (16 inches) the plant becomes a juvenile (Figure 1). Once again, a variety of factors kill most of the sporophytes before they become juvenile plants.

It appears that the physical environment affects these processes in the following way. Reproduction by gametophytes requires adequate light and, probably, a high concentration of nutrients in the bottom water. When these conditions prevail, the gametophytes absorb sunlight and nutrients each day, until they mature to a reproductive condition. Field experiments show that very few sporophytes ever appear from gametophytes planted out more than 40 days. Thus, in the field, 40 days apparently is the maximum period during which this stage can accumulate the sunlight needed for survival and reproduction. Over this period they need an average of at least .43 Einsteins per m^2 per day (Kelp Appendix 2, p. 5). (Under good field conditions it is likely that the average successful gametophyte manages to accumulate enough light in about 20 days.) The critical question for sporophyte recruitment, in any given year, is therefore: during the period in which gametophytes are present, what is the probability (a) that enough light can be accumulated during at least one 40-day period (called a "light window"), and (b) that nutrients are also adequate during the light window?

It appears that these two conditions co-occur only rarely. (a) The frequency of light windows varies with the situation. In a very sparse part of the kelp bed, where adults were absent and vegetation had been cleared, all of the spring season consisted of light windows (Kelp Appendix 3, Table 1, p. 5). However, in darker portions of the bed, where adults are present in abundance, none of the 40-day periods appeared to have received adequate light

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on the bottom. With a light understory of other algae, and heavy adult canopy, about 30% of 40-day periods were light windows on the bottom.

(b) It appears likely that nutrients are adequate only during periods of upwelling. In any given spring these periods last for only a few days, and occur not more than a few times per season (Kelp Appendix 1, Figure E1, p. 260).

Suitable conditions for reproduction occur mainly in the spring, although occasionally also in the fall. It appears that adequate conditions for reproduction occur, on average, only once every three years (Kelp Appendix 2). At any one time the bed is thus generally dominated by a "cohort" of adult plants from a single episode of reproduction.

As discussed below, SONGS is predicted to decrease the frequency at which conditions become suitable for reproduction. We cannot predict whether or not SONGS will affect the number of sporophytes or juvenile plants that arise from any given successful reproductive set. It is likely, however, that some factors will not have much effect on the number produced:

(a) Each adult plant produces enormous numbers of gametophytes. Thus, unless the density of adult plants is catastrophically reduced, we assume that there will be enough gametophytes present to replenish the bed even when adult density is low. (This is equivalent to assuming there is density "compensation" in the survival of these small stages.) There must be some very low density of adult plants at which replenishment through a single reproductive set is not possible, but we make the conservative assumption that it is very low, lower than is encountered during "normal" conditions.

(b) With respect to light levels, reproduction is all-or-nothing. When adequate light is available, the number of tiny new plants (sporophytes) produced is independent of the light level. The number produced appears, instead, to be associated with the amount of nitrogen in the bottom waters, and this is not expected to be affected by SONGS.

The survival of sporophytes to the juvenile stage is determined by a range of factors (abrasion, sedimentation, grazing).

(2) Survival from juvenile to adult stage

Juveniles frequently suffer a higher death rate than adults (Kelp Appendix 1, pp. 93 and 95), so anything that prolongs the juvenile stage will reduce both the eventual number of adults and the average density of kelp plants. Light affects the growth rate, and so does fouling. These factors are discussed later.

The growth rate of juvenile kelp plants is highly variable. Some plants in a group develop from juvenile to adult in less than three months, while others take more than 13 months. The survivorship from juvenile to adult stage is also highly variable, and depends on, among other factors, both the initial number of juveniles and the number of adults present. The fraction surviving tends to be higher when (a) fewer juveniles are present initially (Kelp Appendix 1, p. 82), and (b) fewer adults are present (Kelp Appendix 1, p. 84, and Kelp Appendix 2, p. 10). These relationships reflect an important result: except when very low densities of juveniles are present, the final number of adults present is roughly constant. (This means there is strong "compensation" or "density-dependence". If some factor reduces juvenile density, the number of adults produced may be relatively unaffected.)

(3) Summary of "normal" kelp population dynamics

A final piece of information completes the picture of "normal" kelp bed population dynamics, namely that the average adult plant survives for about 12 months (Kelp Appendix 2, p. 11). That is, if we start out at some point in time with a cohort of adults produced by a successful reproductive "set" a year or more earlier, we can expect roughly half to die within 12 months. By the end of two years roughly 25% of these adults will remain alive, and by the end of three years, roughly 12½% will remain alive. At this time, on average, we could expect another cohort of adults to appear. In reality, of course, the dynamics would not follow this average pattern, but would vary around it. For example, deaths occur mainly in winter storms, which vary in their severity from year to year; again, reproductive sets will sometimes be spaced one or two years apart, and sometimes four or five years apart.

The number of kelp plants in the bed thus fluctuates, rising rapidly after a successful recruitment event, and declining thereafter. However, the canopy area of the bed will not clearly follow this pattern since the surviving plants will continue to grow. The canopy area can thus increase even though the number of plants may be decreasing.

(B) Catastrophes

We know little about the frequency of catastrophes in the SONGS area before the 1950s. Certainly the kelp beds in the general area were more extensive and continuous when they were observed at various times earlier in the century than they have been since (Kelp Appendix 1, p. 12). It is likely that much of the cobble in this area has been covered by sediments since then. We do not know, however, if the beds were severely reduced between the infrequent

observations made before 1950.

Two catastrophic die-offs have occurred since 1956 (Kelp Appendix 1, p. 12). The first, in 1958-59, was associated with high summer temperatures (but may have been caused by associated low levels of nutrients). At this time 90% of Southern California kelp beds were destroyed. SOK was not re-established for a period of 12 years (by 1972). In 1976, again a year of unusually high temperatures, SOK suffered a partial die-off, being reduced to less than 10% of its former extent, and only in the offshore segment did plants remain. Recruitment occurred about a year later, and recovery of the canopy took almost two more years.

There are two means by which kelp disperses and, hence, beds recover or become re-established. First, the adult plant casts its microscopic offspring varying distances. Many offspring probably fall very close (a few meters) to the plant. (Observations at SOK show that some offspring may be dispersed one or two hundred meters from the bed, but we do not know if these were offspring from plants attached in the bed, or from plants that became detached and drifted from the bed.) Secondly, adult plants, torn loose in storms, drift and sometimes cast spores on suitable substrate far from their point of origin. Re-establishment of a bed therefore depends on chance events, and seems more likely when a source of "colonists" is close by. This is one reason why the longshore continuity of beds is important. Recovery of a kelp bed that has been drastically reduced, but not exterminated, depends mainly on local reproduction. Observations at SOK, in the very successful reproductive season of 1978, suggest that a large "set" of new plants can arise from quite a sparse kelp bed, and that recovery can be rapid if the catastrophic

die-off is followed quickly by successful recruitment. By contrast, the 1958 catastrophe suggests that major catastrophes can be followed by very long recovery periods because no or extremely few plants survive locally.

II. Estimating the Effects of SONGS Units 2 and 3

(A) Predicted effects on kelp reproduction

The two major factors affecting reproduction are light and nutrients. Increased turbidity caused by SONGS' discharge will reduce the light in SOK during spring, the main reproductive season. The probable effects on reproduction were estimated by first calculating the expected reduction in light and, second, by calculating how this should affect reproduction. SONGS is not expected to alter nutrients on the bottom, where reproduction occurs.

The probable levels of light that will prevail in the kelp bed once Units 2 and 3 are operating were calculated in four steps (Kelp Appendix 1, pp. 222-241, and Turbidity Appendix). First, ambient light levels near the bottom were recorded. Second, a computer simulation model of water movements near SONGS, including those caused by SONGS' intake and diffuser systems, was developed. This was based on information obtained from current meters placed in the ocean near SONGS, and from a physical model of SONGS-induced water movements produced for Southern California Edison. Third, measurements of natural turbidity levels were made in spring and summer. This information allowed prediction of expected levels of turbidity in the kelp bed for these two seasons. Finally, measurements of light and turbidity levels in the field yielded a strong quantitative relationship between light and turbidity. The calculations predict (conservatively) that in spring, in the (most important) offshore half of the bed, subsurface light levels on average will be reduced

by from 25% to 55%, with a roughly 40% reduction being most likely. No significant reduction in light is expected in the already turbid inshore segment. The offshore half of the bed has been the most persistent during catastrophe, has the densest canopy cover, and constitutes 70% of the total SOK canopy cover. Subsurface light will be much less affected in late summer.

A 40% reduction in subsurface light will reduce the number of 40-day light windows, and hence the probability of recruitment. The amount of reduction depends on the prevailing light regime. In a clear part of the bed, where all 40-day periods are suitable, a 40% reduction in light would cut the number of light windows by 20-30%. At other parts of the bed, where light windows are already scarce, the reduction could be close to 100%. We will use a 20% reduction as a conservative estimate, since the most critical recruitment events occur when the bed is sparse and therefore ambient light levels will be high.

To estimate the potential effect of this reduction in underwater illumination on reproduction, a model of reproduction is useful. A crude model, assuming that <u>only one</u> coincidence of adequate light and nutrients is needed to provide successful recruitment in a season, is as follows. In a season of D days, there is, each day, probability w that the day is the first of a light window, probability n that nutrients are adequate, and probability g that there is an adequate supply of gametophytes. The probability that a given day will initiate successful recruitment is then wgn. If 40-day periods can be treated independently, then the probability that at least one day in the season will initiate recruitment is $1-(1-wgn)^D$ (Kelp Appendix 4).

This model can be used to estimate how a reduction in the number of light windows will affect recruitment. Suppose we reduce the number of light windows to a fraction (p) of their original number (in the case of a 20% reduction, $p = .8$). The probability a given day will begin a light window then becomes pw, and our model is $1-(1-pwgn)^D$. We assume that only when SOK is destroyed is $g < 1$, so except when the bed is absent, the model becomes $1-(1-pwn)^D$.

If wgn, or wn, is small, $(1-pwgn)^D \approx 1-Dpwgn$, and the reduction in the probability of successful recruitment will be by a factor close to p. Otherwise the reduction will be less than p. There are three cases: normal SOK population dynamics, SOK absent (when it is destroyed), and SOK reduced (when it is at very low densities).

In normal times there is very little light in the bed and w is small. Furthermore, those partially shaded areas that do provide some windows suffer a greater than 20% reduction in windows. Thus a 20% reduction seems to be a conservative estimate. Note, with $p = .8$, the average time between recruitment events increases by a factor of $1/p = 1.25$. That is, the average time between recruitment events would be expected to increase from about three years to almost four years.

In the absent phase, g is very small, since recruitment depends on the rare event of a drifting kelp plant dropping spores on suitable substrate. Thus a 25% increase in the time to recruitment is a reasonable estimate. Even in the reduced phase, when w is intermediate and $g \approx 1$, n is likely to be very small and the time between recruitment events should increase by 25%.

Overall, therefore, it is reasonable to predict a 20% reduction in the probability of successful recruitment, and therefore a 25% increase in the average time between recruitment events.

(B) Predicted effects on kelp growth and survival

Light and fouling of kelp plants are the major factors that are expected to affect kelp growth. We discussed expected changes in light, above. Here we first describe fouling and then discuss the relationships among light, fouling, and growth and survival of kelp.

Fouling: Several species of small invertebrates settle and attach to kelp plants. Some build tubes from particles in the water, others merely live on the kelp blades. Under normal conditions in SOK, fouling of juvenile kelp plants is rather light, although the fouling organisms are present.

Several experimental studies show that the abundance of these fouling organisms on kelp plants and other surfaces is greater the closer they are to the discharge plume of Unit 1. This increase is caused by (probably several) factors associated with the plume, including increased particles in the water, and increased turbulence which stimulates the planktonic stages of some organisms to settle. It is also associated with lower light levels, but is probably not caused directly by reduced light.

There is evidence (Kelp Appendices 2 and 5) that increased fouling can reduce the growth of kelp plants, and damages them by causing them to lose blades, causing fronds to sink, and attracting fish and other predators.

The relationships between light, fouling and growth were examined in an experiment in which juvenile kelp plants were transplanted to the Unit 1 plume and to other areas in which underwater light levels varied (Kelp Appen-

dix 1, pp. 101-121; Kelp Appendix 2, Table 11; Kelp Appendix 3, p. 6). A multiple regression of growth rate (Δ log length in cm/day), versus irradiance ($E/m^2/d$) and percent cover by Membranipora (a bryozoan that is a major fouling organism), explained 99% of the variance in growth in the experimental juvenile plants at four locations at different distances from the SONGS Unit 1 discharge.

This experiment suggests very strongly that decreases in light and increases in fouling will have a detrimental effect on kelp growth. Unfortunately, the relationships among the three factors (light, fouling and growth) are complex, and this complexity prevents us from making a confident quantitative prediction. The uncertainty arises because (1) the effects of light and fouling on growth are confounded, (2) the relationship between growth and light is different inshore and at SOK, (3) growth and light do not always show a consistent relationship, and (4) we cannot predict quantitatively how fouling will change at SOK.

(1) Lower light was always associated with greater fouling in this experiment, and so we cannot tell how much of the reduction in growth was caused by each of these factors. Fouling alone explained 95.3% of the variance in growth, and light explained 99.5% of the remaining variance, a significant fraction, so we know light has some effect. Light alone explains 99.7% of the variance in growth, and fouling explains 93.1% of the remaining variance (which is not a statistically significant fraction). We have, so far, been unable to separate the effects of these two factors upon growth.

(2) The relation between kelp growth and light in SOK is different from the experimental relationship established inshore. At a given light level

kelp grows faster in SOK than it does inshore.

(3) There is one pair of observations in SOK that shows kelp growing at similar rates at different light levels (Annual Report, p. 110, Table 4.2).

(4) Fouling appears to be increased by an increasing concentration of particles in the water, and by turbulence. We do not know the quantitative relationships involved, and we do not have a precise prediction for these two variables under SONGS' operation. Furthermore, the organisms may 1) behave differently, 2) be a different mix of species, and 3) differ in abundance at SOK and inshore. Thus, we cannot predict the extent of fouling at SOK once SONGS Units 2 and 3 begin operation.

Experiments now underway should help resolve the relationship between light and growth.

In spite of difficulties of interpretation, however, the transplant experiment predicts that kelp growth will be reduced when SONGS 2 and 3 are operating. Reduced growth would be expected to (a) reduce the average size of plants, and so reduce kelp biomass and cover, and (b) reduce the number of kelp plants. We next explore question (b).

Reduced growth should reduce plant density because death rates of juvenile and sub-adult stages are generally higher than those for adults, and plants would spend longer in the high death rate phases. According to one set of calculations, this would lead to a 70% reduction in the number of plants produced from a cohort of new juveniles (Kelp Appendix 2, pp. 13-17). If compensation operation, the reduction could be as small as 25%.

We cannot place much reliance on these particular figures because different sets of plausible assumptions and relationships give us different

estimates that range from a negligible effect to an even greater than 70% reduction in abundance (Kelp Appendix 5). Furthermore, we still have the problems of the confounding effects of fouling, and one pair of observations of similar growth at different light levels in SOK.

No firm quantitative prediction can be made about growth and survivorship.

(C) Other factors associated with SONGS

(1) Sedimentation

Sedimentation appears to reduce the recruitment of new plants by smothering them and increasing abrasion. However, SONGS is expected to have no effect on the sedimentation rate on the bottom at SOK.

(2) Sea urchins

Sea urchins (Lytechinus) have caused a large amount (about 45%) of adult mortality in parts of the bed. They also appear to interfere with recruitment by grazing on the microscopic and very small stages of kelp.

SONGS will probably increase the amount of particulate organic matter (POC) at SOK. Schroeter et al. (Kelp Appendix 5) show that urchins grow more inshore than offshore, and argue that this was caused by higher POC levels there. They conjecture that SONGS will therefore increase urchin populations, and hence grazing pressure, in SOK. This seems a reasonable prediction, but we cannot be certain it will occur because other factors (predation, etc.) also affect the abundance of sea urchins.

(3) Toxins

Reduced growth and settlement of various organisms in the Unit 1 discharge plume have led investigators to postulate that the plume contains

small quantities of toxin(s) - perhaps copper or chlorine. Southern California Edison claims that Unit 1 releases extremely small amounts of copper, that copper will be virtually absent from the plumes of Units 2 and 3, and that these units will also use little chlorine.

There are no usable data on toxins from SONGS, and we cannot evaluate their possible role. This point requires investigation.

(4) Temperature

SONGS is expected to have very little effect on water temperatures in SOK (a less than 0.5°C average increase, a maximum of a 1°C increase, and a non-detectable increase over most of the bed).

(5) Nutrients

The concentration of nutrients is expected to increase in SOK in surface and mid waters at some periods of the year. We have no quantitative prediction of this effect, nor do we know the relationship between nutrient levels and adult plant growth. This mechanism could lead to greater plant growth (Plankton Appendix 2).

(D) Overall effects on the kelp bed

The predicted reduction of recruitment, and an increase in mortality, would lead to a reduced density of kelp plants in the offshore portion of the bed. These two effects plus reduced growth of individual plants and greater grazing by urchins would reduce the amount (biomass and cover) of kelp in the bed. Increased midwater nutrients could cause an increase in kelp growth. We cannot make a quantitative estimate of the overall effects.

(E) Effects on shrimp in the kelp canopy

Experiments carried out at various distances from Unit 1 discharge

showed that shrimp densities on settling plates were lower close to the discharge. These spatial differences tended to disappear when SONGS was not operating. It was also shown that the death rate of shrimp in experimental containers was greater closer to the Plant.

The mechanism causing these effects is not known, so no quantitative predictions of the effects of Units 2 and 3 can be made.

Shrimp are important in the diets of various fish species that live in SOK (Kelp Appendix 5, pp. 12-13).

MYSIDS

1. Annual loss of mysids

From the field sampling program we know how mysid densities change as one goes offshore. Several species, constituting most of the mysid population, are restricted to within 3 or 4 km of the shore (Mysid Appendix 1). Maximum mysid density occurs in the intake zone.

These data, plus information on the rate of SONGS' intake of water, allow us to calculate how many mysids will be taken into SONGS' intakes. Sampling at Unit 1, and laboratory studies, suggest that all mysids taken into the cooling system will be killed.

We are much less certain of the number that will be killed by the discharge plume, which will entrain about 10 times its own volume of water. There are two possible sources of mortality. First, some mysids will die from turbulent shear forces created by the discharging water. We believe this will be a relatively minor source of mortality. Second, some mysids will be carried further offshore in the plume and deposited offshore of their normal habitat. There is as yet no reliable method for predicting the number of mysids dying in this way.

2. Mysid depression

(a) Depression caused by intake and diffuser mortality

If mysid mortality is of the order calculated in Section 1, we would expect there to be a lowering of mysid density downstream from the Plant. The extent and depth of the depression depends upon the rate of mixing with water that has not passed through the Plant, and on the ability of surviving mysids to compensate with increased reproduction, growth or survival.

The probable extent of the depression was estimated using a model that combines a description of water movements and the biology of the mysids (Mysid Appendix 4). The model describes both the ambient current regime and SONGS' plume, and moves mysids about accordingly. It incorporates the natural mortality rate of mysids (as determined from samples) and imposes on this rate the expected SONGS-induced mortality. The model incorporates 100% intake mortality and 20% mortality in the plume. (The model assumed that this was caused by turbulent shear. It is more likely that any diffuser losses will be caused by translocation; however, we use the output as an indication of the scale of possible effects.)

The model predicts that, for much of the year, depressions on the order of 50% should exist out to 5 km or more from the Plant, and that lesser depressions should extend for more than 10 km.

We need to view these predictions with caution. The model is not a precise description of reality; in particular, it becomes less accurate as it predicts events more distant from the Plant. Also, the amount of translocation mortality is not known. What the model does tell us is that we can expect to see a measurable depression in mysid density, at least several km long, for much of the year, and it probably indicates the maximum size of the depression that could be caused by these mechanisms.

(b) Depression caused by an unknown factor

The Mysid Study group has data suggesting that Unit 1 presently causes a depression in mysid density of almost 50% that extends 6 km downstream (Mysid Appendix 3). This is the difference observed in the longshore pattern of abundance between samples taken when the Plant is on, and when it is off.

There is statistical support for this claim, but there is a difficulty in that the "Plant on" samples were taken in October, while the "Plant off" samples were taken in spring, and the general level of mysid abundance was greatly different at these two seasons. Samples are being taken now, while the Plant is off, to resolve this issue.

The Committee feels there is a further problem with these results. Even if it can be shown statistically that a depression occurs when the Plant is on, but not when it is off, we know of no mechanism that is likely to produce such an effect. (The actual kill via intake and plume mortality would not depress the population for such a distance, and the plume from Unit 1 rarely extends more than 3 km from the Plant.) One suggested mechanism is that organochlorine compounds from the Plant adhere to very small particles and settle out over a distance of 6 km. We have no evidence concerning this mechanism. If the new studies confirm the existence of this depression, further work will be required on this question.

If indeed there is a depression to 6 km caused by Unit 1, then it may be reasonable to expect that the enormous additional kill rate of Units 2 and 3 will extend the depression to 10 km or so. Notice, however, that there is no evidence that the plume from Units 2 and 3 will extend further downcoast than that from Unit 1. Thus there is no certainty that the additional intake and plume losses from Units 2 and 3 would extend an already existing depression.

3. Significance of mysid losses

Mysid populations are extensive along the coast, and our predictions do not imply that SONGS would have a significant effect on the coastal populations. As stated in the "Predictions", we do not expect these effects to have a major

impact on the local populations of fodder fish, although this is certainly a prediction that we need to check when Units 2 and 3 begin operating.

PLANKTON

1. The evidence that some zooplanktonic species are restricted close to shore can be found in Plankton Appendix 1. The centers of abundance of the inner nearshore species are in the areas of the intake and diffusers, and these species are therefore subject to greater SONGS pressures than other less restricted species. Some of the zooplankton restricted to the inner nearshore tend to live closer to the bottom where the longshore currents are slower (MRC Interim Report 1979-02 (II), p. 17), and as a consequence their longshore replacement (mixing) rates could be lower than those for other species. In addition, some of the non-restricted species could be replaced by individuals from farther offshore. All of this would favor the non-restricted species in the recovery from SONGS losses and would tend to promote a shift in relative abundance.

2. Synoptic samples taken in the intake and discharge ports of SONGS Unit 1 demonstrate that few of the withdrawn zooplankton occur in the discharged waters (MRC Interim Report 1979, and Plankton Appendix 2). Presumably, they are consumed during their journey through the intake conduit by the benthic organisms that live on the inner walls. These benthic organisms are purged from the cooling system during heat treatment and reverse flow, and become part of the inshore benthic food chain. The estimates of plankton densities used in predicting intake losses can be found in Plankton Appendix 2.

The estimate of zooplankton entrainment by diffusers is based on total macrozooplankton (zooplankton greater than .2 mm in width) plus the microzooplanktonic species Euterpina acutifrons. Euterpina was included because

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it forms a major part of the diets of most fish larvae and some fodder fish in the area. Using the field samples from 20 dates for macrozooplankton and from 5 dates for Euterpina, the mean concentrations were calculated for different positions expected to be affected by diffuser entrainment (Plankton Appendix 2). This estimate of about 4×10^4 metric tons of zooplankton entrained per year was based on the assumption that equal entrainment occurred at all depths over the full length of the diffusers. The assumption that 10% of those entrained are killed results in an estimate of 4000 metric tons.

Most of the zooplankton biomass moved offshore by diffuser entrainment is likely to be eaten by adult and juvenile anchovies, top smelt, and blacksmiths. According to the MRC Fish Group, the blacksmith should increase in abundance because the diffuser rip-rap provides new habitat and the diffuser plume provides a continual source of zooplankton. In the absence of SONGS these secondarily entrained zooplankton would have been available to the same predators and to the late larval stages of the fodder fish Genyonemus and Seriphus.

3. The diffuser discharges will result in replacement of part of the offshore surface water by a plume consisting of a mixture of nutrient-rich waters from closer to shore and nearer the bottom. The detailed methods used in estimating the amount of nitrate plus nitrite added to the surface waters, and the conversion of these estimates to estimated phytoplankton production, are explained in Plankton Appendix 3.

SONGS will induce a real net increase over present primary production off San Onofre. First, in surface and mid waters where chlorophyll is high, nutrients are low, suggesting that when nutrients get into the high chlorophyll

waters they are taken up rapidly. Conversely, the presence of deeper waters high in nutrients and low in chlorophyll presumably indicates that the phytoplankton there are utilizing nutrients at a lower rate (Plankton Appendix 3). Therefore the nutrients in the bottom waters upwelled by the diffusers will be utilized at a far higher rate when they reach the surface.

Second, the waters replacing the entrained waters will also be high in nutrients and low in productivity. During periods of moderate to strong longshore currents, entrained water will be replaced primarily from longshore and similar depths. Under very sluggish conditions most of the entrained waters will come from offshore. In both cases, the water will be rich in nutrients (Plankton Appendix 3).

SOFT BOTTOM COMMUNITIES

The basis for the predictions can be found in Soft Bottom Communities Appendices 1 and 2.

1. Probable sediment effects were estimated by establishing the existing statistical relationships among abundance, diversity and characteristics of the sediments. Probable changes in the sediments were estimated (very approximately) from information about the weights of various materials in the SONGS' plumes, from information about water movements, and from information about the settling rates of various classes of materials.

2. Some 17% of the benthic species at some time rise into the water column and are at risk to entrainment by the intake or the discharging water. Too little is known about this group to make a firm quantitative estimate of losses, but we expect them to be roughly the same as mysid losses.

We are very uncertain about possible losses of planktonic larvae and the potential effects. This group of plankton is very poorly known. We do have data showing that the larvae of some intertidal and nearshore species are restricted inshore. However, we cannot estimate losses of benthic larvae because we do not know how to estimate mortality caused by the plume. Finally, although we know for some rocky bottom species that have been studied, that larval settlement far exceeds the number needed to maintain the adult population, we do not know if this is always the case, or if it is true for soft bottoms. If it were, likely reductions in larval settlement would have no effect on adult numbers.

It is possible that some intertidal and shallow water species will show reduced adult densities close to SONGS. However, it seems likely that total

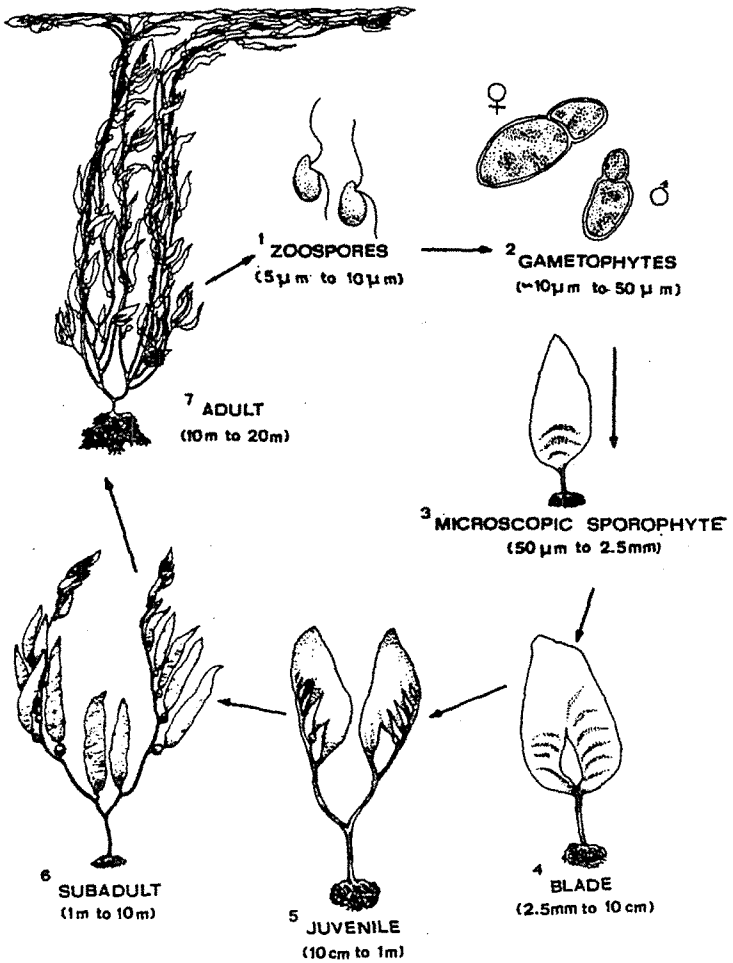
densities will not be significantly reduced, and that any reduction of a particular species will be made up by increased density of others.

3. The enrichment of bottom sediments should have virtually no effect on the production of sport and commercial fish. The enrichment derives from SONGS' killing of organisms in the water column, and so represents a shift of material. The food chains on the soft bottom eventually lead to the same group of sport and commercial fish species as do planktonic food chains; however, there should be some additional losses of this material as it passes up the benthic food chain.

HARD BOTTOM COMMUNITIES

The Hard Benthos Project (Hard Benthos Appendix) has shown clear differences between nearshore and offshore communities on the underside of experimental panels, and some degree of similarity between the communities on panels and on natural boulders. There is also a correlation between these differences and turbidity; and the inshore species grow faster than offshore species at high turbidity.

We believe there is no strong evidence that major changes will occur in this community. Several factors prevent us from making quantitative predictions, including the lack of close similarity between experimental panels and the tops of boulders, and the lack of quantitative relationships between possible changes and turbidity levels.



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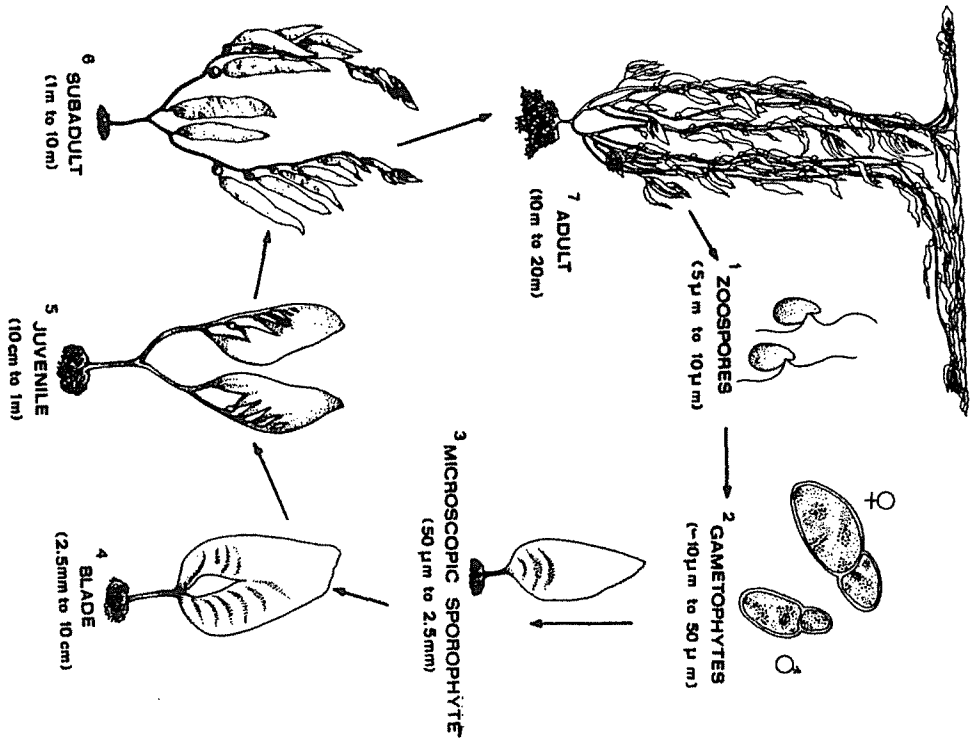


A diagrammatic representation of the Macrocystis life cycle. Stage names and approximate sizes are given.

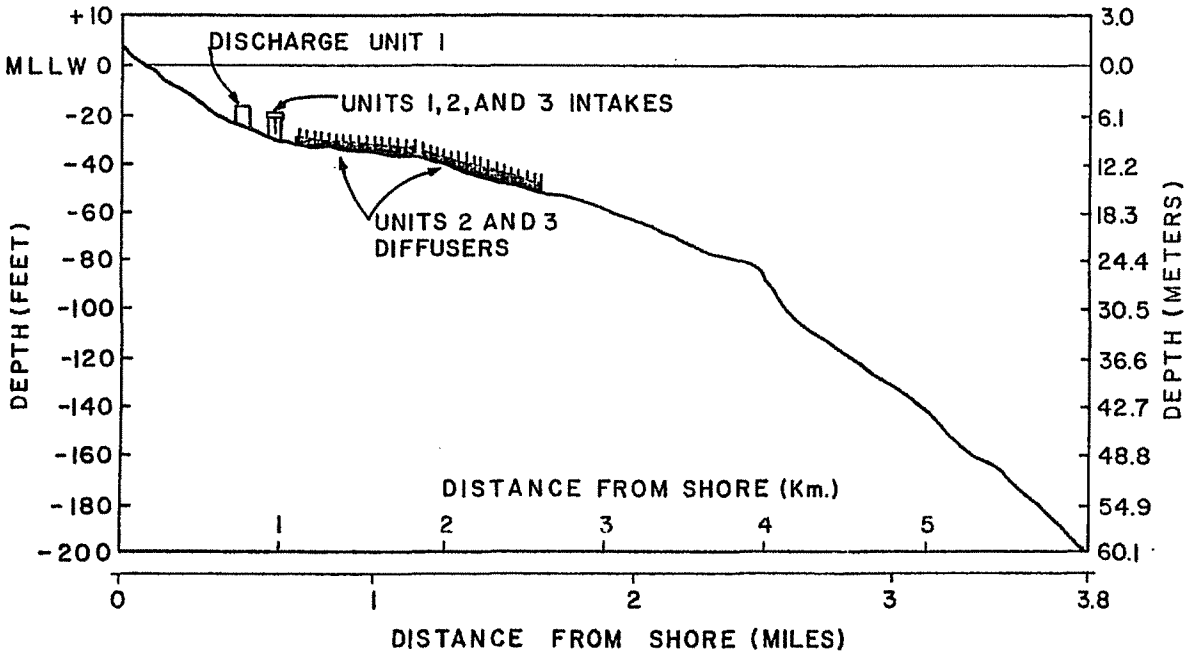
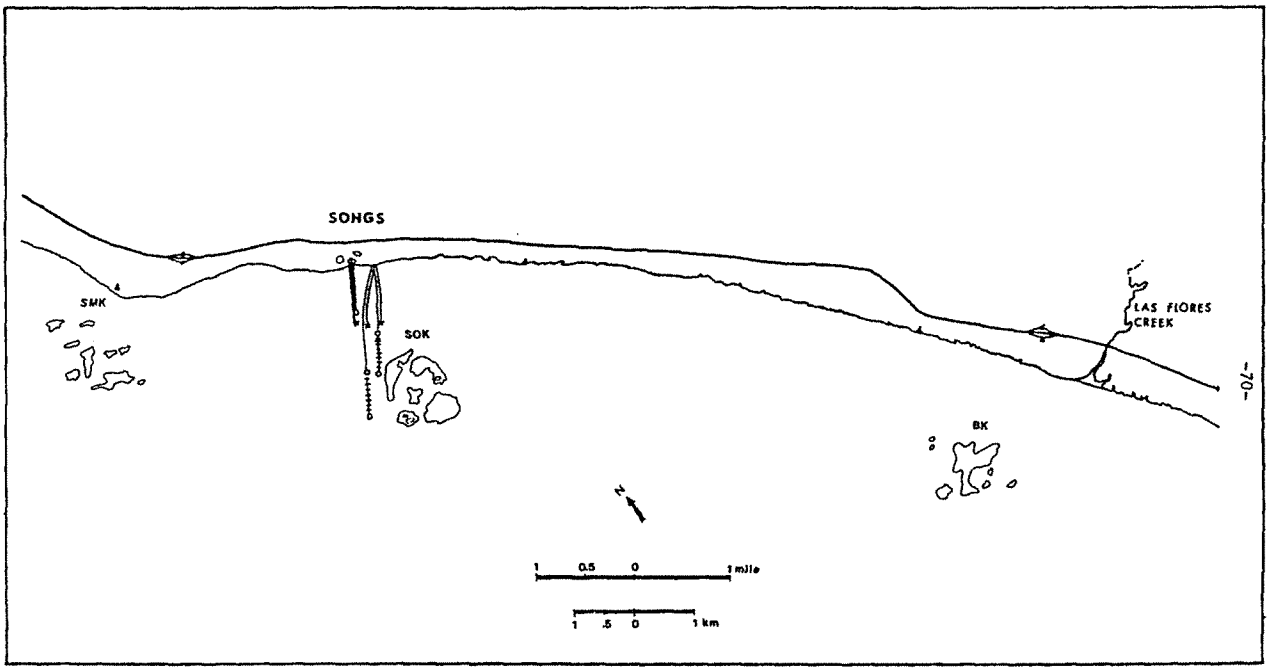


Figure 1. Offshore profile of the cooling system of SONGS Units 1, 2 and 3. (Modified from Figure II-3, Southern California Edison, San Diego Gas and Electric Company, Thermal Effect Study, San Onofre Nuclear Generating Station Units 2 and 3, Vol. 2, September, 1973.)



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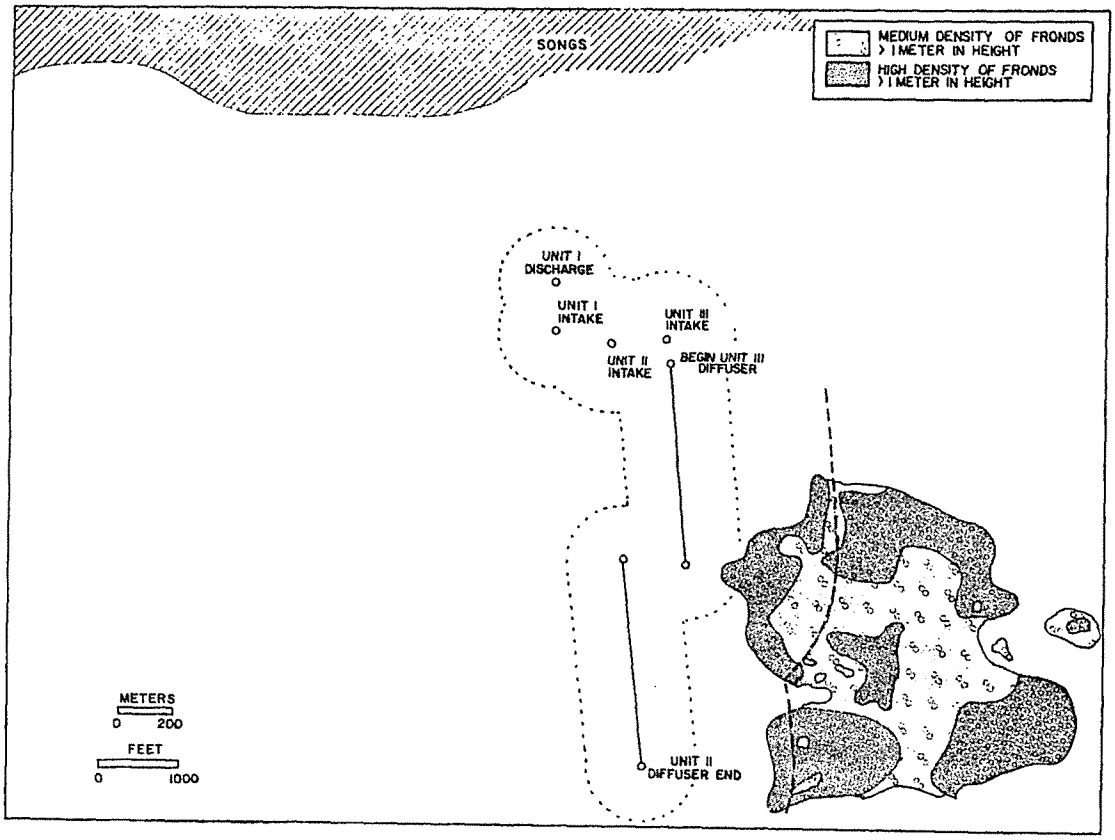
Map 1. Map of the region near SONGS. The kelp beds shown are the high density portions of San Mateo (SMK), San Onofre (SOK), and Barn (BK) kelp beds, as measured in December, 1978.



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Map 2. Map of the coast near San Onofre showing the cooling systems of SONGS Units 1, 2 and 3 and the medium to high density areas of kelp measured in December, 1978, within the San Onofre Kelp (SOK) bed. The boundaries of the areas where the sediments are modified are indicated by dashed lines. The dotted line delimits the area within 1,900 feet of the diffusers as specified in the Coastal Commission Permit of February 28, 1974, Page 3, Item C.

APPENDIX F

EVACUATION MODEL

APPENDIX F

EVACUATION MODEL

"Evacuation," used in the context of offsite emergency response in the event of substantial amount of radioactivity release to the atmosphere in a reactor accident, denotes an early and expeditious movement of people to avoid exposure to the passing radioactive cloud and/or to acute ground contamination in the wake of the cloud passage. It should be distinguished from "relocation" which denotes a post-accident response to reduce exposure from long-term ground contamination. The Reactor Safety Study[1] (RSS) consequence model contains provision for incorporating radiological consequence reduction benefits of public evacuation. Benefits of a properly planned and expeditiously carried out public evacuation would be well manifested in reduction of acute health effects associated with early exposure; namely, in the number of cases of acute fatality and acute radiation sickness which would require hospitalization. The evacuation model originally used in the RSS consequence model is described in WASH-1400[1] as well as in NUREG-0340.[2] However, the evacuation model which has been used herein is a modified version[3] of the RSS model and is, to a certain extent, site-emergency-planning oriented. The modified version is briefly discussed below.

The model utilizes a circular area with a specified radius (such as a 16-km (10-mi) plume exposure pathway emergency planning Zone (EPZ)), with the reactor at the center. It is assumed that people living within portions of this area would evacuate if an accident should occur involving imminent or actual release of significant quantities of radioactivity to the atmosphere.

Significant atmospheric releases of radioactivity would in general be preceded by one or more hours of warning time (postulated as the time interval between the awareness of impending core melt and the beginning of the release of radioactivity from the containment building). For the purpose of calculation of radiological exposure, the model assumes that all people who live in a fan-shaped area (fanning out from the reactor) within the circular zone, with the downwind direction as its median (i.e., those people who would potentially be under the radioactive cloud that would develop following the release) would leave their residences after a specified amount of delay time* and then evacuate. The delay time is reckoned from the beginning of the warning time and is the sum of the time required by the reactor operators to notify the responsible authorities; the time required by the authorities to interpret the data, decide to evacuate, and direct the people to evacuate; and the time required for the people to mobilize and get underway.

The model assumes that each evacuee would move radially outward in the downwind direction with an average effective speed* (obtained by dividing the zone radius by the average time taken to clear the zone after the delay time), over a fixed distance* from the evacuee's starting point, which is somewhat greater than the zone radius. This distance is selected to be 24 km (15 mi) when the selected zone radius is 16 km (10 mi). After reaching the end of the travel distance the evacuee is assumed to receive no further radiation exposure. Persons who are outside the evacuation radius are assumed to remain in place for seven days prior to relocating, unless remaining for that long a period of time would produce a dose greater than 200 rem to the whole body. In that case, relocation takes place after 24 hours, with a dose appropriate to that time period.

The model incorporates a finite length of the radioactive cloud in the downwind direction, which would be determined by the product of the duration over which the atmospheric release would take place and the average windspeed during the release. It is assumed that the front and the back of the cloud formed would move with an equal speed, which would be the same as the prevailing windspeed; therefore, its length would remain constant at its initial value. At any time after the release, the concentration of radioactivity is assumed to be uniform over the length of the cloud. If the delay time were less than the warning time, then all evacuees would have a headstart, i.e., the cloud would be trailing behind the evacuees initially. On the other hand, if the delay time were more than the warning time, then depending on initial locations of the evacuees, there are possibilities that (a) an evacuee will still have a headstart, (b) the cloud would be already overhead when an evacuee starts to leave, or (c) an evacuee would be initially trailing behind the cloud. However, this initial picture of cloud-people disposition would change as the evacuees travel, depending on the

*Assumed to be constant value for all evacuees.

relative speed and position between the cloud and the people. The cloud and an evacuee might overtake one another one or more times before the evacuee would reach his or her destination. In the model, the radial position of an evacuating person, while stationary or in transit, is compared to the front and the back of the cloud as a function of time to determine a realistic period of exposure to airborne radionuclides. The model calculates the time periods during which people are exposed to radionuclides on the ground while they are stationary and while they are evacuating. Because radionuclides would be deposited continually from the cloud as it passed a given location, a person who is under the cloud would be exposed to ground contamination less concentrated than if the cloud had completely passed. To account for this, at least in part, the revised model assumes that persons are (a) exposed to the total ground contamination concentration which is calculated to exist after complete passage of the cloud after they are completely passed by the cloud, (b) exposed to one half the calculated concentration when anywhere under the cloud; and (c) not exposed when they are in front of the cloud. The model provides for use of different values of the shielding protection factors for exposure due to airborne radioactivity and contaminated ground. Breathing rates for stationary and moving evacuees during delay and transit periods are specifically included.

It is realistic to expect that authorities would evacuate persons at distances from the site where exposures above the threshold for causing acute fatality could occur, regardless of the EPZ distance. Figure F-1 illustrates the reduction in acute fatalities that can occur by extending evacuation to distances up to 48 km (30 mi) from the San Onofre site. (The evacuation distance used in the Reactor Safety Study[1] was 40 km (25 mi).) Also illustrated in Figure F-1 is a more pessimistic case for which no early evacuation is assumed. For this case, all persons within 16 km (10 mi) of the plant are assumed to be exposed for the first 24 hours following an accident and are then relocated. Compared to the pessimistic scenario, evacuation of a 48 km (30-mi) zone shows a reduction in acute fatalities of a factor of 10 at 10^{-8} probability.

The model has the same provision for calculation of the economic cost associated with implementation of evacuation as in the original RSS model. For this purpose, the model assumes that for atmospheric releases lasting three hours or less, all people living within a circular area of 8-km (5 mi) radius centered at the reactor plus all people within a 45-degree angular sector within the plume exposure pathway EPZ and centered on the downwind direction will be evacuated and temporarily relocated. However, for releases exceeding three hours, the cost of evacuation is based on the assumption that all people within the plume exposure pathway EPZ would be evacuated and temporarily relocated. For either of these situations, the cost of evacuation and relocation is assumed to be $125 (1980 dollars) per person which includes cost of food, and temporary sheltering for a period of one week.

REFERENCES

1. "Reactor Safety Study," WASH-1400, USNRC Report NUREG-75/014, October 1975.*

2. "Overview of the Reactor Safety Study Consequences Model," USNRC Report NUREG-0340, October 1977.*

3. "A Model of Public Evacuation for Atmospheric Radiological Releases," SAND 78-0092, June 1978.**

*Available from the NRC/GPO Sales Program, Washington, DC 20555, and the National Technical Information Service, Springfield, VA 22161.
**Available for inspection and copying for a fee in the NRC Public Document Room, 1717 H St. N.W., Washington, DC 20555.

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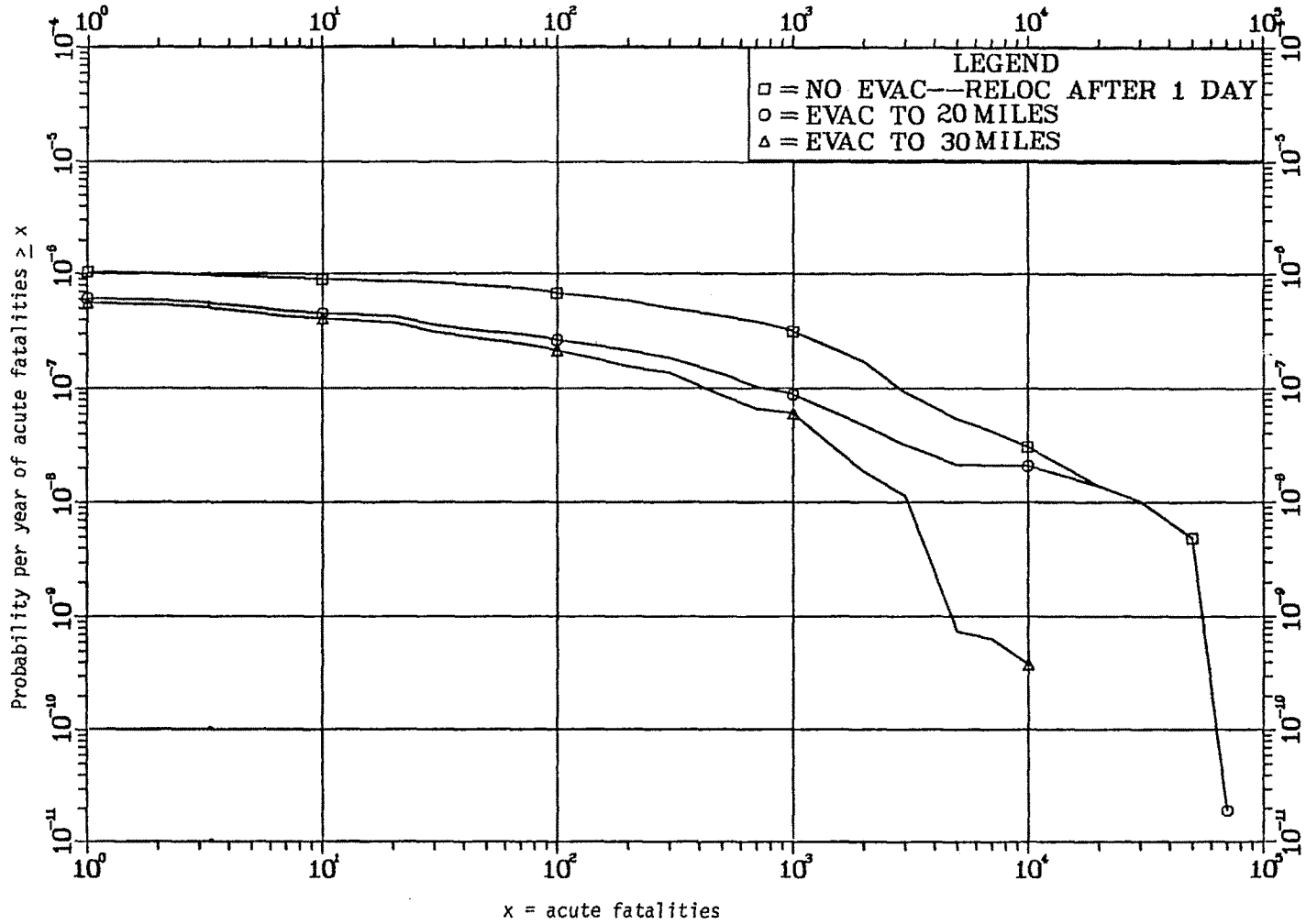

Figure F-1. Probability distribution of acute fatalities. (See Section 7.1.4.6 for discussion of uncertainties in risk estimates.)
(To change miles to kilometers, multiply by 1.6.)

NRC FORM 335 (7-77)

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER (Assigned by DDC): NUREG-0490

4. TITLE AND SUBTITLE (Add Volume No., if appropriate): Final Environmental Statement related to operation of San Onofre Nuclear Generating Station, Units 2 and 3

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3. RECIPIENT'S ACCESSION NO.

7. AUTHOR(S)

5. DATE REPORT COMPLETED: MONTH April, YEAR 1981

9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

DATE REPORT ISSUED: MONTH April, YEAR 1981

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12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

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10. PROJECT/TASK/WORK UNIT NO.

11. CONTRACT NO.

13. TYPE OF REPORT: Final Environmental Statement

PERIOD COVERED (Inclusive dates)

15. SUPPLEMENTARY NOTES: Pertains to Docket Nos. 50-361/362

14. (Leave blank)

16. ABSTRACT (200 words or less)

A Final Environmental Statement related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3 by Southern California Edison Company, et al (Docket Nos. 50-361/362), located in San Diego, California, has been prepared by the Office of Nuclear Reactor Regulation of the Nuclear Regulatory Commission. The statement reports on the staff's review of the impact of operation of the plant. Also included are comments of state and federal government agencies on the Draft Environmental Statement and its Supplement for this project and staff responses to these comments. The NRC staff has concluded, based on a weighing of environmental, technical and other factors, that operating licenses could be granted.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT: Unlimited

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EXHIBIT 31

provides matching funds for cooperative agreements that generally do not exceed $50,000.

MLI. For FY 1996, $709,000 was available for this program. This program will provide funds for cooperative agreements that generally do not exceed $30,000. Cost sharing is encouraged.

Application Forms

IMS mails application forms and program information in General Operating Support. Conservation Project Support and Professional Services Program application packets to museums and other institutions on its mailing list. Applicants may obtain application packets by writing or telephoning the Institute of Museum Services, 1100 Pennsylvania Avenue, NW., Room 609, Washington, DC 20506, (202) 606–8539. Deaf and hearing impaired individuals may call the TTY Line, (202) 606–8636.

To received an application for the Conservation Assessment Program contact the National Institute for Conservation, 3299 K Street, NW., Suite 403, Washington, DC 20007 (202) 625–1495.

To receive an application for the Museum Assessment Programs contact the American Association of Museums, 1225 Eye Street, NW., Washington, DC 20005 (202) 289–1818. After November 18, 1996, contact 1575 Eye Street, NW., Washington, DC 2005 (202) 289–1818.

(Catalog of Federal Domestic Assistance No. 45.301 Institute of Museum Services)

Dated: September 13, 1996.

Diane B. Frankel,

Director, Institute of Museum Services.

[FR Doc. 96–24681 Filed 9–25–96; 8:45 am]

BILLING CODE 7036–01–M

NATIONAL FOUNDATION FOR THE ARTS AND THE HUMANITIES

President's Committee on the Arts and the Humanities: Meeting XXXVII

Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Public Law 92–463), as amended, notice is hereby given that a meeting of the President's Committee on the Arts and the Humanities will be held on October 4, 1996 from 9:30 a.m. to 3:00 p.m. This meeting will be held at the National Gallery of Art, West Building on 6th Street and Constitution Avenue NW., Washington, DC. The meeting will be located in the Lecture Hall, which is to the right through the Galleries. Visitors should use the 6th Street Entrance.

This meeting will be open to the public on a space available basis and will begin with an opening statement by the Chairman. The Executive Director will provide an update on Committee activities and a briefing discussion will be held regarding the report requested by the President. Following a lunch break, the Committee will discuss recommendations to be included in the report.

The President's Committee on the Arts and the Humanities was created by Executive Order in 1982 to advise the President, the two Endowments, and the IMS on measures to encourage private sector support for the nation's cultural institutions and to promote public understanding of the arts and the humanities.

If, in the course of discussion, it becomes necessary for the Committee to discuss non-public commercial or financial information of intrinsic value, the Committee will go into closed session pursuant to subsection (c)(4) of the Government in the Sunshine Act, 5 U.S.C. 552b.

Any interested persons may attend as observers, on a space available basis, but seating is limited in meeting rooms and the staff of the National Gallery will need to know in advance who will be attending. Therefore, for this meeting, individuals wishing to attend are required to notify the staff of the President's Committee in advance at (202) 682–5409 or write to the Committee at 1100 Pennsylvania Avenue NW., Suite 526, Washington, DC 20506.

Dated: September 18, 1996.

Kathy Plowitz-Worden,

Panel Coordinator, Panel Operations, National Endowment for the Arts.

[FR Doc. 96–24682 Filed 9–25–96; 8:45 am]

BILLING CODE 7537–01–M

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–361 and 50–362]

Southern California Edison; San Onofre Nuclear Generating Station, Units 2 and 3; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of amendments to Facility Operating License Nos. NPF–10 and NPF–15, issued to Southern California Edison (the licensee) for the San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, located in San Diego County, California.

Environmental Assessment

Identification of the Proposed Action

By letter dated December 6, 1995, the licensee proposed to change the technical specifications (TSs) to allow an increase in fuel enrichment (Uranium 235) up to 4.8 weight percent. The present TS permit a maximum enrichment of 4.1 weight percent.

Need for Proposed Action

The licensee intends to load fuel into the core during Cycle 9 and subsequent refueling outages which does not currently meet the TSs. By increasing the fuel enrichment, the licensee will implement the fuel strategies developed for SONGS Units 2 and 3.

Environmental Impact of the Proposed Action

The Commission has completed its evaluation of the proposed revision to the TSs and concludes that storage and use of fuel enriched with U–235 up to 4.8 weight percent at SONGS Units 2 and 3 is acceptable. The safety considerations associated with higher enrichments have been evaluated by the NRC staff and the staff has concluded that such changes would not adversely affect plant safety. The proposed changes have no adverse effect on the probability of any accident. As a result, there is no increase in individual or cumulative radiation exposure.

The environmental impacts of transportation resulting from the use of higher enrichment and extended irradiation are discussed in the staff assessment entitled "NRC Assessment of the Environmental Effects of Transportation Resulting from Extended Fuel Enrichment and Irradiation." This assessment was published in the **Federal Register** on August 11, 1988 (53 FR 30355) as corrected on August 24, 1988 (53 FR 32322) in connection with the Shearon Harris Nuclear Power Plant, Unit I: Environmental Assessment and Finding of No Significant Impact. As indicated therein, the environmental cost contribution of an increase in fuel enrichment of up to 5 weight percent U–235 and irradiation limits of up to 60 Gigawatt Days per Metric Ton (GWD/MT) are either unchanged, or may in fact be reduced from those summarized in Table S–4 as set forth in 10 CFR 51.52(c). These findings are applicable to the proposed amendment for SONGS Units 2 and 3. Accordingly, the Commission concludes that this proposed action would result in no significant radiological environmental impact.

With regard to potential nonradiological impacts, the proposed

changes involve systems located within the restricted area as defined in 10 CFR Part 20. It does not affect nonradiological plant effluents and has no other environmental impact. Therefore, the Commission concludes that there are no significant nonradiological environmental impacts associated with the proposed amendment.

The Notice of Consideration of Issuance of Amendment to Facility Operating License, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing in connection with this action was published in the **Federal Register** on April 10, 1996 (61 FR 15997).

Alternative to the Proposed Action

Since the Commission concluded that there are no significant environmental effects that would result from the proposed action, any alternative with equal or greater environmental impacts need not be evaluated.

The principal alternative would be to deny the requested amendment. This would not reduce environmental impacts of plant operation and would result in reduced operational flexibility.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the Final Environmental Statement for SONGS Units 2 and 3, dated April 1981 (NUREG–0490).

Agencies and Persons Contacted

In accordance with its stated policy, on September 19, 1996, the Commission consulted with the California State official, Mr. Steve Hsu of the State Department of Health Services, regarding the environmental impact of the proposed action. The State official had no comments.

Finding of No Significant Impact

Based upon the environmental assessment, the Commission concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to this action, see the application for license amendment dated December 6, 1995. Copies are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC 20555, and at the temporary local public document room located at the Science Library, University of California, Irvine, California 92713.

Dated at Rockville, Maryland, this 19th day of September 1996.

For the Nuclear Regulatory Commission.

Mel B. Fields,

Project Manager, Project Directorate IV–2 Division of Reactor Projects III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 96–24694 Filed 9–25–96; 8:45 am]

BILLING CODE 7590–01–P

Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves; Issued

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of issuance.

SUMMARY: The Nuclear Regulatory Commission (NRC) has issued Generic Letter 96–05 to all holders of operating licenses (except those licenses that have been amended to possession-only status) or construction permits for nuclear power reactors, to (1) discuss the periodic verification of the capability of safety-related motor-operated valves to perform their safety functions consistent with the current licensing basis of nuclear power plants, (2) request that each addressee of this generic letter establish a program, or ensure the effectiveness of its current program, to verify on a periodic basis that safety-related MOVs continue to be capable of performing their safety functions within the current licensing basis of the facility, and (3) require addressees to provide to the NRC a written response relating to implementation of the requested action. This generic letter is available in the NRC Public Document Room under accession number 9609100488.

DATES: The generic letter was issued on September 18, 1996.

ADDRESSEES: Not applicable.

FOR FURTHER INFORMATION CONTACT: Thomas G. Scarbrough, at (301) 415–2794.

SUPPLEMENTARY INFORMATION: NRC regulations require that components that are important to the safe operation of a nuclear power plant, including motor-operated valves (MOVs), be treated in a manner that provides assurance of their performance. Appendix A, "General Design Criteria for Nuclear Power Plants," and Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50) include broad-based requirements in this regard. In 10 CFR 50.55a(f), the NRC requires licensees to comply with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code).

Nuclear power plant operating experience, valve performance problems and MOV research have revealed that the focus of the ASME Code on stroke time and leak-rate testing for MOVs was not sufficient for ensuring the long-term capability of MOVs to perform their design-basis safety functions in light of the design of the valves and the conditions under which they must function. For this reason, on June 28, 1989, the NRC staff issued Generic Letter (GL) 89–10, "Safety-Related Motor-Operated Valve Testing and Surveillance." In GL 89–10, the staff requested that certain actions be taken to ensure the capability of MOVs in safety-related systems to perform their intended functions. The staff issued seven supplements to GL 89–10 that provided additional guidance and information.

GL 89–10 and its supplements provide only limited guidance regarding periodic verification and the measures appropriate to assure preservation of design-basis capability. This generic letter provides more complete guidance regarding periodic verification of safety-related MOVs and supersedes GL 89–10 and its supplements with regard to MOV periodic verification. Although this guidance could have been provided in a supplement to GL 89–10, the staff has prepared this new generic letter to allow closure of the staff review of GL 89–10 programs as promptly as possible.

Dated at Rockville, Maryland, this 18th day of September 1996.

For the Nuclear Regulatory Commission.

Thomas T. Martin,

Director, Division of Reactor Program Management Office of Nuclear Reactor Regulation.

[FR Doc. 96–24695 Filed 9–25–96; 8:45 am]

BILLING CODE 7590–01–P

OFFICE OF MANAGEMENT AND BUDGET

1996 List of Designated Federal Entities and Federal Entities

AGENCY: Office of Management and Budget.

ACTION: Notice.

SUMMARY: This notice provides a list of Designated Federal Entities and Federal Entities, as required by the Inspector General Act of 1978 (IG Act), as subsequently amended.

FOR FURTHER INFORMATION CONTACT: Suzanne Murrin (telephone: 202–395–1040), Office of Federal Financial

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in the proceeding on the petitioner's interest. The petition must also identify the specific aspect(s) of the subject matter of the proceeding as to which petitioner wishes to intervene. Any person who has filed a petition for leave to intervene or who has been admitted as a party may amend the petition without requesting leave of the Board up to 15 days prior to the first prehearing conference scheduled in the proceeding, but such an amended petition must satisfy the specificity requirements described above.

Not later than 15 days prior to the first prehearing conference scheduled in the proceeding, a petitioner shall file a supplement to the petition to intervene that must include a list of the contentions that the petitioner seeks to have litigated in the hearing. Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the petitioner shall provide a brief explanation of the bases of the contention and a concise statement of the alleged facts or expert opinion that support the contention and on which the petitioner intends to rely in proving the contention at the hearing. The petitioner must also provide references to those specific sources and documents of which the petitioner is aware and on which the petitioner intends to rely to establish those facts or expert opinion. The petitioner must provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact. Contentions shall be limited to matters within the scope of the amendments under consideration. The contention must be one that, if proven, would entitle the petitioner to relief. A petitioner who fails to file such a supplement that satisfies these requirements with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing, including the opportunity to present evidence and cross-examine witnesses.

Requests for a hearing and petitions for leave to intervene must be filed with the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemakings and Adjudications Staff, or may be delivered to the Commission's Public Document Room, located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland, by the above date. A copy of the petition should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and to Mary O'Reilly, Attorney, FirstEnergy Legal Department, FirstEnergy Corporation, 76 S. Main Street, Akron, OH 44308, attorney for the licensee.

Nontimely filings of petitions for leave to intervene, amended petitions, supplemental petitions and/or requests for a hearing will not be entertained absent a determination by the Commission, the presiding officer, or the presiding Atomic Safety and Licensing Board that the petition and/or request should be granted based upon a balancing of the factors specified in 10 CFR 2.714(a)(1)(i)–(v) and 2.714(d).

If a request for a hearing is received, the Commission's staff may issue the amendments after it completes its technical review and prior to the completion of any required hearing if it publishes a further notice for public comment of its proposed finding of no significant hazards consideration in accordance with 10 CFR 50.91 and 50.92.

For further details with respect to this action, see the application for amendments dated January 18, 2001 (ADAMS Accession No. ML010230096), as supplemented by letters dated February 20 (ADAMS Accession No. ML010540305) and April 12, 2001 (ADAMS Accession No. ML011130105), which are available for public inspection at the Commission's Public Document Room, located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland, and accessible electronically through the ADAMS Public Electronic Reading Room link at the NRC Web site (*http://www.nrc.gov*). If there are problems accessing the document located in ADAMS, contact the PDB Reference staff at 1–800–397–4209 or 301–415–4737, or send an e-mail to pdr@nrc.gov.

Dated at Rockville, Maryland, this 31st day of May 2001.

For the Nuclear Regulatory Commission.

Lawrence J. Burkhart,

Project Manager, Section 1, Project Directorate I, Division of Licensing Project Management, Office of Nuclear Reactor Regulation.

[FR Doc. 01–15371 Filed 6–18–01; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–361 and 50–362]

Southern California Edison; San Onofre Nuclear Generating Station, Unit Nos. 2 and 3; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (NRC) is considering issuance of an amendment to Facility Operating Licenses Nos. NPF–10 and NPF–15, issued to Southern California Edison Company (SCE or the licensee), for operation of the San Onofre Nuclear Generating Station (SONGS), Units Nos. 2 and 3, located in San Diego County, California.

Environmental Assessment

Identification of Proposed Action

The proposed action would amend the facility license and the technical specifications for SONGS Units 2 and 3, to allow SCE to increase the maximum reactor core power level for each unit from 3390 megawatts thermal (MWt) to 3448 MWt, which is an increase of 1.42 percent of rated core thermal power for SONGS Units 2 and 3.

The proposed action is in accordance with the licensee's application for amendment dated April 3, 2001, and supplemented April 23, May 11, May 25, and May 31, 2001.

The Need for the Proposed Action

The proposed action would permit an increase in the licensed core thermal power from 3390 MWt to 3448 MWt and is needed to allow an increase in the net electrical output of SONGS Units 2 and 3 and, thus, provide additional electrical power to service domestic and commercial areas of the licensee's grid.

Environmental Impacts of the Proposed Action

In support of its request for the proposed power uprate, SCE evaluated the radiological effects of the proposed action, and specifically evaluated its radioactive waste management systems including system/component activity inventories and activity releases associated with the liquid, gaseous, and solid waste management systems, as well as the process and effluent radiological monitoring and sampling systems. In addition, SCE evaluated the non-radiological effects of the proposed action. Based on its review of the licensee's evaluation of the environmental impacts, the NRC staff concludes that the proposed increase in power would not result in a significant

environmental impact as discussed below.

Radiological Environmental Assessment

Radioactive Waste (Radwaste) Management

SCE has evaluated the system/component activity inventories and activity releases associated with the liquid, gaseous, and solid waste management systems, as well as the process and effluent radiological monitoring and sampling systems. SONGS radwaste management and radiation protection analyses are based on the Units 2 and 3 Cycle 1 core activity inventory profile with one percent fuel cladding defects. The licensee has determined that the activity inventories of Cycle 1 core isotopes (primarily some iodine and noble gas isotopes) are greater than the core activity inventories associated with 102 percent of current licensed power, i.e., 3458 MWt. The licensee has also evaluated the dose contributions of iodine, noble gas, and particulate core isotopes for the power uprate conditions. Based on its evaluation, the licensee determined that the core and system activity profiles of record bound (i.e., are equal to, or more severe than) the core and system activity source terms at the proposed uprated power level. Therefore, the licensee has concluded that its operation of the radwaste systems at SONGS Units 2 and 3 will not be impacted by operation at uprated power conditions and the effluents discharged would continue to meet the requirements of 10 CFR part 20 and 10 CFR part 50, Appendix I. Based on the above, the staff has determined that the proposed power uprate will not appreciably affect the ability to process liquid or gaseous radioactive effluents and there are no significant environmental effects from radiological releases.

Dose Consideration

SCE evaluated the effects of power uprate on the radiation sources within the plant and radiation levels during normal and post-accident conditions. Based on its evaluation, the licensee determined that SONGS Units 2 and 3 dose contributions and the activity inventories of Cycle 1 core isotopes (primarily some iodine and noble gas isotopes) are greater than the dose consequences and core activity inventories associated with the 102 percent of the current licensed power, i.e., 3458 MWt, and therefore bound the proposed uprated power level. Further occupational doses for normal operations will be maintained within acceptable limits by the site's as-low-as-reasonably-achievable program, which is required by 10 CFR 20.1101(b).

Therefore, the NRC staff concludes that the radiological doses would remain below the 10 CFR part 100 guidelines and all radiological safety margins are maintained.

Summary

The proposed power uprate will not significantly increase the probability or consequences of accidents, will not involve any new radiological release pathways, will not result in a significant increase in occupational or public radiation exposure, and will not result in significant additional fuel cycle environmental impacts. Accordingly, the NRC staff concludes that there are no significant radiological environmental impacts associated with the proposed action.

Non-Radiological Environmental Assessment

The licensee reviewed the non-radiological environmental impacts of the requested power uprate based on information submitted in the Environmental Report, Operating License Stage, the NRC Final Environmental Statement (FES) related to the operation of San Onofre Nuclear Station, Units 2 and 3, (NUREG–0490, dated April 1981), and the requirements of the Environmental Protection Plan. Based on this review, the licensee concluded that the proposed power uprate would have no significant effect on the non-radiological elements of concern and the plant will be operated in an environmentally acceptable manner as established by the FES. In addition, the licensee states that existing Federal, State, and local regulatory permits presently in effect accommodate the power uprate without modification.

The SONGS units are cooled by once-through cooling water systems, withdrawing cooling water from the Pacific Ocean and discharging it to the ocean through separate underwater diffusers on the ocean bottom. The licensee determined that the differential temperature developed by the cooling system will increase by approximately 0.3°F, increasing the calculated differential to approximately 19.2 °F. The limit on differential temperature allowed by the California Regional Water Quality Control Board, San Diego Region, is 25 °F and includes an allowance of 0.4 °F for increases in thermal power level. The licensee also evaluated other environmental discharges and determined that the small increase in reactor power will not have significant impact on the environment.

SONGS operates in compliance with a National Pollution Discharge Elimination System (NPDES) Permit, which requires all effluents to be closely monitored to assure compliance with the permit levels. Effluent increases due to the power uprate of SONGS Units 2 and 3 are not expected. With regard to potential non-radiological impacts, the proposed action would not change the method of operation at SONGS or the methods of handling effluents. No changes to land use would result and the proposed action does not involve any historic sites. Therefore, no new or different types of non-radiological environmental impacts are expected. Accordingly, the NRC staff concludes that there are no significant non-radiological environmental impacts associated with the proposed action.

Alternatives to the Proposed Action

As an alternative to the proposed action, the NRC staff considered denial of the proposed action (i.e., the ''no-action'' alternative). Denial of the application would result in no change in current environmental impacts. The environmental impacts of the proposed action and the alternative action are similar.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the FES for SONGS Units 2 and 3 dated March 1973.

Agencies and Persons Consulted

In accordance with its stated policy, on June 7, 2001, the NRC staff consulted with the California State official, Mr. Steve Hsu, of the Radiologic Health Branch of the State Department of Health Services, regarding the environmental impact of the proposed action. The State official had no comments.

Finding of No Significant Impact

On the basis of the environmental assessment, the NRC staff concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to the proposed action, see the licensee's letter dated April 3, 2001, and the supplements dated April 23, May 11, May 25, and May 31, 2001, which may be examined, and/or copied for a fee, at the NRC's Public Document Room, located at One White Flint North, 11555

Rockville Pike (first floor), Rockville, Maryland. Publicly available records will be accessible electronically from the ADAMS Public Library component on the NRC Web site, *http://www.nrc.gov,* (the Electronic Reading Room). If you do not have access to ADAMS or if there are problems in accessing the documents located in ADAMS, contact the NRC Public Document Room (PDR) Reference staff at 1–800–397–4209, or 301–415–4737, or by e-mail to *pdr@nrc.gov.*

Dated at Rockville, Maryland this 13th day of June 2001.

For the Nuclear Regulatory Commission.

Joseph E. Donoghue,

Senior Project Manager, Project Directorate IV, Section 2, Division of Licensing Project Management, Office of Nuclear Reactor Regulation.

[FR Doc. 01–15370 Filed 6–18–01; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Discrimination Task Group; Notice of Meetings

In August 2000, the NRC announced the formation of a Discrimination Task Group, which is evaluating the NRC processes used in the handling of discrimination allegations and violations of employee protection standards (Applicable regulations include 10 CFR 30.7, 10 CFR 40.7. 10 CFR 50.7, 10 CFR 60.9, 10 CFR 61.9, 10 CFR 70.7, 10 CFR 76.7, 10 CFR 72.10, 10 CFR 150.20). The group is a management-level review group which is evaluating the Commission's handling of discrimination cases.

The group has developed draft recommendations for changes to the regulatory requirements, the enforcement policy or other agency guidelines as appropriate. The draft recommendations have been released for public comment and can be obtained via the Office of Enforcement web site at http://www.nrc.gov/OE/. Following a pubic comment period on the draft that expires on August 17, 2001, the Task Group will develop a Commission Paper outlining the final recommendations for NRC offices to consider in making changes to their processes.

The Task Group is holding several public stakeholder meetings in various areas of the country to solicit comment on the draft recommendations for changes in the Agency's handling of discrimination issues.

—A public meeting will be held in Chattanooga, TN, on June 25, 2001, at the USNRC Technical Training Center, Osborne Office Center, 5746 Marlin Road, Chattanooga TN 37411 This will be an evening meeting from 7 p.m. to 9 p.m.

—A public meeting will be held, on July 11, 2001, at the USNRC Region III offices located 801 Warrenville Road, Lisle, IL 60532. This will be an evening meeting from 7 p.m. to 9 p.m.

—A public meeting will be held, on July 12, 2001, in Paducah, KY, at the Paducah Community College Engineering Building, Crounse Hall Main Lecture Hall, 4810 Alben Barkely Drive, Paducah, KY. This will be an evening meeting from 7 p.m. to 9 p.m.

—A public meeting will be held on August 9, 2001, at the San Luis Obispo Public Library, Library Conference Room, 995 Palm Street, San Luis Obispo CA. This will be an evening meeting from 7 p.m. to 9 p.m.

—A public meeting will be held on August 14, 2001, at the Waterford Town Hall, 15 Rope Ferry Road, Waterford, CT This will be an evening meeting from 7 p.m. to 9 p.m.

—A public meeting will be held on August 16, 2001, at the USNRC offices in the TWFN Auditorium, located at 11555 Rockville Pike, Rockville, Maryland. The meeting will start at 9:30 a.m.

These meetings are open to the members of the public. Oral or written views regarding the NRC's draft recommendations for improving processes for handling employee protection issues may be presented by the members of the public, including members of the nuclear industry. Persons desiring to make prepared oral presentations or statements should notify Mr. Barry Westreich (Telephone 301/415–3456, e-mail BCW@nrc.gov) five days prior to the meeting date, if possible, so that appropriate arrangements can be made to allow necessary time during the meeting for such a presentation or statements. Use of still, motion picture, and television cameras as well as audio recording devices will be permitted during these meetings.

Further information regarding topics of discussion, whether the meeting has been canceled, rescheduled, or relocated; may be obtained via the Office of Enforcement web site at *http://www.nrc.gov/OE* or by contacting Mr. Barry Westreich between 8 a.m. and 4:30 p.m. EDT.

For those unable to attend one of the public meetings on this issue, comments on the draft report can be submitted via the Office of Enforcement web site at *http://www.nrc.gov/OE.* and may also be submitted in writing addressed to Barry Westreich, Office of Enforcement, U.S. Nuclear Regulatory Commission 11555 Rockville Pike, Rockville, MD, 20852.

This meeting will not be transcribed but, if needed, a meeting report will be available electronically for public inspection on the Office of Enforcement web site at *http://www.nrc.gov/OE* and in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC web site at *http://www.nrc.gov/NRC/ADAMS/index.html* (the Public Electronic Reading Room). The Task Group Charter and other pertinent documents related to Task Group Activities will also be periodically posted and updated on the Office of Enforcement web site.

Dated at Rockville, Maryland this 11th Day of June 2001.

For the Nuclear Regulatory Commission.

Frank Congel,

Director, Office of Enforcement.

[FR Doc. 01–15372 Filed 6–18–01; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Public Workshop on Future Licensing Activities

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of public workshop.

SUMMARY: The Nuclear Regulatory Commission (NRC) has scheduled a public workshop to inform the public of the current and proposed activities of the NRC staff regarding future applications and to solicit public concerns and feedback on identified issues and challenges.

DATES: July 25, 2001, from 9 a.m.–8 p.m.; July 26, 2001, from 9 a.m.–1 p.m.

ADDRESSES: The workshop will be held in the NRC's Auditorium at Two White Flint North, 11545 Rockville Pike, Rockville, Maryland 20852–2738.

FOR FURTHER INFORMATION CONTACT: Contact Eric Benner, Mail Stop O–12D1, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. Members of the public may pre-register for this meeting by contacting Eric Benner at (800) 368–5642, ext. 1171, or by Internet at *ejb1@nrc.gov* by July 20, 2001.

The NRC maintains an Agencywide Documents Access and Management System (ADAMS) which provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public

EXHIBIT 33

[7590-01-P]

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50-361, 50-362, and 72-41; NRC-2015-0023]

Southern California Edison Company

San Onofre Nuclear Generating Station, Units 2 and 3

AGENCY: Nuclear Regulatory Commission.

ACTION: Draft environmental assessment and finding of no significant impact; request for comment.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is issuing for public comment a draft environmental assessment (EA) and finding of no significant impact (FONSI) related to a request to amend Facility Operating License Nos. NPF-10 and NPF-15 and Docket No. 72-41, issued to the Southern California Edison Company (SCE or "the licensee"), for operation of the San Onofre Nuclear Generating Station, Units 2 and 3 (hereinafter "SONGS" or "the facility"), including the general-license Independent Spent Fuel Storage Installation (ISFSI), located in San Diego County, California. The requested amendment would permit licensee security personnel to use certain firearms and ammunition feeding devices not previously permitted, notwithstanding State, local and certain Federal firearms laws or regulations that otherwise prohibit such actions.

DATES: Submit comments by **December 10, 2015**. Comments received after this date will be considered if it is practical to do so, but the Commission is able to ensure consideration only for comments received before this date. Any potential party as defined in § 2.4 of title 10 of the

Code of Federal Regulations (10 CFR), who believes access to sensitive unclassified non-safeguards information (SUNSI) is necessary to respond to this notice must request document access by **November 20, 2015**.

ADDRESSES: You may submit comments by any of the following methods (unless this document describes a different method for submitting comments on a specific subject):

- **Federal Rulemaking Web site:** Go to http://www.regulations.gov and search for Docket ID **NRC-2015-0023**. Address questions about NRC dockets to Carol Gallagher; telephone: 301-415-3463; e-mail: Carol.Gallagher@nrc.gov. For technical questions, contact the individual in the FOR FURTHER INFORMATION CONTACT section of this document.
- **Mail comments to:** Cindy Bladey, Office of Administration, Mail Stop: OWFN-12-H08, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

For additional direction on obtaining information and submitting comments, see "Obtaining Information and Submitting Comments" in the SUPPLEMENTARY INFORMATION section of this document.

FOR FURTHER INFORMATION CONTACT: Marlayna Vaaler, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; telephone: 301-415-3178, Marlayna.Vaaler@nrc.gov.

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID **NRC-2015-0023** when contacting the NRC about the availability of information for this action. You may obtain publicly-available information related to this action by any of the following methods:

- **Federal Rulemaking Web site:** Go to http://www.regulations.gov and search for Docket ID **NRC-2015-0023**.
- **NRC's Agencywide Documents Access and Management System (ADAMS):** You may obtain publicly-available documents online in the ADAMS Public Documents collection at http://www.nrc.gov/reading-rm/adams.html. To begin the search, select "ADAMS Public Documents" and then select "Begin Web-based ADAMS Search." For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1-800-397-4209, 301-415-4737, or by e-mail to pdr.resource@nrc.gov. The ADAMS accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in the SUPPLEMENTARY INFORMATION section. The applications for amendments for SONGS, dated August 28, 2013, as supplemented by a letter dated February 10, 2015, contain SUNSI and are being withheld from public disclosure.
- **NRC's PDR:** You may examine and purchase copies of public documents at the NRC's PDR, Room O1-F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

B. Submitting Comments

Please include Docket ID **NRC-2015-0023** in your comment submission.

The NRC cautions you not to include identifying or contact information that you do not want to be publicly disclosed in your comment submission. The NRC posts all comment submissions at http://www.regulations.gov as well as entering the comment submissions into ADAMS. The NRC does not routinely edit comment submissions to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the NRC, then you should inform those persons not to include identifying or contact information that they do not want to be publicly disclosed in their comment submission. Your request should state that the NRC does not routinely edit comment submissions to remove such information before making the comment submissions available to the public or entering the comment submissions into ADAMS.

II. Introduction

The NRC is considering a request to amend Facility Operating License Nos. NPF-10 and NPF-15 and Docket No. 72-41, issued to SCE for the operation of SONGS, Units 2 and 3, including the general-license ISFSI, located in San Diego County, California, in accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit." Therefore, as required by 10 CFR 51.21, "Criteria for and identification of licensing and regulatory actions requiring environmental assessments," and 10 CFR 51.33, "Draft finding of no significant impact; distribution," the NRC has prepared a draft EA documenting its finding. The requested amendment would permit licensee security personnel to use certain firearms and ammunition feeding devices not previously permitted, notwithstanding State, local, and certain Federal firearms laws or regulations that otherwise prohibit such actions.

III. Draft Environmental Assessment and Finding of No Significant Impact

Identification of the Proposed Action:

The proposed action would permit security personnel at SONGS during the performance of their official duties, to transfer, receive, possess, transport, import, and use certain firearms and large capacity ammunition feeding devices not previously permitted to be owned or

possessed, notwithstanding State, local, and certain Federal firearms laws, or regulations that otherwise prohibit such actions.

The proposed action is in accordance with the SONGS application dated August 28, 2013 (ADAMS Accession No. ML13242A277), as supplemented by letters dated December 31, 2013 (ADAMS Accession No. ML14007A496), May 15, 2014 (ADAMS Accession No. ML14139A424), and February 10, 2015 (ADAMS Accession No. ML15044A047).

The Need for the Proposed Action:

The proposed action would allow the transfer, receipt, possession, transportation, importation, and use of those firearms and devices needed in the performance of official duties required for the protection of SONGS and associated special nuclear materials, consistent with the SONGS NRC-approved security plan.

Environmental Impacts of the Proposed Action:

The NRC has completed its evaluation of the proposed action and concludes that the proposed action would only allow the use of those firearms and devices necessary to protect SONGS and associated special nuclear materials, consistent with the SONGS NRC-approved security plan. Therefore, the proposed action would not significantly increase the probability or consequences of any accidents. In addition, the proposed action would not change the types or the amounts of any effluents that may be released offsite. There would also be no significant increase in occupational or public radiation exposure. Therefore, there would be no significant radiological environmental impacts associated with the proposed action.

The proposed action would not impact land, air, or water resources, including biota. In addition, the proposed action would not result in any socioeconomic or environmental justice impacts or impacts to historic and cultural resources. Therefore, there would also be no significant non-radiological environmental impacts associated with the proposed action.

Accordingly, the NRC concludes that the issuance of the requested amendment would not result in significant environmental impacts.

The NRC will publish in the *Federal Register* a copy of the final EA as part of the final FONSI.

Environmental Impacts of the Alternatives to the Proposed Action:

As an alternative to the proposed action, the NRC staff considered denying the proposed action (i.e., the "no-action" alternative). Denial of the license amendment request would result in no change to current environmental conditions at SONGS.

Alternative Use of Resources:

The proposed action would not involve the use of any resources.

Agencies and Persons Consulted:

The staff did not consult with any Federal agency or California state agencies regarding the environmental impact of the proposed action.

IV. Finding of No Significant Impact

The licensee has requested a license amendment to permit licensee security personnel, in the performance of their official duties, to transfer, receive, possess, transport, import, and use certain firearms and large capacity ammunition feeding devices not previously permitted to be owned or possessed, notwithstanding State, local, and certain Federal firearms laws or regulations that would otherwise prohibit such actions.

On the basis of the information presented in this environmental assessment, the NRC concludes that the proposed action would not cause any significant environmental impact and would not have a significant effect on the quality of the human environment. In addition, the NRC has determined that an environmental impact statement is not necessary for the evaluation of this proposed action.

Other than the licensee's letter dated August 28, 2013, there are no other environmental documents associated with this review. This document is available for public inspection as indicated above.

Dated at Rockville, Maryland, this 3rd day of November, 2015.

For the Nuclear Regulatory Commission.

/RA/

Bruce A. Watson, CHP, Chief
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery
and Waste Programs
Office of Nuclear Material Safety and Safeguards

EXHIBIT 34

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

NUREG-1757, Vol. 3, Rev. 1

Consolidated Decommissioning Guidance

Financial Assurance, Recordkeeping, and Timeliness

Final Report

Office of Federal and State Materials and
Environmental Management Programs

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NRC publications in the NUREG series, NRC regulations, and *Title 10, Energy*, in the Code of *Federal Regulations* may also be purchased from one of these two sources.

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   Internet: bookstore.gpo.gov
   Telephone: 202-512-1800
   Fax: 202-512-2250
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   Springfield, VA 22161–0002
   www.ntis.gov
   1–800–553–6847 or, locally, 703–605–6000

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Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at—
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These standards are available in the library for reference use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from—
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U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

NUREG-1757, Vol. 3, Rev. 1

Consolidated Decommissioning Guidance

Financial Assurance, Recordkeeping, and Timeliness

Final Report

Manuscript Completed: February 2012
Date Published: February 2012

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Office of Federal and State Materials and
Environmental Management Programs

EXHIBIT 35

NUREG-0586, Supplement 1
Volume 1

Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities

Supplement 1

Regarding the Decommissioning of Nuclear Power Reactors

Main Report, Appendices A through M

Final Report

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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American National Standards Institute
11 West 42nd Street
New York, NY 10036–8002
www.ansi.org
212–642–4900

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NUREG-0586, Supplement 1
Volume 1

Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities

Supplement 1

Regarding the Decommissioning of Nuclear Power Reactors

Main Report, Appendices A through M

Final Report

Manuscript Completed: October 2002
Date Published: November 2002

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Abstract

This document is a supplement to the U.S. Nuclear Regulatory Commission (NRC) document *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* issued in 1988 (NUREG-0586, referred to here as the 1988 Generic Environmental Impact Statement [GEIS]). This Supplement was prepared because of technological advances in decommissioning operations, experience gained by licensees, and changes made to NRC regulations since the 1988 GEIS.

This Supplement updates the information provided in the 1988 GEIS. It is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power reactors as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license. This Supplement addresses only the decommissioning of nuclear power reactors licensed by the NRC. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS to explicitly consider high-temperature gas-cooled reactors and fast breeder reactors. This document can be considered a stand-alone document for power reactor facilities such that readers should not need to refer back to the 1988 GEIS. The environmental impacts described in this Supplement supercede those described for power reactor facilities in the 1988 GEIS.

The scope of this Supplement is based on the decommissioning activities performed to remove radioactive materials from structures, systems, and components from the time that the licensee certifies that it has permanently ceased power operations until the license is terminated. The scope of the document was determined through public scoping meetings and meetings with other Federal agencies and the nuclear industry. An evaluation process was then developed to determine environmental impacts from nuclear power reactor facilities that are being decommissioned. The evaluation process involved determining the specific activities that occur during reactor decommissioning and obtaining data from site visits and from licensees at reactor facilities currently being decommissioned. The data obtained from the sites were analyzed and then evaluated against a list of variables that defined the parameters for facilities that are currently operating but which will one day be decommissioned. This evaluation resulted in a range of impacts for each environmental issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

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Executive Summary

This document is a supplement to the U.S. Nuclear Regulatory Commission (NRC) document *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities,* issued in 1988 (NUREG-0586, referred to hereafter as the 1988 Generic Environmental Impact Statement [GEIS]).[(a)] As a supplement, this document considers the technological advances in decommissioning, the experience gained by licensees, and changes made to NRC regulations since the 1988 GEIS. The information from the 1988 GEIS that is still current and applicable to permanently shut down and currently operating commercial nuclear power reactors is included here. This Supplement is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power reactors as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license.

The NRC elected to supplement the GEIS:

(1) to further the purposes of the National Environmental Policy Act (NEPA)

(2) to update the information in the GEIS

(3) to provide additional information to the public on decommissioning activities

(2) to establish an envelope of environmental impacts that could be associated with decommissioning activities.

Unlike the 1988 GEIS, which took a broad look at decommissioning of a variety of sites and activities, this Supplement addresses only nuclear power reactors licensed by the NRC. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS and considers the existing permanently shut down high-temperature gas-cooled reactor and fast breeder reactor. It does not include research and test reactors or the power reactor facilities that have been involved in a significant accident resulting in large-scale contamination of structures, systems, and components (SSCs). It also does not include other types of fuel-cycle facilities, such as fuel-reprocessing plants or small mixed oxide fuel-fabrication plants.

The intent of this Supplement is to consider in a comprehensive manner all aspects related to the radiological decommissioning of nuclear reactor facilities by incorporating updated information, regulations, and analyses. Since the 1988 GEIS was written, the NRC and the industry have gained substantially more nuclear power facility decommissioning experience. Based on the number of reactors shut down and the date that they permanently ceased

(a) The GEIS is considered "generic" in that it evaluates environmental impacts from decommissioning activities common to a number of nuclear power facilities.

operations, over 200 facility-years' worth of decommissioning experience have accumulated since the NRC published the 1988 GEIS. Currently, there are 19 commercial power reactor facilities in the decommissioning process. This includes nine that permanently ceased operations after the NRC published the 1988 GEIS. Since the 1988 GEIS, there are three facilities that have completed decommissioning and terminated their licenses. There are also new technologies and approaches applicable to decommissioning that the 1988 GEIS does not address. The regulations for decommissioning reactors have also undergone significant changes since the 1988 GEIS.

Scope of the Supplement

The content of this Supplement was initially defined by the scope of the 1988 GEIS and was modified based on current decommissioning regulations, input received during four public scoping meetings, letters and comments received during the scoping period, and meetings between the NRC and the U.S. Environmental Protection Agency (EPA) and the Council on Environmental Quality (CEQ). The public comments received during the scoping process that were considered to be with the scope of the environmental review are provided in Volume 2 Appendix N. The NRC staff published for comment Supplement 1 to the GEIS in October 2001. Public meetings in San Francisco, California, Boston Massachusetts, Chicago, Illinois and Atlanta, Georgia were held in December, 2001 to describe the preliminary results of the NRC environmental review, to answer questions, and to provide members of the public with information to assist them in formatting comments on the draft Supplement. All comments received on the draft Supplement were considered by the staff in developing the final document and are presented in Appendices O and P.

The scope of this Supplement is based on the decommissioning activities performed to remove radioactive materials from SSCs from the time that the licensee certifies that it has permanently ceased power operations until the license is terminated. As a result, the activities performed before permanent cessation of operations (except for decommissioning planning) or impacts that are related to the decision to permanently cease operations (for example, the impact from the loss of generation capacity) are outside the scope of this document.

The Commission defines decommissioning as "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." The staff has included activities that are directly related to the removal of radioactive material from the facility or that must be performed in order to facilitate the removal of contaminated SSCs, as well as the activities and impacts related to the removal of uncontaminated SSCs (such as the intake structure or cooling towers) that were required for the operation of the reactor.

The decommissioning process continues until the licensee requests termination of the license and demonstrates that radioactive material has been removed to the levels that permit

termination of the NRC license. At that point, the NRC no longer has jurisdiction over the site and the owner of the site is no longer subject to NRC regulations. As a result, activities performed after license termination and the resulting impacts are outside the scope of this Supplement. These activities may include any non-NRC required monitoring, site restoration (grading, planting of vegetation, etc.), continued dismantlement (removal of uncontaminated structures or those that have been radiologically decontaminated), or continued use of the site for activities such as power production using natural gas, oil, or coal.

Any potential radiological impacts following license termination that are related to activities performed during the decommissioning period are not considered in this Supplement. Those impacts are covered by the *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities* (NUREG-1496). Nonradiological impacts following license termination that are related to activities performed during the decommissioning period are considered in this Supplement.

Levels of Significance and Applicability of Environmental Impacts

This Supplement provides a measure of (a) the significance and severity of potential environmental impacts and (b) the applicability of these impacts to a variety of plants both permanently shut down and operating. The significance of the environmental impacts is described as either SMALL, MODERATE or LARGE. The applicability of these impacts to a variety of plants is categorized as either generic or site-specific.

Levels of Significance: For decommissioning, the staff is using a standard of significance derived from the CEQ terminology for "significantly" (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

SMALL - Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE - Environmental impacts are sufficient to alter noticeably but not to destabilize important attributes of the resource.

LARGE - Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the NRC staff assumed that ongoing mitigation measures would continue (including those mitigation

measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

Applicability: In addition to determining the significance of environmental impacts, this Supplement includes a determination of whether the analysis of the environmental issues could be applied to all plants, and whether additional mitigation measures would be warranted. An environmental issue may be assigned to one of two categories:

- Generic - For each environmental issue, the analysis reported in this Supplement shows the following:

  (1) Environmental impacts associated with the issue have been determined to apply either to all plants, or for some issues to plants of a specific size, specific location or having a specific type of cooling system or site characteristics, and

  (2) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

  (3) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

- Site-specific - For each environmental issue that was determined to be site-specific, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required. An example of a site-specific issue is threatened and endangered species.

Use and Development of this Supplement

This Supplement can be used by the public to understand the decommissioning process, the activities performed during decommissioning, and the potential environmental impacts resulting from these activities. It identifies activities that can be bounded by a generic evaluation. Licensees can rely on the information in this Supplement as a basis for meeting the requirements in 10 CFR 50.82(a)(6)(ii). This requirement states that the licensee must not perform any decommissioning activity that causes any significant environmental impact not previously reviewed. The NRC staff will also rely on this Supplement as a basis for determining if anticipated decommissioning impacts require an additional review.

The staff first created an initial list of environmental issues and activities that this Supplement should address. The initial list of environmental issues was developed from issues (such as air

quality, aquatic ecology, and radiological impacts) identified in the 1988 GEIS and in the list specified in 10 CFR Part 51, Subpart A, Appendix B, for license renewal. This list was used because it represents the potential impacts associated with nuclear power facilities. The initial list of decommissioning activities was modified based on experience, public participation in the scoping process, site visits to six facilities currently being decommissioned, and meetings with EPA and CEQ. After compiling the issue and activity lists, the staff assessed which activities might have environmental impacts for each of the issues. The next step was to identify the variables that might affect the decommissioning impact for a specific issue and activity. For example, the proximity of the plant to a barge slip or railroad might affect the licensee's decision to remove the steam generator or other large components intact and ship them to a waste site. If the barge slip needs additional dredging, or an additional railroad line needs to be installed, then the environmental impacts may change.

The analyses in this Supplement include data from both operating and decommissioning facilities in order to appropriately span the range of impacts that could be expected. Data from decommissioning facilities was used to determine whether the potential impacts from decommissioning activities for the various issues are generic or site-specific. Data from operating facilities were used to ensure that this Supplement will be valid for all commercial nuclear power reactors.

Alternatives

The alternative to the action of decommissioning is not to decommission the facility. The option to restart the reactor is not considered to be an alternative to decommissioning because the decision to permanently cease operation prevents the licensee from operating the reactor without a significant safety and environmental review by the NRC staff.

The alternative to decommissioning at the end of the licensing period is a "no action" alternative, implying that a licensee would simply abandon or leave a facility after ceasing operations. NRC regulations do not allow the option of not decommissioning. Once the facility permanently ceases operation, if the licensee does not conduct decommissioning activities to an extent that meets the license termination criteria in 10 CFR Part 20, Subpart E, then the license will not be terminated (although the licensee will not be authorized to operate the reactor). The licensee will be required to comply with the necessary requirements for the operating license. As a result, the environmental impacts for maintaining the nuclear reactor facility will be considered to be in the bounds of the appropriate, previously issued Environmental Impact Statements. Under NRC regulations, the original operating license for a nuclear power plant is issued for up to 40 years. The license may be renewed for periods of up to 20 years if NRC requirements are met. However, at the end of the licensing period (whether it has been extended or not), the regulations require that the facility be decommissioned.

Conclusions

Table ES-1 presents each evaluated environmental issue and identifies whether the issue is considered generic or site-specific. If the issue is considered generic, then it is assigned a significance level of either SMALL, MODERATE or LARGE. Of the environmental issues assessed, most of the impacts are generic and SMALL for all plants regardless of the activities and identified variables (see Appendix E for a list of the variables). The two issues determined to be site-specific are threatened and endangered species and environmental justice. Four issues are considered to be conditionally site-specific.

- land use involving offsite areas to support decommissioning activities
- aquatic ecology for activities beyond the operational area
- terrestrial ecology for activities beyond the operational area
- cultural and historic resources for activities beyond the operational area with no current cultural and historic resource survey.

The operational area is defined as the portion of the plant site where most or all of the site activities occur, such as reactor operation, materials and equipment storage, parking, substation operation, facility service, and maintenance. This includes areas within the protected area fences, the intake, discharge, cooling, and associated structures as well as surrounding paved, graveled, maintained landscape, or other maintained areas.

Licensees undergoing or planning decommissioning of a commercial nuclear power reactor can use this Supplement in support of their evaluation of the environmental consequences from decommissioning. The impacts identified in this Supplement are designed to span the range of impacts from all plants that are currently permanently shut down as well as the plants that are currently operating, including the plants that have or may renew their licenses beyond the original 40-year license; a renewed license can be issued for a period not to exceed 20 years beyond the expiration of the operating license. When planning a specific decommissioning activity, licensees that fall within the bounds of the impacts, as described in Chapter 4, may proceed with the activity with no further analysis. However, if the planned activity could result in environmental impacts greater than those predicted by this supplement, then the activity cannot be performed until the licensee performs a site-specific analysis of the activity. Depending on the results of the site-specific evaluation, the staff may determine that it is appropriate to consult with another agency (such as the U.S. Fish and Wildlife Service or a State Historic Preservation Office). If the activity would result in an impact that is outside the bounds of the GEIS or other environmental assessments, the licensee would be required to submit a license-amendment request.

Table ES-1. Summary of the Environmental Impacts from Decommissioning Nuclear Power Facilities

Issue	Generic	Impact
Onsite/Offsite Land Use		
- Onsite land use activities	Yes	SMALL
- Offsite land use activities	No	Site-specific
Water Use	Yes	SMALL
Water Quality		
- Surface water	Yes	SMALL
- Groundwater	Yes	SMALL
Air Quality	Yes	SMALL
Aquatic Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Terrestrial Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Threatened and Endangered Species	No	Site-specific
Radiological		
- Activities resulting in occupational dose to workers	Yes	SMALL
- Activities resulting in dose to the public	Yes	SMALL
Radiological Accidents	Yes	SMALL
Occupational Issues	Yes	SMALL
Cost	NA[a]	NA
Socioeconomic	Yes	SMALL
Environmental Justice	No	Site-specific
Cultural and Historic Resource Impacts		
- Activities within the operational areas	Yes	SMALL
- Activities beyond the operational areas	No	Site-specific
Aesthetics	Yes	SMALL
Noise	Yes	SMALL
Transportation	Yes	SMALL
Irretrievable Resources	Yes	SMALL

(a)A decommissioning cost assessment is not a specific National Environmental Policy Act (NEPA) requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

Abbreviations/Acronyms

µGy	microGray(s)
µSv	microSieverts
ac	acre(s)
AEA	Atomic Energy Act of 1954
AEC	U.S. Atomic Energy Commission
ALI	annual limits on intake
ALARA	as low as reasonably achievable
ANPR	advance notice of proposed rulemaking
BLM	Bureau of Land Management
BMP	best management practice
Bq	Bequerel(s)
BWR	boiling water reactor
C	Celsius
CAA	Clean Air Act
CDE	committed dose equivalent
CEDE	committed effective dose equivalent
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
Ci	Curie
CWA	Clean Water Act
DAC	derived air concentration
dB	decibel
dBA	A-weighted sound levels
dBC	C-weighted sound levels
DBA	design basis accident
DDREF	dose or dose rate effectiveness factor
DE	dose equivalent
DNL	day-night average sound level
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation

EA	environmental assessment
EDE	effective dose equivalent
EIS	environmental impact statement
EJ	environmental justice
EPA	U.S. Environmental Protection Agency
ER	environmental report
ESA	Endangered Species Act of 1973
ES&H	environment, safety and health
F	Fahrenheit
FAA	Federal Aviation Administration
FBR	fast breeder reactor
FES	final environmental statement
FHA	Federal Housing Administration
FR	Federal Register
FSAR	Final Safety Analysis Report
ft	foot/feet
FWPCA	Federal Water Pollution Control Act (also known as the Clean Water Act of 1977)
FWS	U.S. Fish and Wildlife Service
gal.	gallon(s)
GEIS	Generic Environmental Impact Statement
gpd	gallons per day
gpm	gallons per minute
GTCC	Greater-than-Class-C (waste)
Gy	gray(s)
ha	hectare(s)
HDA	high decommissioning activity
HEPA	high-efficiency particulate air (filter)
HLW	high-level waste
h	hour
HTGR	high-temperature gas-cooled reactor
HUD	U.S. Department of Housing and Urban Development
HVAC	heating, ventilation, and air conditioning
IAEA	International Atomic Energy Agency
in.	inch(es)
I&C	instrumentation and control

ICRP	International Commission on Radiological Protection
ISFSI	independent spent fuel storage installation
kg	kilogram(s)
km	kilometer(s)
kV	kilovolt(s)
kWh	kilowatt hour(s)
L	liter(s)
LDA	low-decommissioning activity
LER	licensee event report
LET	linear energy transfer
LLW	low-level waste
LOS	level of service
LRA	license renewal application
LTP	license termination plan
LWR	light water reactor
m	meter(s)
m^3/d	cubic meters per day
m^3/s	cubic meters per second
MARSSIM	Multi-agency Radiation Survey and Site Investigation Manual, NUREG-1575
MBTA	Migratory Bird Treaty Act of 1918
mi	mile(s)
mGy	milliGray(s)
MPC	maximum permissible concentrations
mrad	millirad(s)
mrem	millirem(s)
MRS	monitored retrievable storage
mSv	milliSievert(s)
MTHM	metric tonnes of heavy metal
MT	metric ton(s) (or tonne[s])
MTU	metric ton(s)-uranium
MW	megawatt(s)
MWd/MTU	megawatt-days per metric ton of uranium
MW(e)	megawatt(s) electric
MW(t)	megawatt(s) thermal
MWh	megawatt hour(s)

Abbreviations/Acronyms

NA	not applicable
NAS	National Academy of Sciences
NBS	National Bureau of Standards

NCRP	National Council on Radiation Protection and Measurements
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act of 1969
NHPA	National Historic Preservation Act of 1966
NIST	National Institute of Standards and Technology
NMFS	National Marine Fisheries Service
NO_x	nitrogen oxide(s)
NPDES	National Pollutant Discharge Elimination System
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NWPA	Nuclear Waste Policy Act of 1982
ODCM	Offsite Dose Calculation Manual
OSHA	Occupational Safety and Health Administration
PAG	protective action guide
PCBs	polychlorobiphenyls
PEL	permissible exposure limit
POL	possession-only license
PPE	personal protective equipment
PSDAR	post-shutdown decommissioning activities report
PV	pressure vessel
PWR	pressurized water reactor
QA/QC	quality assurance/quality control
RCRA	Resource Conservation and Recovery Act of 1976
RCS	reactor coolant system
ROW	right-of-way/rights-of-way
RPV	reactor pressure vessel
SARA	Superfund Amendments and Reauthorization Act
SHPO	State Historic Preservation Officer
SI	Systeme Internationale (international system of units)
SO_2	sulfur dioxide
SO_x	sulfur oxide(s)
SSCs	structures, systems, and components
Sv	sievert(s)

Abbreviations/Acronyms

TEDE	total effective dose equivalent
THPO	Tribal Historic Preservation Officer
UNSCEAR	United Nations Scientific Committee on The Effects of Atomic Radiation
USC	United States Code
USFWS	U.S. Fish and Wildlife Service
VOC	volatile organic compound
VRM	Visual Resource Management (system)
wk	week(s)
YNPS	Yankee Nuclear Power Station
yr	year(s)

1.0 Introduction

1.1 Purpose and Need for This Supplement

This document supplements the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NRC 1988), issued in 1988 (NUREG-0586, referred to hereafter as the 1988 GEIS) for power reactor facilities. This Supplement updates information provided in the 1988 GEIS by considering technological advances in decommissioning activities gained since 1988 and changes in U.S. Nuclear Regulatory Commission (NRC) regulations and, where appropriate, other agency regulations. The NRC has adopted the following definition of the purpose and need of this Supplement:

> The purpose and need are to provide an analysis of environmental impacts from decommissioning activities that can be treated generically so that decommissioning activities for commercial nuclear power reactors conducted at specific sites will be bounded, to the extent practicable, by this and appropriate previously issued environmental impact statements.

This Supplement is intended to be used to evaluate environmental impacts during the decommissioning of nuclear power facilities as residual radioactivity at the site is reduced to levels that allow for termination of the NRC license. This Supplement can be considered a stand-alone document for power reactor facilities such that readers should not need to refer back to the 1988 GEIS. The environmental impacts described in this Supplement supercede those described in the 1988 GEIS for power reactor facilities.

The NRC elected to supplement the 1988 GEIS:

(1) to further the purposes of the National Environmental Policy Act (NEPA)

(2) to update the information in the 1988 GEIS

(3) to provide additional information to the public on decommissioning activities

(4) to establish an envelope of environmental impacts associated with decommissioning activities.

Unlike the 1988 GEIS, this Supplement covers only reactor facilities licensed by the NRC for commercial power production. It updates the sections of the 1988 GEIS relating to pressurized water reactors, boiling water reactors, and multiple reactor stations. It goes beyond the 1988 GEIS and considers the permanently shut down high-temperature gas-cooled reactors and fast

breeder reactors. It does not cover research and test reactors or power reactor facilities that have been involved in a significant accident resulting in large-scale contamination of structures, systems, and components (SSCs). It also does not cover other types of fuel-cycle facilities, such as fuel-reprocessing plants or small mixed oxide fuel-fabrication plants.

This Supplement incorporates updated information, regulations, and analyses. Since the 1988 GEIS was written, the NRC and the industry have gained over 200 facility-years' worth of additional decommissioning experience. Currently, there are 19 nuclear power reactor facilities in the decommissioning process. This includes nine that permanently ceased operations after the NRC published the 1988 GEIS. Since the 1988 GEIS, three facilities have completed decommissioning and terminated their licenses: Pathfinder, Shoreham, and Fort St. Vrain. This Supplement addresses new decommissioning technologies and approaches that the 1988 GEIS did not address. Also, the decommissioning regulations have changed since the 1988 GEIS.

1.2 Process Used to Determine Scope of This Supplement

The content of this Supplement was initially defined by the scope of the 1988 GEIS and was modified based on current decommissioning regulations, inputs from the scoping process and the outcome of meetings between the NRC, the U.S. Environmental Protection Agency (EPA), and the Council on Environmental Quality (CEQ).

Four public scoping meetings were held between April and June 2000 as part of the scoping process. During the meetings, the NRC outlined the GEIS revision process and accepted comments regarding the scope of this Supplement. In addition to comments obtained during the scoping meetings, the NRC received 12 letters from industry groups, other interested organizations, and private citizens. A total of 397 comments were provided during the scoping process. The staff reviewed the comments and categorized them as either relevant to this Supplement or outside of its intended scope. The staff prepared and issued a scoping summary report on April 17, 2001 (NRC 2001), that summarized the comments and NRC responses to the comments. Appendix N is an extraction of comments from the scoping summary report that were considered to be within the scope of the environmental review. The NRC staff published for comment draft Supplement 1 to the GEIS in October 2001. Public meetings in San Francisco, California, Boston, Massachusetts, Chicago, Illinois and Atlanta, Georgia, were held in December 2001, to describe the preliminary results of the NRC environmental review, to answer questions, and to provide members of the public with information to assist them in formatting comments on the draft Supplement. All comments received on the draft Supplement were considered by the staff in developing the final document. Appendix O provides a compilation of comments received on the draft Supplement and staff responses to the comments. Originally, the staff planned to publish the scoping

summary and the response to comments in Appendices A and B of this report. However, due to the length of these two appendices, the staff decided to publish these two appendices and the appendix containing the transcripts and comment letters in a second volume. In addition to the scoping meetings, meetings were held with EPA and CEQ between February and November 2000 to obtain input on the scope of the environmental review.

Site visits were conducted by the NRC staff and its contractor at six nuclear reactor facilities that are in various stages of decommissioning. The site visits were conducted to obtain information and to familiarize the NRC team with the current types of activities conducted and the resulting impacts during decommissioning. In addition to the site visits, the Nuclear Energy Institute arranged access to additional site-specific decommissioning data. In addition to the six sites visited, data was received for three other nuclear power reactor facilities.

Information used in this report was also obtained from docketed material, such as post-shutdown decommissioning activity reports (PSDARs), effluent release reports, license termination plans (LTPs), and decommissioning funding plans.

1.3 Scope of This Supplement

Except for decommissioning planning activities, this Supplement considers only activities that occur following certification that fuel has been removed from the reactor. Figure 1-1 illustrates the decommissioning process. Licensee decommissioning activities are listed in the top part of the timeline. Regulatory activities are summarized by the lower part of the timeline. This section discusses licensee decommissioning activities that are within scope and also explains why some activities and impacts are not in scope for this Supplement. Table 1-1 briefly lists decommissioning activities that are within and outside the scope of this Supplement. Additional discussion of the out-of-scope activities is provided in Appendix D.

Impacts related to the decision to permanently cease operations are outside the scope of this Supplement. This includes impacts that result directly and immediately from the act of permanently ceasing operations, regardless of when or why the decision was made. For example, when a reactor ceases operation, the flow of warmer water into the canal, lake, or river that receives the plant's thermal discharges is stopped, and this may impact the organisms in the vicinity of the thermal outfall. However, this impact is not within the scope of this Supplement because it is essentially a restoration of the existing conditions.

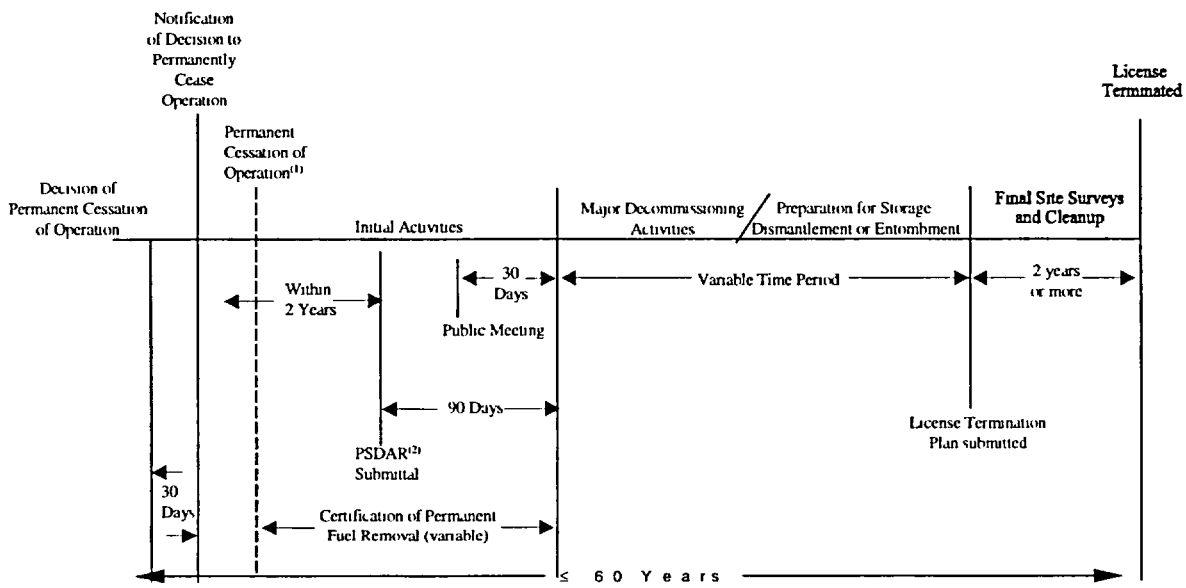

Figure 1-1.
Decommissioning Timeline

(1) The cessation of operations may occur before, concurrent with, or following the certification to permanently cease operations.
(2) The PSDAR may be submitted before permanent cessation of operations.

The licensee may declare or certify the date for permanent cessation of operations prior to the end of the license term and while still operating. In such cases, the decommissioning planning activities prior to shutdown and activities and impacts that occur following the actual shutdown of the facility are within the scope of this Supplement. In some circumstances, the licensee may not operate the facility for a period of many years without certifying that they have permanently ceased power operations. In these cases, the activities occurring before the certification is completed would be considered part of the operational phase of the facility and would be within the scope of the site-specific environmental impact statement (EIS) that covers reactor operations but are outside the scope of this Supplement.

The NRC definition for *decommission* in 10 CFR 50.2 is "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." This Supplement is not limited only to activities directly related to the removal of radioactive material from facilities or that must be performed to facilitate removal of contaminated SSCs. The staff has included activities and impacts related

to removing uncontaminated SSCs that were required for reactor operation, such as the intake structure or cooling towers. Including uncontaminated SSCs in this Supplement is consistent with an expectation under NEPA that all impacts associated with an activity and that public concerns about the scope of the review be considered.

Various activities that are performed in conjunction with decommissioning are not considered within the scope of this Supplement, but are reviewed and regulated by the NRC under other licenses. These activities include

- independent spent fuel storage installation (ISFSI) construction, maintenance, and decommissioning – An ISFSI can be operated and decommissioned either under the same license that is used for the operating or decommissioning facility called a general license under 10 CFR Part 50, or under a specific license under 10 CFR Part 72. If a licensee chose to operate the ISFSI under a Part 50 license, it could choose to continue to maintain their Part 50 license, or seek a site -specific 10 CFR Part 72 license for the ISFSI, thus allowing termination of the Part 50 license and the end of the reactor decommissioning process. The NRC staff would also be required to conduct an environmental assessment of the licensee's request for a site-specific 10 CFR Part 72 license.

- spent fuel storage and maintenance – The Commission has independently, in a separate proceeding (the Waste Confidence Proceeding), made a finding that there is

  > reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations. (54 FR 39767)

The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at that time (64 FR 68005). Accordingly, the Commission reaffirmed its findings of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The staff relies on the Waste Confidence Rule, but has elected to include in this Supplement information related to the storage and maintenance of fuel in a spent fuel pool for completeness.

Table 1-1. Activities and Impacts Within or Outside the Scope of This Supplement

In Scope
• Activities performed to remove the facility from service from the time that the licensee certifies that the facility has permanently ceased operations
• Activities (and the resulting impacts) performed in support of radiological decommissioning, including decontamination and dismantlement of radioactive structures and any activities required to support the decontamination and dismantlement process
• Activities performed in support of dismantlement of nonradiological structures, systems, and components (SSCs) required for the operation of the reactor, such as diesel generator buildings and cooling towers
• Activities performed up to license termination and their resulting impacts as provided in the definition of decommissioning Nonradiological impacts occurring after license termination from activities conducted during decommissioning
• Activities related to release of the facility
• Human health impacts from radiological and nonradiological decommissioning activities
• Activities related to preparing the facility for entombment
Out of Scope[a]
• Activities and the resulting impacts (other than planning activities) that are performed before permanent cessation of operation is certified
• Radiological impacts following license termination
• Activities (and the resulting impacts) performed to dismantle structures on the site that are not radiologically contaminated and were not required for operation of the reactor (e.g., training building and administration building)
• Activities performed to support installation of alternate energy-generating facilities during or following the decommissioning process
• Site restoration activities performed during or after the decommissioning process
• Activities (and their impacts) performed after license termination, such as - any additional non-NRC required monitoring to evaluate radiological impacts - site restoration - continued use of site for power production or other activities
• Activities performed at facilities that are separately licensed or regulated - independent spent fuel storage installation (ISFSI) construction, maintenance, or decommissioning - interim storage of Greater-than-Class-C Waste - spent fuel storage,[b] maintenance, and disposal on or away from a reactor location - low-level waste (LLW) disposal at a licensed LLW site or treatment at compactor facilities
• Activities to install engineered barriers and institutional controls for restricted release
• Public perceptions and psychological impacts
• Activities at facilities that have been permanently shut down by a major accident
• Issues related to the ENTOMB option after the facility begins the entombment period

(a) A detailed discussion of the reasons for determining that activities are out of scope can be found in Appendix D.
(b) As discussed in the text, the staff relies on the Waste Confidence Decision Review (54 FR 39767 and 64 FR 68005) but has chosen to include information related to the storage and maintenance of fuel in a spent fuel pool for completeness in this Supplement.

- spent fuel transport and disposal away from the reactor location – Transportation of spent fuel and other high-level nuclear wastes is governed by regulations in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material." Disposal of spent fuel and high-level wastes are governed by the Nuclear Waste Policy Act (NWPA) of 1982, as amended, which defined the goals and structure of a program for permanent, deep geologic repositories for the disposal of high-level radioactive waste and nonreprocessed spent fuel. Under this Act, the U.S. Department of Energy (DOE) is responsible for developing permanent disposal capacity for spent fuel and other high-level nuclear wastes. Title 10 CFR Part 60 contains rules governing the licensing to receive and possess source, special nuclear, and by-product material at a geological repository operations area that is sited, constructed, or operated in accordance with the NWPA. However, the Commission issued the final rule to supercede the generic criteria in 10 CFR Part 60 for disposal at a geological repository with specific criteria in 10 CFR Part 63, issued on November 2, 2001 (66 FR 55732).

- LLW disposal at a licensed LLW site or treatment of LLW at compactor facilities – Regulations related to LLW disposal are in 10 CFR Part 61 and 10 CFR Part 20, Subpart K. A final GEIS supporting the regulations in 10 CFR Part 61, "Final Generic Environmental Impact Statement for 10 CFR Part 61" was published as NUREG-0945 (NRC 1982).

A further description of these activities and the basis for not including them in the scope of this supplement is in Appendix D.

The decommissioning process continues until the licensee requests termination of the license and demonstrates that radioactive material has been removed to levels that permit termination of the NRC license. Once the NRC determines that the decommissioning is completed, the license is terminated. At that point, the NRC no longer has regulatory authority over the site, and the owner of the site is no longer subject to NRC regulations. As a result, activities performed after license termination and the resulting impacts are outside the scope of this Supplement. These activities may include any non-NRC required monitoring, site restoration (grading, planting of vegetation, etc.), continued dismantlement or continued use of the site for activities such as power production using natural gas, oil, or coal.

Any potential radiological impacts following license termination that are related to activities performed during decommissioning are not considered in this Supplement. Such impacts are covered by the Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities, NUREG-1496 (NRC 1997).

Any potential nonradiological impacts resulting from decommissioning and occurring after termination of the license are considered within the scope of this Supplement. Onsite disposal has been proposed by the industry as a method to dispose of slightly radiologically contaminated building rubble provided that the waste is buried onsite below grade, for example, in existing underground portions of the dismantled plant in such a manner as to meet the site release criteria of 10 CFR Part 20, Subpart E. This concept has been referred to as "Rubblization" (the disposal onsite of slightly contaminated material in a manner to meet the 10 CFR Part 20 release criteria).[(a)] On February 14, 2000, the staff informed the Commission of licensee interest in this method and the staff's intent to address Rubblization in this Supplement (NRC 2000). The staff has determined that the long-term radiological aspects of Rubblization, or onsite disposal of slightly contaminated material, would require a site-specific analysis and would be addressed at the time the LTP is submitted. The nonradiological impacts, occurring both during the decommissioning period (e.g., noise, dust, land disturbance), and the long-term impacts occurring after the decommissioning activities are completed (e.g., concrete leaching into the groundwater) can be evaluated generically and are included in the evaluation of each of the applicable environmental issues in Chapter 4 of this document.

Public perceptions and psychological impacts related to the risk of a radiological accident during decommissioning are not addressed in the 1988 GEIS and are not addressed in this Supplement. The U.S. Supreme Court stated in *Metropolitan Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, at 774-775, that such psychological effects or impacts raised policy questions that fell outside of NEPA. This court case involved an organization of residents living in the area of Three Mile Island, People Against Nuclear Energy (PANE), that claimed the NRC should consider, as part of an EIS, the severe psychological stress caused to its members by the restart of Three Mile Island, Unit 1, after the accident at Three Mile Island, Unit 2. However, in *Metropolitan Edison Co., et al. v. People Against Nuclear Energy* (1983), the Supreme Court read NEPA to require

> a reasonably close causal relationship between a change in the physical environment and the effect at issue .... a risk of an accident is not an effect on the physical environment .... We believe that the element of risk lengthens the causal chain beyond the reach of NEPA.

(a) The term "rubblization" is frequently used to describe the crushing of structural material (e g., concrete) to facilitate disposal. The material may be concrete that is uncontaminated or contaminated with radiological material. The staff used the term Rubblization to describe the process of onsite disposal of slightly contaminated material in a manner to meet the site release criteria. For this report, in order to avoid confusion, the staff chose to use the term "demolition" instead of rubblization as the verb to describe the process of crushing structural material to allow for easy burial or disposal.

The decommissioning activities following shutdown of a facility after a major accident resulting in significant contamination of the site are outside the scope of this Supplement. For most types of accidents, decommissioning would be treated on a site-specific basis and, therefore, cannot be considered in a generic sense.

1.4 Categories for Environmental Impacts and Extent of Issues

In the analysis of potential issues in decommissioning activities, two areas in particular were found to benefit from categorization: (a) ranking the significance and severity of potential environmental impacts for proposed decommissioning activities and (b) sorting potential issues as either generic or site-specific.

1.4.1 Levels of Significance of Environmental Impacts

For decommissioning, the staff is using a standard of significance derived from the CEQ terminology for "significantly" (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

SMALL – Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

MODERATE – Environmental impacts are sufficient to alter noticeably, but not to destabilize, important attributes of the resource.

LARGE – Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the NRC staff assumed that ongoing mitigation measures would continue (including those mitigation measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

1.4.2 Regulatory Distinction of Generic and Site-Specific Approaches

In addition to determining the significance of environmental impacts, this Supplement includes a determination of whether the analysis of the environmental issue could be applied to all plants, and whether additional mitigation measures would be warranted. An environmental issue may be assigned to one of two categories (generic or site-specific) described below.

- Generic – For each environmental issue, the analysis reported in this Supplement shows the following:

  (1) Environmental impacts associated with the issue have been determined to apply either to all plants, or for some issues to plants having a specific size, specific location, or having a specific type of cooling system or other site characteristics, and

  (2) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

  (3) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are not likely to be sufficiently beneficial to warrant implementation.

- Site-specific – For each environmental issue that was determined to be site-specific, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required.

1.5 Uses of This Supplement

This Supplement can be used by the public to understand the decommissioning process, the activities performed during decommissioning, and the potential environmental impacts resulting from these activities. The Supplement does not (1) establish or revise regulations, (2) impose requirements, (3) provide relief from requirements, or (4) provide guidance on the decommissioning process.

This Supplement identifies activities that can be bounded by a generic evaluation. It also identifies the decommissioning activities and associated environmental issues that will likely require site-specific analysis before performing a decommissioning activity.

Licensees can rely on the information in this Supplement as a basis for meeting the requirements in 10 CFR 50.82(a)(6)(ii). This requirement states that the licensee must not perform any decommissioning activity that causes any significant environmental impact not previously

reviewed. Prior to conducting a decommissioning activity, the licensee must make a determination that the resulting environmental impacts fall within the bounds of this Supplement or of another EIS related to its facility. When finalized, licensees are expected to reflect the environmental impacts described in this Supplement rather than those in the 1988 GEIS. For any decommissioning activity that does not meet these conditions, the regulations prohibit the licensee from undertaking the activity until it performs a site-specific analysis of the activity. Depending on the results of the site-specific evaluation, the staff may determine that it is appropriate to consult with another agency about the potential impacts. Such agencies could include the U.S. Fish and Wildlife Service or a State Historic Preservation Office. If the activity would result in an impact that is outside the bounds of the GEIS or other environmental assessments, the licensee would be required to submit a license-amendment request. The NRC staff periodically inspects the licensee's procedures and documentation to ensure that a proper environmental review is part of the screening criteria used for proposed changes to the facility.

In addition to the NRC staff's review of the licensee's procedures and documentation, there are two points during the decommissioning process when the licensee performs an evaluation of environmental impacts. The first evaluation occurs when the licensee must submit a PSDAR to the NRC (within two years following permanent cessation of operation). The PSDAR must include a discussion that provides the reasons for concluding that the environmental impacts associated with the licensee's planned site-specific decommissioning activities will be bounded by an appropriate previously issued environmental assessments, including this Supplement. If the licensee identifies environmental impacts that are not bounded by a previous NRC environmental assessment, the licensee must address the impacts in a request for a license amendment regarding the activities. The licensee must also submit a supplement to its environmental report (ER) that describes and evaluates the additional impacts. The NRC will review the supplement to the ER in conjunction with its review of the license-amendment request.

The second evaluation is near the end of decommissioning at the time when the licensee submits an application for license termination. In accordance with 10 CFR 50.82(a)(9), a licensee must submit its LTP at least 2 years before the anticipated termination date of the license. The LTP must be a supplement to the Final Safety Analysis Report or its equivalent for the facility and is submitted as a license amendment. The NRC requires an environmental review as part of the review of the license-amendment request. Thus, the LTP must include a supplement to the ER that describes any new information or significant environmental change associated with the licensee's proposed termination activities. The NRC staff will also rely upon this supplement as a basis for determining if anticipated decommissioning impacts require an additional review.

1.6 Development of This Supplement

The requirements in 10 CFR Part 51 were followed for the development of this Supplement. This included conducting scoping meetings and obtaining public comments (see Appendix N). From these meetings and meetings with other appropriate government agencies, the staff defined the scope of this Supplement (see Sections 1.2 and 1.3). During the scoping process, the staff developed an evaluation process for determining the environmental impacts from decommissioning. Section 4.2 provides additional discussion of the process and Appendix E provides a detailed description of the analysis used to identify the environmental impacts from decommissioning. The evaluation process involved determining the specific activities that occur during decommissioning and obtaining data from site visits and from an information request to decommissioning plants that was related to the impact of these activities at currently decommissioning facilities. The data obtained from the decommissioning sites were analyzed and then evaluated against a list of variables that defined the parameters for plants that are currently operating but which will one day be decommissioned. This evaluation resulted in a range of impacts for each environmental issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

1.7 Parts of This Supplement

Chapter 2 provides background, describing the basis for the current regulations and summarizing the regulations. Chapter 3 describes the types of plants covered by this Supplement, which includes permanently shutdown reactor facilities as well as operating facilities that will eventually cease power operations. Chapter 3 also describes the location and types of buildings on the sites, the systems that may still be active after permanent shutdown, and changes in effluents after permanent shutdown. Chapter 4 describes activities conducted during the decommissioning process and impacts that could arise from these activities. The analysis of the impacts is based on variables such as the option of decommissioning, location of plant, type of plant, and timing of the activity. Chapter 5 discusses the "No Action" alternative to decommissioning, which is the abandonment of the facility after the cessation of operations. Chapter 6 contains the summary of findings and conclusions.

1.8 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 60. Code of Federal Regulations, Title 10, *Energy*, Part 60, "Disposal of high-level radioactive wastes in geologic repositories."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste.

10 CFR 63. Code of Federal Regulations, Title 10, *Energy*, Part 63, "Disposal of high-level radioactive wastes in a geologic repository at Yucca Mountain, Nevada."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and transportation of radioactive material."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel, high-level radioactive waste, and reactor-related greater-than-Class-C waste."

40 CFR 1508. Code of Federal Regulations, Title 40, *Protection of the Environment*, Part 1508, "Terminology and Index."

54 FR 39767. "10 CFR Part 51 Waste Confidence Decision Review." *Federal Register*. September 28, 1989.

64 FR 68005. "Waste Confidence Decision Review." *Federal Register*. December 6, 1999.

66 FR 55732. "Disposal of High-Level Radioactive Wastes in a Proposed Geologic Repository at Yucca Mountain, Nevada." *Federal Register*. November 2, 2001.

Metropolitan Edison Co., et al v. People Against Nuclear Energy, 460 U.S. 766, at 774-775. 1983.

National Environmental Policy Act (NEPA) of 1969, as amended, 42 USC 4321 et seq.

Nuclear Waste Policy Act of 1982, as amended, 42 USC 10.101 et seq.

U.S. Nuclear Regulatory Commission (NRC). 1982. *Final Generic Environmental Impact Statement for 10 CFR Part 61*. NUREG-0945, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities.* NUREG-0586, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997. *Final Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities.* NUREG-1496, Vol. 1, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2000. "SECY-00-0041 Use of Rubblized Concrete Dismantlement to Address 10 CFR Part 20, Subpart E, Radiological Criteria for License Termination." NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 2001. Letter from U.S. NRC to Distribution: "Subject: Issuance of a scoping summary report of comments received related to the intent to develop a Supplement to NUREG-0586." Dated April 17, 2001.

2.0 Background Information Related to Decommissioning Regulations

This section provides background information that will assist the reader in understanding the requirements for decommissioning and license termination. The basis for the current decommissioning regulations and a summary of the current regulations are provided below. This chapter and Chapter 3, "Description of NRC Licensed Reactor Facilities and the Decommissioning Process," will give the reader a basic understanding of the overall reactor decommissioning process and environmental impact assessments used during the process.

2.1 Basis for Current Regulations

In the mid-1990s, the Commission initiated an effort to significantly change the regulations for decommissioning power reactor facilities. The new regulations were intended to make the decommissioning process more current, efficient, and uniform. On July 29, 1996, a final rule revising 10 CFR 50.82, "Decommissioning of Nuclear Power Reactors," was published in the Federal Register (61 FR 39278). This rule redefined the decommissioning process and modified the regulations written in 1988, which had required submittal of a detailed decommissioning plan before the start of decommissioning.

The regulations were revised based on experience gained from reactor decommissionings that had occurred during the 1980s and early 1990s. Review of the activities that occur during decommissioning showed that they are similar to the activities that occur during the construction, operation, maintenance, and refueling outages of a power reactor (e.g., decontamination, steam generator replacement, and pipe removal). However, the magnitude of some activities during decommissioning (e.g., removal of piping) is considerably greater than during operations. Activities associated with the decommissioning of facilities had resulted in impacts consistent with or less than those evaluated in the 1988 *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (GEIS), NUREG-0586 (NRC 1988). Based on the above reasons, the Commission determined that review and approval by the U.S. Nuclear Regulatory Commission (NRC) staff of a detailed decommissioning plan was not necessary.

2.2 Summary of Current Regulations

2.2.1 Regulations for Decommissioning Activities

The current regulations (10 CFR 50.82) specify the regulatory actions that both the NRC and the licensee must take to decommission a nuclear power facility. Once the licensee decides to permanently cease operations, it must submit, within 30 days, a written certification to the NRC.

The notification must contain the date on which the power-generating operations ceased or will cease. The licensee must permanently remove all fuel from the reactor and submit a written certification to the NRC confirming the completion of fuel removal. Once this certification has been submitted, the licensee is no longer permitted to operate the reactor, or to put fuel back into the reactor vessel. After certification that the fuel is removed, the annual license fee to the NRC is reduced as well as the licensee's obligation to adhere to certain requirements that are needed only during reactor operations.

In addition to the certifications, the licensee must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC and any affected States no later than 2 years after the date of permanent cessation of operations. Section 10 CFR 50.82 requires that the PSDAR include

- a description of the licensee's planned major decommissioning activities
- a schedule for completing these activities
- an estimate of the expected decommissioning costs
- a discussion that provides the reasons for concluding that the environmental impacts associated with site-specific decommissioning activities will be bounded by an appropriate previously issued environmental impact statement (EIS).

After receiving a PSDAR, the NRC publishes a notice of receipt in the Federal Register, makes the PSDAR available for public review and comment, and holds a public meeting in the vicinity of the facility to discuss the licensee's plans. The NRC will examine the PSDAR to determine if the required information is included and will inform the licensee in writing if there are deficiencies that must be addressed before the licensee initiates any major decommissioning activities. The regulations require a 90-day waiting period after submittal of the PSDAR before the licensee may commence major decommissioning activities.

The purpose of the PSDAR is to provide the NRC and the public with a general overview of the licensee's proposed decommissioning activities. The PSDAR serves to inform the NRC staff of the licensee's expected activities and schedule, which facilitates planning for inspections and decisions regarding NRC oversight activities. The PSDAR is also a mechanism for informing the public of the proposed decommissioning activities before those activities are conducted.

Prior to submission of the PSDAR, the licensee can conduct a variety of activities at the site including activities to ensure the safe shutdown of the facility. Systems can be drained, components removed, and certain structures demolished. However, the licensee is prohibited from undertaking any major decommissioning activity as defined in 10 CFR 50.2.

Once the PSDAR has been submitted and the 90-day period has been completed, the licensee may begin major decommissioning activities, which may include the following:

- permanent removal of major radioactive components, such as the reactor vessel, steam generators, or other components that are comparably radioactive
- permanent changes to the containment structure
- dismantling of components containing Greater-than-Class-C (GTCC) Waste.[a]

In accordance with 10 CFR 50.82(a)(6)(ii), licensees shall not perform any decommissioning activities "that result in significant environmental impacts not previously reviewed." If any decommissioning activity does not meet this requirement, the licensee must submit a license-amendment request before conducting the activity. The licensee also must submit a supplement to its environmental report (ER) that relates to the additional impacts. The NRC will review the ER Supplement, and prepare an environmental assessment (EA) or EIS, and amendment to the license in conjunction with its review.

The licensee can choose (1) to immediately decontaminate and dismantle the facility (DECON), or (2) to place the facility in long-term storage (SAFSTOR) followed by subsequent decontamination and dismantlement, or (3) to perform some incremental decontamination and dismantlement activities before or during the storage period of SAFSTOR. Under the current regulations, unless the licensee receives permission to the contrary, the site must be decommissioned within 60 years. Chapter 3 describes in more detail the decommissioning

(a) The NRC has adopted a waste classification system for low-level radioactive waste based on its potential hazards, and has specified disposal and waste form requirements for each of the general classes of waste: A, B, and C. The classifications are based on the key radionuclides present in the waste and their half-lives. Tables defining these three classes are contained in 10 CFR 61.55. In general, requirements for waste form, stability, and disposal methods become more stringent when going from Class A to Class C. GTCC waste exceeds the concentration limits in 10 CFR 61.55 and is generally unsuitable for near-surface disposal as low-level waste (LLW), even though it is legally defined as LLW. The NRC's regulations in 10 CFR 61.55(a)(2)(iv) require that this type of waste must be disposed of in a geologic repository unless approved for an alternative disposal method on a case-specific basis by the NRC. 10 CFR Part 72 allows for interim storage of GTCC from a commercial power reactor.

options available to the licensee. In this Supplement, the staff also evaluates another option called ENTOMB, which encases the radioactive contaminants in a structurally long-lived material.

2.2.2 Regulations for License Termination

In order to terminate the license and allow release of the site, the licensee must submit a license termination plan (LTP). In accordance with 10 CFR 50.82(a)(9), an application for license termination must be accompanied or preceded by an LTP, which is subject to NRC review and approval. The licensee must submit the LTP at least 2 years before the date of license termination. The LTP approval process is by license amendment. By regulation, the LTP must include the following:

- a site characterization
- identification of remaining dismantlement activities
- plans for site remediation
- detailed plans for the final survey of residual contamination
- a description of the end-use of the site (if restricted use is proposed)
- an updated site-specific estimate of remaining decommissioning costs
- a supplement to the ER.

The licensee must submit the LTP as a supplement to its Final Safety Analysis Report or as an equivalent document, thus formalizing the steps necessary to revise the document.

After receiving the LTP, the NRC will place a notice of receipt of the plan in the Federal Register and will make the plan available to the public for comment. The NRC will schedule a public meeting near the facility to discuss the plan's contents and the staff's process for reviewing the submittal. The NRC will also offer an opportunity for a public hearing on the license-amendment request associated with the LTP. At this stage, a site-specific EA is required. Depending on the circumstances, the EA evaluation can result in the development of a full EIS. If the LTP demonstrates that the remainder of decommissioning activities will be performed in accordance with NRC regulations, are not detrimental to the health and safety of the public, and will not have a significant adverse effect on the quality of the environment, the

Commission will approve the plan by a license amendment (subject to whatever conditions and limitations the Commission deems appropriate and necessary).

After the approval of the LTP, the NRC will continue its inspection of the site. These inspections will include validation of commitments made in the LTP. Inspections may also include confirmatory surveys to verify that areas of the site have been decontaminated to the limits established in the LTP.

On July 21, 1997, the NRC published (also in the Federal Register) a final rule entitled, "Radiological Criteria for License Termination" (64 FR 39058) prescribing specific radiological criteria for license termination. At the end of the LTP process, if the NRC determines that the remaining dismantlement has been performed in accordance with the approved LTP, and if the final radiation survey and associated documentation demonstrate that the facility and site are suitable for release, then the Commission will terminate the license.

The radiological criteria for license termination are given in 10 CFR Part 20, Subpart E. There are two broad categories of uses for the facility after the license termination: unrestricted use and restricted use.

Unrestricted use means that there are no NRC-imposed restrictions on how the site may be used. State and local jurisdictions may, and have, imposed additional restrictions or requirements on licensees. The licensee is free to continue to dismantle any remaining buildings or structures and to use or sell the land for any type of application. The Commission has established a 0.25 mSv/yr (25 mrem/yr) total effective dose equivalent (TEDE) to an average member of the critical group[a] as an acceptable criterion for release of any site for unrestricted

(a) The "critical group" is that group of individuals reasonably expected to receive the highest exposure to residual radioactivity within the assumptions of a particular scenario. The average dose to a member of the critical group is represented by the average of the doses for all members of the critical group, which in turn is assumed to represent the most likely exposure situation. For example, when considering whether it is appropriate to "release" a building that has been decontaminated (allow people to work in the building without restrictions), the critical group would be the group of employees that would regularly work in the building. If radiation in the soil is the concern, then the scenario used to represent the maximally exposed individual is that of a resident farmer. The assumptions used for this scenario are prudently conservative and tend to overestimate the potential doses. The added "sensitivity" of certain members of the population, such as pregnant women, infants, children, and any others who may be at higher risk from radiation exposures, are accounted for in the analysis. However, the most sensitive member may not always be the member of the population that receives the highest dose. This is especially true if the most sensitive member (e.g., an infant) does not participate in activities that provide the greatest dose or if they do not eat specific foods that cause the greatest dose.

use. The licensee will be required to show that the site can meet this criterion before the license will be terminated for unrestricted use. In addition, the licensee will need to show that the amounts of residual radioactivity have been reduced to levels that are as low as reasonably achievable (ALARA).[(a)] For sites that have been determined to be acceptable for unrestricted use, there are no requirements for further measurement of radiation levels. It is not expected that these radiation levels would change (other than to be reduced over time through radioactive decay), and there would be no mechanism for further contamination or radiological releases.

Restricted use means that there are restrictions on the facility use after license termination. A site would be considered acceptable for license termination under restricted conditions if the licensee can demonstrate that further reductions in residual radioactivity necessary to meet the requirements for unrestricted use would result in net public or environmental harm, or were not being made because the residual levels were ALARA. In addition, the licensee must have made provisions for legally enforceable institutional controls (e.g., use restrictions placed in the deed for the property) that provide reasonable assurance that the radiological criteria set by the NRC (0.25 mSv/yr [25 mrem/yr] TEDE to an average member of the critical group) will not be exceeded. The licensee must also have provided sufficient financial assurance to an amenable independent third party to assume and carry out responsibilities for any necessary control and maintenance of the site. There are also regulations relating to the documentation of how the advice of individuals and institutions in the community who may be affected by decommissioning has been sought and incorporated in the LTP if the license is to be terminated under restricted conditions.

Residual radioactivity at the site must be reduced so that if the institutional controls were no longer in effect, there would be reasonable assurance that the TEDE from residual radioactivity distinguishable from background to the average member of the critical group would be ALARA and would not exceed either 1 mSv/yr (100 mrem/yr) or 5 mSv/yr (500 mrem/yr). In the latter case, the licensee must (1) demonstrate that further reductions in residual radioactivity necessary to comply with the 1 mSv/yr (100 mrem/yr) value are not technically achievable, would be prohibitively expensive, or would result in net public or environmental harm, (2) make provisions for durable institutional controls, and (3) provide sufficient financial assurance to enable a responsible government entity or independent third party to carry out periodic checks of the facility no less frequently than every 5 years to ensure that the institutional controls remain in place.

(a) The ALARA concept means that all doses are to be reduced below required levels to the lowest reasonably achievable level considering economic and societal factors. Determination of levels that are ALARA must consider any detriments, such as deaths from transportation accidents, that are expected to potentially result from disposal of radioactive waste.

Alternate release criteria may be used in specific cases. The use of alternate criteria to terminate a license requires the approval of the Commission after consideration of the NRC staff's recommendations that address comments provided by the U.S. Environmental Protection Agency and any public comments submitted pursuant to 10 CFR 20.1405. These alternate criteria are expected to be used only in very rare cases.

To date, the three NRC-licensed facilities (Shoreham, Fort St. Vrain, and Pathfinder) that have completed the decommissioning process have had their licenses terminated, allowing unrestricted use of the sites. License termination plans have been submitted for three other facilities. The LTPs describe plans for unrestricted use of the sites following license termination. No nuclear power licensees have indicated that they plan for restricted use of the site after license termination.

A proposed rule was issued on September 4, 2001 (66 FR 46230) for partial site release prior to license termination. Partial site release means release of part of a nuclear power reactor facility or site for unrestricted use prior to NRC approval of the LTP. The NRC proposes to add a new section to 10 CFR Part 50, separate from the existing rules for decommissioning and radiological criteria for license termination, that identifies the requirements and criteria necessary for partial site release. The proposed rule includes associated amendments to 10 CFR Part 2 and 10 CFR Part 20. The purpose of this rulemaking is to ensure that any remaining residual radioactive material from licensed activities on a portion the site released for unrestricted use will meet the radiological criteria for license termination.

Licensees will be required to submit information necessary to demonstrate the following:

- The release of radiologically impacted property complies with the radiological criteria for unrestricted use in 10 CFR 20.1402 (0.25 mSv/yr [25 mrem/yr] to the average member of the critical group and ALARA).

- The licensee will continue to comply with all other applicable regulatory requirements that may be affected by the release of property and changes to the site boundary. This would include, for example, requirements in 10 CFR Parts 20, 50, 72, and 100.

- Records of property-line changes and the radiological conditions of partial site releases are being maintained to ensure that the dose from residual material associated with these releases can be accounted for at the time of any subsequent partial releases and at the time of license termination.

The proposed rule provides additional flexibility to licensees who are releasing property that has never been radiologically impacted. While an amendment of the Part 50 operating license is required to release radiologically impacted property, the proposed rule offers the opportunity for a letter submittal for partial releases if the licensee can demonstrate that there is no reasonable potential for residual radioactivity from license activities.

2.3 References

10 CFR 2. Code of Federal Regulations, Title 10, *Energy*, Part 2, "Rules of practice for domestic licensing proceedings and issuance of orders."

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel high-level radioactive waste and reactor-related greater-than-Class-C waste."

10 CFR 100. Code of Federal Regulations, Title 10, *Energy*, Part 100, "Reactor site criteria."

61 FR 39278. "Decommissioning of Nuclear Power Reactors. Final Rule." *Federal Register*. July 29, 1996.

64 FR 39058. "Radiological Criteria for License Termination. Final Rule." *Federal Register*. July 21, 1997.

66 FR 46230. "Releasing Part of a Power Reactor Site or Facility for Unrestricted Use Before the NRC Approves the License Termination Plan. Proposed Rule." *Federal Register*. September 4, 2001.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*. NUREG-0586, NRC, Washington, D.C.

3.0 Description of NRC Licensed Reactor Facilities and the Decommissioning Process

This chapter provides information on both the operating nuclear power plants and those being decommissioned. First, a general description of the nuclear power plants and sites is provided in Section 3.1 to help the reader understand the types of reactor facilities that will be decommissioned, the location of the radioactive material in these facilities, and the structures, systems, and components (SSCs) that will be referred to later in this document and that are important in the decommissioning process. Next, the methods that are commonly used during decommissioning are described in Section 3.2. Section 3.3 addresses the decommissioning experience of the currently decommissioning plant sites, their chosen method for decommissioning, and the activities that are being used to decommission the facilities.

There are currently 22 nuclear power reactors at 21 sites that are permanently shut down: 19 of these reactors are in various stages of decommissioning, and reactors at 3 sites have finished decommissioning and no longer maintain a license. The decommissioning efforts at these 22 plants equates to over 200 equivalent years of experience decommissioning commercial power reactors since the 1988 *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities*, NUREG-0586 (1988 GEIS; NRC 1988) was published. There are also currently 104 nuclear plants that have a license and are either operating or have not yet certified that they have permanently ceased power operations. Between 2006 and 2035, these 104 plants will either permanently cease operations or renew their licenses. Ultimately, they will all permanently cease operations and be decommissioned.

3.1 Plants, Sites, and Reactor Systems[(a)]

Between 1957 and 1996, the U.S. Nuclear Regulatory Commission (NRC) issued 126 operating licenses for commercial power reactor operation at 80 sites. The history of and experience with the 22 reactors that are being decommissioned currently or have completed decommissioning are addressed in Section 3.3. Because each of the remaining 104 operating plants will eventually enter the decommissioning process, their attributes and characteristics are included in this section to ensure that this Supplement is appropriate for future decommissioning plants. The material presented in this section is also provided as background information for the reader.

(a) Much of the information in this section was taken from NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NRC 1996) and from NUREG-1628, *Staff Responses to Frequently Asked Questions Concerning Decommissioning of Nuclear Power Reactors* (NRC 2000a). This information has been supplemented and updated as appropriate to include all operating and currently decommissioning nuclear plants.

Nuclear power reactor facilities are located in 35 of the contiguous States, with none in Alaska or Hawaii. Thirty-nine sites contain two or three nuclear power reactors (units) per site. Of the 126 plants, 98 are located east of the Mississippi River with most of the nuclear capacity located in the northeast (New England States, New York, and Pennsylvania), the midwest (Illinois, Michigan, and Wisconsin) and the southeast (Virginia, North and South Carolina, Georgia, Florida, and Alabama).

Typically, nuclear power plants are sited in flat or rolling countryside, in wooded or agricultural areas away from urban areas. Most are located on or near rivers or lakes. Several plants are located in arid regions, and 19 plants are located along the seacoast on bays or inlets. More than 50 percent of the sites have 80-km (50-mile) population densities of less than 77 persons/km^2 (200 persons/mi^2) and over 80 percent have 80-km (50-mile) densities of less than 193 persons/km^2 (500 persons/mi^2). The most notable exception is the Indian Point Station, located within 80 km (50 mi) of New York City, which has a projected 1999 population density within 80 km (50 mi) of more than 770 persons/km^2 (2000 persons/mi^2). Indian Point has one permanently shutdown reactor and two operating reactors.

Site areas range from a minimum of 34 ha (84 ac) for the San Onofre Nuclear Generating Station, (a three unit site, with one permanently shutdown reactor) in California to 9700 ha (24,000 ac) for the Turkey Point Plant in Florida (two operating units). Almost 60 percent of plant sites cover from 200 to 800 ha (500 to 2000 ac). Larger land-use areas are associated with plant cooling systems that include reservoirs, artificial lakes, and buffer areas.

Appendix F contains summary tables for both permanently shutdown and currently operating nuclear power facilities showing location, reactor type, thermal power, site area, cooling system and cooling water source, and licensing dates.

3.1.1 Types of Nuclear Power Reactor Facilities

In the United States, nearly all reactors used for commercial power generation have been conventional (thermal) light water reactors (LWRs) that use water as a moderator and coolant. The two types of LWRs are pressurized water reactors (PWRs) and boiling water reactors (BWRs). Of the 123 LWRs, 80 are PWRs and 43 are BWRs. The three plants that are not LWRs are Fermi, Unit 1, which is a permanently shutdown fast breeder reactor (FBR), and Peach Bottom, Unit 1, and Fort St. Vrain, which are permanently shutdown high-temperature gas-cooled reactors (HTGRs). Fermi, Unit 1, is currently performing the decontamination and

dismantlement phase of SAFSTOR (see Section 3.2). Peach Bottom, Unit 1, is in long-term storage. Fort St. Vrain has had its license terminated following completion of decommissioning activities.

Brief descriptions of these different types of reactors are given below as background.

3.1.1.1 Pressurized Water Reactors

In PWRs, water is heated to a high temperature under pressure inside the reactor. The water is then pumped in the primary circulation loop to the steam generator. Within the steam generator, water in the secondary circulation loop is converted to steam that drives the turbines. The turbines turn the generator to produce electricity. The steam leaving the turbines is condensed by water in the tertiary loop and returned to the steam generator. The tertiary loop water flows either to cooling towers, where it is cooled by evaporation or discharged to a body of water such as a river, lake, or other heat sink. The tertiary loop is open to the atmosphere, but the primary and secondary cooling loops are not (see Figure 3-1).

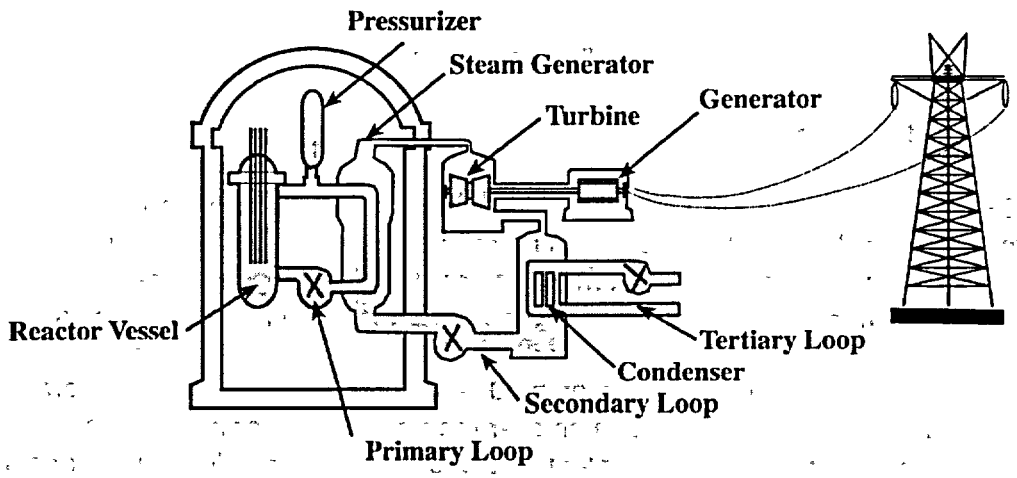

Figure 3-1. Pressurized Water Reactor

3.1.1.2 Boiling Water Reactors

The BWRs generate steam directly within the reactor vessel. The steam passes through moisture separators and steam dryers and then flows to the turbine. By generating steam directly in the reactor vessel, the power generation system contains only two heat transfer loops. The primary loop transports the steam from the reactor vessel directly to the turbine, which generates electricity. The secondary coolant loop removes excess heat from the primary

loop in the condenser. From the condenser the primary condensate proceeds into the feedwater stage and the secondary coolant loop removes the excess heat to the environment (see Figure 3-2).

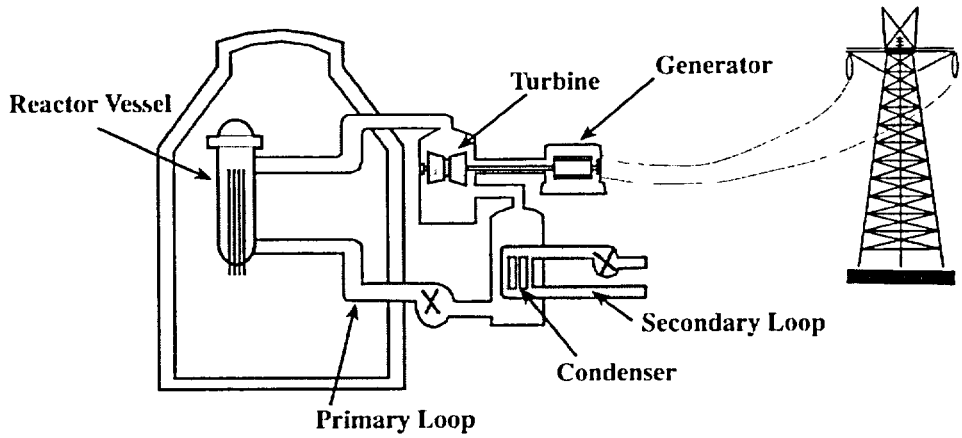

Figure 3-2. Boiling Water Reactor

3.1.1.3 Fast Breeder Reactors

In the FBR, such as Fermi, Unit 1, liquid sodium is used as the reactor coolant instead of water. The Fermi, Unit 1, FBR used the fissile isotope of uranium as fuel. During the chain reaction, while some neutrons are fissioning plutonium atoms and releasing heat energy, others are captured by uranium atoms, which are then converted into more plutonium atoms. Depending on design, a fast breeder can produce 1.4 new plutonium atoms for every one fissioned–enough to refuel another reactor in 10 years. Fast breeders also generally have a higher power density in the core (thus, a smaller reactor) and better heat transfer characteristics, which improves power-plant efficiency. The Fermi, Unit 1, reactor also utilized a steam cycle to generate electricity, similar to a PWR. However, the Fermi, Unit 1, reactor had two sodium loops. Primary-loop liquid sodium was circulated through the reactor core, where it absorbed the heat generated by the reactor, and then through a heat exchanger, where its heat was transferred to the second (intermediate) sodium loop. The intermediate-loop liquid sodium was then circulated through a steam generator. The steam produced in the steam generators was then circulated to the turbine generators to produce electricity.

At this time, there are no commercial FBRs operating or under construction in the United States. Fermi, Unit 1, is currently in SAFSTOR. The environmental impacts described in this Supplement for FBRs are applicable to Fermi, Unit 1.

3.1.1.4 High-Temperature Gas-Cooled Reactors

Commercial HTGRs, operated in the United States at Peach Bottom, Unit 1, and Fort St. Vrain, use helium gas instead of water (as in LWRs) to transfer the heat from the reactor core to produce steam. In HTGRs, the entire primary coolant system, including the reactor, the steam generators, and the helium circulators, is housed within a prestressed concrete or steel reactor vessel. The helium circulators pump the pressurized coolant through the core, where it absorbs the heat from the fission process. The helium then enters the steam generators, which transfer the heat to the secondary system. The secondary system is a steam cycle similar to that found in any modern fossil-fuel facility. Superheated steam is produced in the steam generators and routed to the turbine generator, which generates the electricity (Fuller 1988).

At this time, there are no HTGRs operating or under construction in the United States. Decommissioning at Fort St. Vrain is complete and the license is terminated, and Peach Bottom, Unit 1, is currently in SAFSTOR. The environmental impacts described in this Supplement for HTGRs are applicable to Peach Bottom, Unit 1.

3.1.2 Types of Structures Located at a Nuclear Power Facility

As discussed in Chapter 1, the definition of decommissioning includes the reduction of residual radioactivity to a level that permits release of the property and termination of the license. As a result, the decontamination and/or dismantlement of those SSCs that are radioactive are, by definition, included within the scope of this Supplement as part of decommissioning. If the structures must be decontaminated or parts of the structures removed to meet the requirements for the termination of the NRC license, those activities are also considered within scope as part of the decommissioning process. This includes removing nonradiological structures necessary to decontaminate another structure. Additionally, the impacts of dismantling all SSCs that were built or installed at the site to support power production are considered in this Supplement. This section discusses all the structures that will be referred to later in the document as background information for the reader.

Nuclear power plants generally contain similar facilities. They all contain a nuclear steam supply system, as described in Section 3.1.1 above. Additionally, there are a number of common SSCs necessary for plant operation. However, the layout of buildings and structures varies considerably among the sites. For example, control rooms may be located in the auxiliary building, in a separate control building, or in a radwaste and control building. Thus, the following list describes typical structures located on most sites.

- Containment or reactor building: The containment or reactor building in a PWR is a massive concrete or steel structure that houses the reactor vessel, reactor coolant piping and pumps, steam generators, pressurizer, pumps, and associated piping. The reactor building structure of a BWR generally includes a containment structure and a shield building. The containment is a massive concrete or steel structure that houses the reactor vessel, the reactor coolant piping and pumps, and the suppression pool. It is located inside a somewhat less substantive structure called the shield building. The shield building for a BWR also generally contains the spent fuel pool and the new fuel pool.

  The reactor building for both PWRs and BWRs is designed to withstand such disasters as hurricanes and earthquakes. The containment's ability to withstand such disasters and to contain the effects of accidents initiated by system failures are the principal protections against releasing radioactive material to the environment.

  The containment building for the FBR is a steel-domed structure that contains the upper end of the reactor vessel and the fuel-handling equipment. Below ground there is considerable concrete shielding.

  The HTGRs have two containment structures. Peach Bottom's inner containment structure is made of a steel pressure vessel and Fort St. Vrain's was made of prestressed concrete. This inner vessel houses the entire primary coolant system, the interconnecting ducts and plenums, the reactor core assembly, and the steam generator. The inner vessel is housed inside a second containment structure, which is designed to contain the entire primary coolant system helium under conditions postulated for the design basis accident.

- Fuel building: For PWRs, the fuel building has a fuel pool that is used for the storage and servicing of spent fuel and the preparation of new fuel for insertion into the reactor. This building is connected to the reactor building by a transfer tube or channel that is used to move new fuel into the reactor and to move spent fuel out of the reactor for storage.

- Turbine building: The turbine building houses the turbine generators, condenser, feedwater heaters, condensate and feedwater pumps, waste-heat rejection system, pumps, and equipment that supports those systems. Primary coolant is circulated through these systems in BWRs, thereby causing them to become slightly contaminated. Primary coolant is not circulated through the turbine building systems in PWRs. However, it is not unusual for portions of the turbine building to become mildly contaminated during power generation at PWRs.

- Auxiliary buildings: Auxiliary buildings house such support systems as the ventilation system, the emergency core cooling system, the laundry facilities, water treatment system, and waste treatment system. The auxiliary building may also contain the emergency diesel generators and, in some PWRs, the fuel storage facility. Often, the facility's control room is also located in the auxiliary building.

- Diesel generator building: Often, there is a separate building for housing the emergency diesel generators if they are not located in the auxiliary building. The emergency diesel generators do not become contaminated or activated.

- Pumphouses: Various pumphouses may be present onsite for circulating water, standby service water, or makeup water. Pumphouses that carry clean water do not require radiological decommissioning.

- Cooling towers: Cooling towers are structures that are designed to remove excess heat from the condenser without dumping the heat directly into water bodies, such as lakes or rivers. There are two principal types of cooling towers: mechanical draft towers and natural draft towers. Most nuclear plants that have once-through cooling do not have cooling towers associated with them (see the descriptions in Section 3.1.3). However, five facilities with once-through cooling also have cooling towers.

- Radwaste facilities: If the radwaste facilities are not contained in the auxiliary building, they may be located in a separate solid radwaste building. An interim radwaste storage facility may also be used.

- Ventilation stack: Many older nuclear power plants, particularly BWRs, have ventilation stacks to discharge gaseous waste effluents and ventilation air. These stacks can be 90 m (300 ft) tall or more and contain monitoring systems to ensure that radioactive gaseous discharges are below fixed release limits. Radioactive gaseous effluents are treated and processed prior to discharge out the stack.

The following structures may also be part of the nuclear reactor facility but are not evaluated in this Supplement.

- Independent spent fuel storage installations (ISFSI): An ISFSI is designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. ISFSIs may be located at the site of a nuclear power plant or at another location. The most common design for an ISFSI, at this time, is a concrete pad with dry casks containing spent fuel bundles. ISFSIs are used by operating plants that require increased spent fuel storage capability because their spent fuel pools have reached

capacity. Decommissioning facilities also use ISFSIs. The first dry-storage installation was licensed by the NRC in 1986. As of August 21, 2002, there were 23 nuclear power facilities licensed to use dry storage: Surry, Oconee, H.B. Robinson, Calvert Cliffs, Fort St. Vrain, Palisades, Point Beach, Prairie Island, Davis-Besse, Susquehanna, Arkansas Nuclear One, North Anna, Trojan, Dresden, Hatch, McGuire, Oyster Creek, Peach Bottom, Yankee Rowe, Fitzpatrick, Rancho Seco, Maine Yankee, and U.S. Department of Energy (DOE [TMI-2 fuel debris]) at Idaho National Engineering and Environmental Laboratory.

An ISFSI can be constructed and operated and decommissioned either under the same license that is used for the operating or decommissioning facility called a general license under 10 CFR Part 50 or a specific license under 10 CFR Part 72 license. If a licensee chose to operate the ISFSI under a Part 50 license, it could, seek a site-specific 10 CFR Part 72 license for the ISFSI, thus allowing termination of the Part 50 license at the end of the decommissioning process. The NRC staff would also be required to conduct an environmental assessment of the licensee's request for a site-specific 10 CFR Part 72 license.

- Switchyard: A plant site also contains a large switchyard, where the electric voltage is stepped up and fed into the regional power distribution system. The switchyard is an integral part of the electric power transmission grid, and may remain on the site even after termination of the license.

- Administrative, training, and security buildings: Normally, the administrative, training, and security buildings are located outside the radiation protection zones, and no radiological hazards are present.

3.1.3 Description of Systems

After permanent cessation of operations and transfer of the fuel from the reactor vessel, licensees begin to shut down systems that are no longer operated in a decommissioning plant. However, specific systems will continue to be used during the different phases of the decommissioning process although in some cases in reduced roles. This section provides background information related to the systems, explains the differences between the systems' use during operations and during the decommissioning process, and explains how their continued operation could impact the environment during the decommissioning process. Lobner et al. (1990) provides more comprehensive descriptions of these systems in U.S. commercial LWRs. The systems described below are typical and may differ at specific facilities.

- Cooling and auxiliary water systems: The predominant water use at an operating nuclear power plant is for removing excess heat generated in the reactor by the condenser cooling system. The quantity of water that is used for condenser cooling in an operating plant is a function of several factors, including the capacity rating of the plant and the increase in cooling water temperature from the discharge to the intake. The cooling water system for the reactor is not operated after the facility has permanently ceased power operations and the fuel has been removed from the reactor vessel. Therefore, water use is greatly reduced when operations cease. However, systems are not immediately drained upon cessation of operation and are frequently left in place for a period of time to provide shielding to the workers.

  There are two major types of cooling systems for operating plants: once-through cooling and closed-cycle cooling.

  In a once-through cooling system, circulating water for condenser cooling is obtained from an adjacent body of water, such as a lake or river, passed through the condenser tubes, and returned at a higher temperature to the adjacent body of water. Flow through the condenser for a 1000-MW plant during operations is typically 45 to 65 m^3/s (700,000 to 1,000,000 gpm) (NRC 1996). The waste heat is dissipated to the atmosphere mainly by evaporation from the water body and, to a much smaller extent, by conduction, convection, and thermal radiation loss.

  In a closed-cycle system at an operating plant, the cooling water is recirculated through the condenser after the waste heat is removed by dissipation to the atmosphere, usually by circulating the water through large cooling towers constructed for that purpose. The average for makeup water withdrawals for a 1000-MW plant during operations is typically about 0.9 to 1.1 m^3/s (14,000 to 18,000 gpm). Recirculating cooling systems consist of either natural draft or mechanical draft cooling towers, cooling ponds, lakes, or canals. Because the predominant cooling mechanism associated with closed-cycle systems is evaporation, most of the water used for cooling is consumed and is not returned to the water source.

  In addition to removing heat from the reactor of an operating facility, cooling water is also provided to the service water system and to the auxiliary water system. These systems account for 1 to 15 percent of the water needed for the condenser cooling. The auxiliary water systems include emergency core cooling systems, the containment spray and cooling system, the emergency feedwater system, the component cooling water system, and the spent fuel pool water systems. Most of these systems would not be needed following permanent cessation of operations. However, some, such as the systems for the spent fuel pool cooling, will be used after the plant has shut down.

- Waste systems (gaseous, liquid, solid, and nonradioactive): The gaseous waste management system in an operating nuclear facility collects fission products, mainly noble gases, that accumulate in the primary coolant. It is designed to reduce the radioactive material in gaseous waste before discharge to meet the dose design objectives in 10 CFR Part 50, Appendix I. During decommissioning, the gaseous waste management system is used during the decontamination and dismantlement of certain tanks or pipes. It is also used during dismantlement to assist in the control of radioactive dust or loose contamination. In addition, high-efficiency particulate air (HEPA) filters are used to remove radioactive material on a localized basis. For example, when removing concrete with a power hammer or drill in the containment building, a temporary plastic tent equipped with a HEPA filter, prevents contaminated dust particles from entering the building. A second set of HEPA filters is located on the exhaust vent pathway for the building. The quantities of gaseous effluents released from operating plants and those in the decommissioning process are controlled by the administrative limits that are defined in the Offsite Dose Calculation Manual (ODCM) or similar document, which is specific for each plant. The limits in the ODCM are designed to provide reasonable assurance that radioactive material discharged in gaseous effluents are not in excess of the limits specified in 10 CFR Part 20, Appendix B, thereby limiting the exposure of a member of the public in an unrestricted area.

  The liquid radioactive waste system in operating nuclear power plants is used to collect and process liquid wastes collected from equipment leaks, valve and pump seal leaks, laundry wastes, personnel and equipment wastes, and steam generator blowdown (for PWRs), as well as building, laboratory, and floor drains. Each of these sources of liquid wastes receives varying degrees and types of treatment before storage, reuse, or discharge to the environment. During decommissioning, any radioactive liquids from operation of decommissioning activities in the facility will be processed and disposed of, thus necessitating the use of the liquid radioactive waste system. Some systems such as the laundry will likely still operate for a period of time, but others like the steam generator blowdown will not. Controls for limiting the release of radiological liquid effluents are described in the facility's ODCM. Controls are based on (1) concentrations of radioactive materials in liquid effluents and projected dose or (2) dose commitments to a member of the public. Concentrations of radioactive material that may be released in liquid effluents to unrestricted areas are limited to the concentration specified in 10 CFR Part 20, Appendix B, Table 2.

  Solid low-level waste (LLW) from nuclear power plants is generated by removal of radionuclides from liquid waste streams, filtration of airborne gaseous emissions, and removal of contaminated material. The major source of solid LLW during decommissioning is the decommissioning process itself. Removal of contamination involves the use of protective clothing and cleaning rags. Dismantlement results in concrete or metal that has

low levels of contamination or activation products. While the amount of liquid and gaseous radioactive waste generated is usually lower for decommissioning plants than for operating plants, the quantity of solid LLW being generated is significantly higher during decommissioning.

Solid waste is packaged in containers to meet the applicable requirements of 49 CFR Parts 171 through 177. Disposal and transportation are performed in accordance with the applicable requirements of 10 CFR Part 61 and 10 CFR Part 71, respectively.

Solid radioactive waste generated during either decommissioning or operations is usually shipped to a LLW processor or, in some cases, directly to a LLW disposal site. Volume reduction may occur both onsite and offsite. The most common onsite volume reduction techniques are high-pressure compacting in waste drums, dewatering and evaporating wet wastes, monitoring waste streams to segregate wastes, and sorting. Offsite waste management vendors compact wastes at ultra-high pressures, incinerate dry active waste, separate and incinerate oily and organic wastes, and asphalt-solidify resins and sludges before the waste is sent to the LLW site.

Nonradioactive wastes, including storm water system and sewage waste, are also generated during the decommissioning process. For example, use of hazardous oils or other chemicals in solvent cleaning and repair of equipment produces some nonradioactive wastes. Also, during decommissioning, additional quantities of nonradioactive waste (paint, asbestos) are generated or removed. Disposal of essentially all of the hazardous chemicals used at nuclear power plants is regulated by the Resource Conservation and Recovery Act (RCRA) of 1976 or by National Pollutant Discharge Elimination System (NPDES) permits, which are regulated by the U.S. Environmental Protection Agency (EPA) and administered by EPA, or if authorized, by the States to control the amount and types of pollutants that may be discharged from the plant.

Mixed waste is regulated under RCRA, the Atomic Energy Act, and NRC and is sent to a facility that is licensed to handle mixed waste.

- Miscellaneous mechanical systems: A variety of existing plant mechanical systems may continue to be used during plant decommissioning, including

  - the fire protection system
  - the heating, ventilation, and air conditioning (HVAC) system

- the fuel-handling system
- various cranes and hoists.

The use of these systems generally does not have a direct impact on the environment. For example, the HVAC system that is used inside a contaminated area would be exhausted to the gaseous waste management system.

- Instrumentation and control systems: While most instrumentation and control systems in the plant can be deactivated after permanent shutdown and defueling of the reactor, a few may continue to be used to support decommissioning operations, including:

  - the radiation monitoring system, which detects, measures, and records radiation levels during decommissioning operations and alerts plant staff of off-normal readings, and
  - the security system, which monitors the plant protected area to prevent uncontrolled access.

  In most cases, these systems are altered or reduced during the decommissioning process. The use of these systems during the decommissioning process does not impact the environment.

- Electrical systems: Numerous electrical systems may continue to be used during decommissioning operations. These include systems needed to provide uninterrupted power, lighting, and communication. In some cases, licensees have installed a new power distribution system, re-energizing only those loads that are necessary for continued use during decommissioning. In many facilities, the circuits that are being used are color-coded so that workers can easily identify the live circuits. Both of these practices are intended to prevent workers from cutting into a live wire during the decommissioning process.

- Spent fuel storage systems: Before beginning the decommissioning process, the licensee must certify to the NRC that it has permanently removed the fuel from the reactor vessel. The fuel is first moved into the spent fuel pool, which is a specially designed water-filled basin. Even after the nuclear reactor is shut down, the fuel continues to generate decay heat from the radioactive decay of fission products. The rate at which the decay heat is generated decreases the longer the reactor has been shut down. Therefore, the longer the time from last criticality, the less heat the spent fuel gives off. Storing the spent fuel in a pool of water provides an adequate heat sink for the removal of heat from the irradiated fuel. In addition, the fuel is located far enough under water that the radiation emanating from the fuel is shielded by the water, thus protecting workers from the radiation. After the

fuel has cooled adequately, it can be stored in an ISFSI in air-cooled dry casks. Typically, transfer of spent fuel to an ISFSI occurs after the fuel has cooled for 5 years.

After removal of the fuel to the spent fuel pool, it is common for the licensee to reduce the security area at the facility to a "nuclear island" that focuses primarily on the storage area for the spent fuel. This allows the spent fuel to be protected and the security system to cover only the storage location for the spent fuel.

At this time, there are no facilities for permanent disposal of high-level radioactive wastes (HLW). The Nuclear Waste Policy Act of 1982 defined the goals and structure of a program for permanent, deep geologic repositories for HLW and unreprocessed spent fuel. Under this Act, the DOE is responsible for developing permanent disposal capacity for the spent fuel and other high-level nuclear wastes. At the present time, DOE, as directed by Congress, is investigating a site in Yucca Mountain, Nevada, for a possible disposal facility. A HLW repository would be built and operated by DOE and licensed by the NRC.

The Commission believes (10 CFR 51.23(a)) there is reasonable assurance that at least one mined geological repository will be available in the first quarter of the 21st Century and that, within 30 years beyond the licensed life of operation for any reactor, sufficient repository capacity will be available to dispose of the reactor's HLW and spent fuel generated up to that time.

Until a HLW repository is available or some interim central waste storage facility is approved and licensed, licensees generally store the fuel onsite, either in dry storage (ISFSI) or in wet storage in a spent fuel pool. Licensees are prohibited from shipping spent fuel from one reactor spent fuel pool to another without NRC approval by license amendment.

The Commission has independently, in a separate proceeding (the Waste Confidence Proceeding), made a finding that there is

> reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations (54 FR 39767).

The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at this time (64 FR 68005). Accordingly, the Commission reaffirmed its findings

of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The staff relies on the Waste Confidence Rule, but for completeness has elected to include in this Supplement information related to the storage and maintenance of fuel in a spent fuel pool.

- Transportation systems: There are four broad classes of shipments to and from operating nuclear power plants: (1) routinely generated LLW transported from plants to disposal facilities, (2) routine LLW shipped to offsite facilities for volume reduction, (3) nuclear fuel shipments from fuel-fabrication facilities to plants for loading into reactors, and (4) spent fuel shipments to other nuclear power plants with available storage space (an infrequent occurrence that is usually limited to plants owned by the same utility).

  The transportation of radioactive materials is regulated jointly at the Federal level by the U.S. Department of Transportation (DOT) and the NRC. The responsibilities of the two agencies are delineated in a Memorandum of Understanding (see 44 FR 38690). Most LLW is shipped in packages authorized by the DOT. Some packages for larger quantities of LLW require NRC certification. The LLW packages can be loaded onto trucks, trains, barges, or other ships for shipment to the LLW disposal site. In general, the areas regulated by the agencies are as follows:

  - DOT – Regulates shippers and carriers of radioactive material and the conditions of transport, including routing, tiedowns, radiological controls, vehicle requirements, hazard communication, handling, storage, emergency response information, and employee training. DOT regulations are located in the Code of Federal Regulations, Title 49, "Transportation."

  - NRC – Regulates users of radioactive material and the design, construction, use, and maintenance of shipping containers used for larger quantities of radioactive material and fissile material such as uranium. NRC regulations are located in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material."

  Title 10 CFR 71.47 states that under normal transportation conditions, each package of radioactive materials must be designed and prepared for shipment such that the radiation level does not exceed 2 mSv/h (200 mrem/h) at any point on the external surface of the package and 0.1 mSv/h (10 mrem/h) at any point 1 m (3.3 ft) from the packaging surface. This type of shipment is called a nonexclusive use shipment. If the package exceeds the limits specified for nonexclusive use shipments, it must be transported by exclusive use shipment only. The radiation limits for exclusive use packages are the following:

- At any point on the package surface: 2 mSv/h (200 mrem/h). For closed transport vehicle only: 10 mSv/h (1000 mrem/h)
- At 2 m (6.6 ft) from lateral surfaces of vehicle: 0.1 mSv/h (10 mrem/h)
- At all external surfaces of the vehicle: 2 mSv/h (200 mrem/h)
- In the occupied area of the vehicle: 0.02 mSv/h (2 mrem/h), with certain exceptions.

For more information regarding waste packaging and radioactive transportation regulations, see 10 CFR Part 71.

The frequency of waste shipments increases sharply during the decommissioning period. In some cases, such as the shipment of large components (e.g., steam generators, reactor vessels, or pressurizers), the waste packaging is unique compared to most shipments during operations. However, the licensee is still required to meet the regulations discussed above, unless the NRC approves an exemption after a thorough analysis of the licensee's proposal.

3.1.4 Formation and Location of Radioactive Contamination and Activation in an Operating Plant

During reactor operation, a large inventory of radioactive fission products builds up within the fuel. Virtually all of the fission products are contained within the fuel pellets. The fuel pellets are enclosed in hollow metal rods, which are hermetically sealed to prevent further release of fission products. Occasionally fuel rods develop small leaks, allowing a small fraction of the fission products to contaminate the reactor coolant. The radioactive contamination in the reactor coolant is the source of gaseous, liquid, and solid radioactive wastes generated at LWRs during operation. Most of the contamination in the reactor coolant system is from the activation of corrosion products and not from leaking fuel.

There are two sources of radioactive material: contamination and activation. Contaminated materials are unintentionally transported through the facility by workers, equipment, and, to some degree, air movement. Although many precautions are taken to prevent the movement of contaminated material in a nuclear facility and to clean up any contaminated materials that may be found, it is likely that contamination will occur in the reactor building, around the spent fuel pool, and around specific SSCs in the auxiliary building and other buildings and equipment in the area near the reactor. The areas known to contain contamination are labeled by the licensee, who routinely checks for contamination and removes as much as possible during operations. Radioactive contamination may be deposited from the air or dissolved in water and subsequently deposited onto material such as concrete. Radioactive contamination is generally

located on or near the surface of materials such as metals, high-density concrete, or painted walls. It can travel farther into unpainted surfaces or lower-density concrete. Radioactive contamination can usually be removed from surface areas by washing, scrubbing, spraying, or, in extreme cases, by physically removing the outer layers of the surface material.

Activation products are also formed during reactor operation. Activation products are radioactive materials created when stable substances are bombarded by neutrons. Concrete and steel surrounding the core of the reactor are the most common types of activated products. Activation products cannot be removed by the processes used to remove contamination. Activation products are incorporated into the molecular structure of the material and cannot be wiped off or removed. The entire structure (or portions) that have been activated must be removed and treated as radioactive waste. Activated metal and concrete contain the single largest inventory of radionuclides with the exception of the spent fuel, in facilities that are being decommissioned. The radioactive decay of activation products, both of structures as well as corrosion products, is the main source of radiation exposure to plant personnel.

The spent fuel contains the largest amount of radioactive material at a permanently shutdown facility followed by the reactor vessel, internals, and bioshield. Systems containing smaller amounts of radioactive material include the steam generator, pressurizer, piping of the primary system and other systems, piping, as well as the radwaste systems. Minor contamination is found in the secondary systems and miscellaneous piping.

3.2 Decommissioning Options

This Supplement evaluates the environmental impacts of three decommissioning options or combinations of the options. These options, first identified in the 1988 Generic Environmental Impact Statement (GEIS) using the acronyms DECON, SAFSTOR, and ENTOMB, are defined as follows:

DECON: The equipment, structures, and portions of the facility and site that contain radioactive contaminants are promptly removed or decontaminated to a level that permits termination of the license shortly after cessation of operations.

SAFSTOR: The facility is placed in a safe, stable condition and maintained in that state (safe storage) until it is subsequently decontaminated and dismantled to levels that permit license termination. The determination of SAFSTOR includes those activities necessary for the final decontamination and dismantlement of the facility. During SAFSTOR, a facility is left intact, but the fuel has been removed from the reactor vessel, and radioactive liquids have been drained from systems and components and then processed. Radioactive decay

occurs during the SAFSTOR period, thus reducing the quantity of contaminated and radioactive material that must be disposed of during decontamination and dismantlement. The definition of SAFSTOR also includes the decontamination and dismantlement of the facility at the end of the storage period.

ENTOMB: Radioactive SSCs are encased in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license.

The choice of decommissioning option is left entirely to the licensee, provided that it can be performed according to the NRC's regulations. This choice is communicated to the NRC and the public in the post-shutdown decommissioning activities report (PSDAR). In addition, the licensee may choose to combine the DECON and SAFSTOR options. For example, after power operations cease at a facility, a licensee could use a short storage period for planning purposes, followed by removal of large components (such as the steam generators, pressurizer, and reactor vessel internals), place the facility in storage for 30 years, and eventually finish the decontamination and dismantlement process.

Although the selection of the decommissioning option is up to the licensee, the NRC requires the licensee to re-evaluate its selection if the option (1) could not be completed as described, (2) could not be completed within 60 years of the permanent cessation of plant operations, (3) included activities that would endanger the health and safety of the public by being outside of the NRC's health and safety regulations, or (4) would result in a significant impact to the environment.

To date, most utilities have used DECON or SAFSTOR to decommission reactors. Several sites have performed some incremental decontamination and dismantlement during the storage period of SAFSTOR, a combination of SAFSTOR and DECON. A site using DECON may have a short period of time (1 to 4 years) when the facility is in SAFSTOR. Several licensees continue to conduct limited decommissioning activities during a SAFSTOR period as personnel, money, or other factors become available. This process of occasionally conducting active decontamination and dismantlement is referred to as incremental DECON. No utilities have used the ENTOMB option for a commercial nuclear power reactor.

The following sections provide a general overview of each decommissioning option.

3.2.1 DECON

The DECON decommissioning option involves removing or decontaminating equipment, structures, and portions of the facility and site that contain radioactive contaminants to a level that permits termination of the license, as defined in Regulatory Guide 1.184 (NRC 2000a).

There are several advantages to using the DECON option of decommissioning. One is that the facility license is quickly terminated so that the facility and site become available for other purposes. By beginning the decontamination and dismantlement process soon after permanent cessation of operation, the available work force can be maintained and is highly knowledgeable about the facility. The availability of facilities willing to accept LLW may also be a factor in the licensee's decision to pursue the DECON option. Currently, the estimated cost of decommissioning a site using DECON is less than SAFSTOR due primarily to price escalation in the disposal of LLW. Because most activities that occur during DECON also occur during SAFSTOR, the price for decommissioning at a later date is greater because of the cost of storage and inflation (NRC 2000c). DECON also eliminates the need for long-term security, maintenance, and surveillance of the facility (excluding the onsite storage of spent fuel), which is required for the other decommissioning options.

The major disadvantages of DECON are the higher worker dose and significant initial expenditures. Also, compared to SAFSTOR, DECON requires a larger potential commitment of disposal site space (NRC 2000c).

The general activities that may occur during DECON are listed below (NRC 2000d):

- draining (and potentially flushing) of some contaminated systems and removal of resins from ion exchangers
- setup activities such as establishing monitoring stations or designing and fabricating special shielding and contamination-control envelopes to facilitate decommissioning activities
- reduction of site-security area (setup of new security monitoring stations)
- modification of the control room or establishing an alternate control room
- site surveys
- decontamination of radioactive components, including use of chemical decontamination techniques

- removal of reactor vessel and internals
- removal of other large components, including major radioactive components
- removal of the balance of the primary system (charging system, boron control system, etc.)
- general activities related to removing other significant radioactive components
- decontamination and/or dismantlement of structures or buildings
- temporary onsite storage of components
- shipment and processing of LLW, including compaction or incineration of the waste
- removal of the spent fuel and Greater-than-Class-C (GTCC) Waste to an ISFSI
- removal of hazardous radioactive (mixed) wastes
- changes in management and staffing.

3.2.2 SAFSTOR

The SAFSTOR decommissioning option involves placing the facility in a safe, stable condition and maintaining that state for a period of time, followed by subsequent decontamination and dismantlement to levels that permit license termination. During the storage period of SAFSTOR, the facility is left intact. The fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems and components and processed. Radioactive decay occurs during the storage period, reducing the quantity of contaminated and radioactive material that must be disposed of during decontamination and dismantlement.

There are several advantages to using the SAFSTOR option of decommissioning. A substantial reduction in radioactive material as a result of radioactive decay during the storage period reduces worker and public doses below those of the DECON alternative. Since there is potentially less radioactive waste, less waste-disposal space is required. Moreover, the costs immediately following permanent cessation of operations are lower than costs during the first years of DECON because of reduced amounts of activity and a smaller work force (NRC 2000c).

However, because of the time gap between cessation of operations and decommissioning activities, SAFSTOR can result in a shortage of personnel familiar with the facility at the time of dismantlement and decontamination. During the prolonged period of storage, the plant requires continued maintenance, security, and surveillance. Also, uncertainties regarding the availability and cost of LLW sites in the future could mean higher costs for decontamination and dismantlement (NRC 2000c).

Activities that typically occur during the preparation and storage stages of the SAFSTOR process are described below (NRC 2000d).

<u>During preparation</u>:

- draining (and potential flushing) of some systems and removal of resins from ion exchangers
- spent fuel pool cooling systems reconfiguration
- decontamination of highly contaminated and high dose areas as necessary
- performance of a radiological assessment as a baseline before storage
- removal of LLW that is ready to be shipped
- shipment and processing or storage of the fuel and GTCC waste
- de-energizing or deactivating systems and equipment
- reconfiguration of ventilation systems, fire protection systems, and spent fuel pool cooling system for use during storage
- establishment of inspection and monitoring plans for use during storage
- maintenance of any systems critical to final dismantlement during storage
- changes in management and staffing.

<u>During storage</u>:

- performance of preventative and corrective maintenance on plant systems that will be operating and/or functional during storage

- maintenance to preserve structural integrity
- maintenance of security systems
- maintenance of radiation effluent and environmental monitoring programs
- processing of any radwaste generated (usually small amounts).

Following the storage period, the facility is decontaminated and dismantled to radiological levels that allow termination of the license. Activities during this period of time will be the same activities that occur for DECON.

3.2.3 ENTOMB

The ENTOMB decommissioning method was defined in the Supplementary Information to the 1988 Decommissioning Rule (53 FR 24018) as the option in which radioactive contaminants are encased in a structurally long-lived material, such as concrete. The entombed structure is appropriately maintained and surveillance is continued until the radioactivity decays to a level permitting unrestricted release of the property (NRC 1988).

Currently, 10 CFR 50.82 (a)(3) requires that decommissioning be completed within 60 years of permanent cessation of operations, and completion of decommissioning beyond 60 years be approved by the NRC only when necessary to protect public health and safety. The factors that could be considered by the Commission in evaluating an option that provides for the completion of decommissioning beyond 60 years of permanent cessation of operation include unavailability of waste disposal capacity and site-specific factors affecting the licensee's capability to carry out decommissioning, including the presence of other nuclear facilities at the site.

The current regulations, pertaining to the decommissioning of nuclear reactors promulgated in 1988, are also structured to favor decommissioning options that result in unrestricted release of the site. As noted in the supplementary information for the June 27, 1988, final rule, the ENTOMB option was not specifically precluded because it was recognized that it might be an allowable option for protecting public health and safety.

The 1997 Rule for Radiological Criteria for License Termination (64 FR 39058) established criteria (10 CFR Part 20, Subpart E) that allow for both restricted and unrestricted release of property. Under a restricted release, the dose to the average member of the critical group must not exceed 0.25 mSv/yr (25 mrem/yr) total effective dose equivalent (TEDE) and must be as low as reasonably achievable (ALARA) with the restrictions in place. If the restrictions were no longer in effect, the dose due to residual radioactivity could not exceed 1 mSv/yr (100 mrem/yr)

(or 5 mSv/yr [500 rem/yr], if additional conditions are met) TEDE and must be ALARA. These caps were chosen to provide a safety net in the highly unlikely event that the restrictions failed.

In the Staff Requirements Memorandum on the ENTOMB option, dated July 20, 2000 (NRC 2000b), the Commission directed that

> [T]he staff closely coordinate this rulemaking effort for this rulemaking with the ongoing efforts to update the generic environmental impact statement for the decommissioning of power reactors. The staff should include the entombment option in the GEIS recognizing that not all entombment proposals can be forecast but that the GEIS would provide a bounding analysis. The staff should also address the issue of entombing Greater Than Class C waste for this category of waste.

On September 18, 2001, the Commission approved the staff's rulemaking plan (see Section 2.2.2) for potential development of a rule to allow entombment as a decommissioning option for power reactors. NRC published an Advance Notice of Proposed Rulemaking (ANPR) on October 16, 2001 (66 FR 52551) seeking stakeholder input on three proposed regulatory options and whether entombment was a viable decommissioning alternative. The ANPR comment period closed on December 31, 2001. NRC received 19 comments from: six States; eight licensees; the Nuclear Energy Institute (NEI); the U.S. Environmental Protection Agency (EPA); the Conference of Radiation Control Program Directors' E-24 Committee on Decommissioning and Decontamination (CRCPD E-24 Committee); the Southeast Compact Commission (SCC); and a private individual.

Generally, the eight utilities and NEI stated that they would have entombment available as a decommissioning option; however, none unequivocally committed to using entombment for their decommissioning process. Some Agreement State commenters endorsed the 10 CFR Part 20 dose limits, with one State adding that a time limit to reach the dose rates should be considered. Although one State advocated extending the decommissioning period beyond 60 years, most were silent on the decommissioning regulations in 10 CFR Part 50. The staff notes that there was no consensus on a preferred option. NRC staff has considered the comments received and has prepared a paper transmitting the staff's recommendations to the Commission. As of the date of this publication the Commission has not acted on the staff's recommendations.

The assessment of impacts associated with the ENTOMB option presented in this GEIS is independent of a prospective rulemaking before the Commission. The staff is making the assumption that environmental issues arising from any rulemaking effort will be addressed in the rulemaking and its supporting environmental documentation. These issues may include: (1) the long-term onsite retention of radioactive materials, including those that may be classified

as GTCC, (2) issues related to long-term NRC oversight and monitoring requirements, (3) durability of institutional controls and site-engineered barriers, and (4) site-specific requirements.

The purpose of the entombment process is to isolate the entombed radioactive waste so that the reactor facility can be released and the license terminated. Therefore, prior to entombment, (1) an accurate characterization of the radioactive materials that are to remain is needed, and (2) the adequacy of the entombment configuration to isolate the entombed radioactive waste must be determined. Because of the requirement in the regulation to complete decommissioning within 60 years, no licensee has proposed the use of ENTOMB as the preferred decommissioning option for any of the nuclear power reactors currently undergoing decommissioning. The staff can envision a large number of entombment scenarios arranged along a continuum, differing primarily on the amount of decontamination and dismantlement done prior to the actual entombment.

The staff evaluated the impacts associated with the entombment options by developing two scenarios that have been designated ENTOMB1 and ENTOMB2. These two scenarios were developed specifically to envelope a wide range of potential options by describing two possible extreme cases of entombment. ENTOMB1 assumes significant decontamination and dismantlement and removal of all contamination and activation involving long-lived radioactive isotopes prior to entombment. ENTOMB2 assumes significantly less decontamination and dismantlement, significantly more engineered barriers, and the retention onsite of long-lived radioactive isotopes. Both options assume that the spent fuel would be removed from the facility and either transported to a permanent HLW repository or placed in an onsite ISFSI. Licensees choosing ENTOMB will adapt the entombment option to fit their specific site requirements.

ENTOMB1 is envisioned by the staff to begin the decommissioning process in a manner similar to the DECON option. The reactor would be defueled and the fuel initially placed into the spent fuel pool for some period prior to disposal at a licensed HLW repository or placed in an onsite ISFSI. Any decommissioning activity would be preceded by an accurate radiological characterization of SSCs throughout the facility. Active decommissioning would begin with draining and decontamination of SSCs throughout the facility with the goal of isolating and fixing contamination. SSCs would either be decontaminated or removed and either shipped to a LLW burial site or placed inside the reactor containment building. Offsite disposal of resins and considerable amounts of contaminated material would occur. There would likely be a chemical decontamination of the primary system. The reactor pressure vessel (RPV) and reactor internals would be removed, either intact or after sectioning, and disposed of offsite.

Any other SSCs that have long-lived activation products would be removed. Interim dry storage of the vessel, vessel internals, and any other SSCs containing long-lived activation products could occur onsite until a final disposal site for this waste (predominately GTCC waste) is identified. Steam generators and the pressurizer, depending on whether or not the components are contaminated with long-lived radioisotopes, would either be removed and disposed of offsite or retained inside the reactor containment. The spent fuel pool would be drained and decontaminated. The reactor building or containment would then be filled with SSCs

contaminated with relatively short-lived isotopes from the balance of the facility. Material would be placed in the building in a manner that would minimize the spread of any contamination (i.e., dry, contamination fixed, isolated). Engineered barriers would be put in place to deny access and eliminate the possibility of the release of any contamination to the environment. The reactor building or containment would be sealed and made weather tight.

The license termination monitoring program would be submitted and the site would be characterized. A partial site release would be completed for almost all of the site and the balance of the plant. The staff makes no assumptions as to when the license would be terminated and whether it would be terminated under the restricted or unrestricted provisions of 10 CFR Part 20, Subpart E. These decisions would likely be addressed as part of the staff's rulemaking effort related to entombment, explained above. The staff does assume that there would be a monitoring program period as long as 20 to 30 years to demonstrate that there was isolation of the contamination and adequate permanence of the structure.

The general activities that would occur during ENTOMB1 are listed below:

- planning and preparation activities
- draining (and potentially flushing) of contaminated systems and removal of resins from ion exchangers
- reduction of site-security area (optional)
- deactivation of support systems
- decontamination of radioactive components, including use of chemical decontamination techniques
- removal of the reactor vessel and internals
- removal of other large components, including major radioactive components

- removal of fuel from the spent fuel pool to an ISFSI
- dismantlement of remaining radioactively contaminated structures and placement of the dismantled structures in the reactor building
- installation of engineered barriers and other controls to prevent inadvertent intrusion and dispersion of contamination outside of the entombed structure
- filling of the void spaces in the previous reactor building structure with grout (concrete).

ENTOMB2 is also envisioned by the staff to begin the decommissioning process in a manner similar to the DECON option. The reactor would be defueled and the fuel initially placed into the spent fuel pool for some period prior to disposal at a licensed HLW repository or placed in an onsite ISFSI. Any decommissioning activity would be preceded by an accurate radiological characterization of SSCs throughout the facility. Active decommissioning would begin with the draining and decontamination of SSCs throughout the facility with the goal of isolating and fixing contamination. The spent fuel pool would be drained and decontaminated. SSCs would either be decontaminated or removed and either shipped to a LLW burial site or placed inside the reactor containment building (PWR) or the reactor building (BWR). Disposal offsite of resins would occur. The primary system would be drained, the RPV filled with contaminated material, all penetrations sealed, the RPV head reinstalled, and the reactor vessel filled with low-density concrete. Reactor internals would remain in place. Emphasis would be placed on draining and drying all systems and components and fixing contamination to prevent movement, either by air or liquid means. The steam generators and pressurizer would be laid up dry and remain in place. The reactor building or containment would then be filled with contaminated SSCs from the balance of the facility. Material would be placed in the building in a manner that would minimize the spread of any contamination (i.e., dry, contamination fixed, isolated).

Engineered barriers would be put in place to deny access and eliminate the possibility of the release of any contamination to the environment. The ceiling of the containment or reactor building, in the case of BWRs, may be lowered to near the refueling floor and to the top of the pressurizer for PWRs. The cavity of the remaining structure would be filled with a low-density concrete. The resulting structure would be sealed and made weather tight and covered with an engineered cap designed to deny access, and prevent the intrusion of water or the release of radioactive contamination to the environment.

The license termination monitoring program would be submitted and the site would be characterized. A partial site release would be completed for almost all of the site and the balance of the plant. The license would be likely terminated under the restricted release

provisions of 10 CFR Part 20, Subpart E, after a site-monitoring program that demonstrates the isolation of the contamination and the permanence of the structure. Monitoring could be as long as 100 years.

The general activities that would occur during ENTOMB2 are listed below:

- planning and preparation activities
- draining (and potentially flushing) of contaminated systems and removal of resins from ion exchangers
- deactivation of support systems
- removal of fuel from the spent fuel pool to an ISFSI
- dismantlement of all radioactively contaminated structures (other than the reactor building) and placement of the dismantled structures in the reactor building
- potentially lowering of the ceiling of the reactor building to near the refueling floor (in BWRs) or near the top of the pressurizer (in PWRs)
- installation of engineered barriers and other controls to prevent inadvertent intrusion and dispersion of contamination outside of the entombed structure
- filling of the cavity of the reactor building structure with low-density concrete
- placement of an engineered cap over the entombed structure to further isolate the structure from the environment.

The advantages of both ENTOMB options are reduced public exposure to radiation due to significantly less transportation of radioactive waste to an LLW disposal site and corresponding reduced cost of LLW disposal. An additional advantage of ENTOMB2 is related to the significant reduction in the amount of work activity, and thus a significant reduction in occupational exposures, as compared to the DECON or SAFSTOR decommissioning options.

3.3 Summary of Plants That Have Permanently Ceased Operations

Twenty-two of the commercial nuclear reactors licensed by the NRC have permanently shut down and have had their licenses terminated or are currently being decommissioned. This section presents the significant characteristics of these plants, the decommissioning options being used by each plant, and each plant's decommissioning activities.

3.3.1 Plant Sites

An overview of the shutdown plants can be found in Table 3-1, which includes 22 units shut down between 1963 and 1997. Table 3-2 summarizes important characteristics of the shutdown plants. The thermal power capabilities of the reactors ranged from 23 to 3411 MW(t). The reactors operated from just a few days (Shoreham) to 33 years (Big Rock Point). Since 1987, an average of one plant per year has been shut down.

Three of the 22 plants (Fort St. Vrain, Shoreham, and Pathfinder) have completed decommissioning and have had their 10 CFR Part 50 licenses terminated. Two of these three (Fort St. Vrain and Shoreham) used the DECON process for decommissioning. One facility, Shoreham, operated less than three full power days before being shut down and decommissioned so there was relatively little contamination. Another facility, Pathfinder, was placed in SAFSTOR and subsequently decommissioned. Eleven of the plants shut down prematurely. Three Mile Island, Unit 2, ceased power operations as a result of a severe accident. Three Mile Island, Unit 2, has been placed in a monitored storage mode until Unit 1 permanently ceases operation, at which time both units are to be decommissioned.

Eleven of the permanently shutdown plants were part of the U.S. Atomic Energy Commission's (AEC's) Demonstrations Program, including Big Rock Point; Dresden, Unit 1; Fermi, Unit 1; GE-VBWR; Humboldt Bay, Unit 3; Indian Point, Unit 1; La Crosse; Pathfinder; Peach Bottom, Unit 1; Yankee Rowe; and Saxton. These plants were prototype designs that were jointly funded by the AEC and commercial utilities. One of the plants, Pathfinder, has completed decommissioning and had its license terminated.

The most recent of the Demonstration Program reactors to shut down was Big Rock Point, which operated for 33 years and permanently shut down in 1997.

Table 3-1. Summary of Shutdown Plant Information

Types and Number of Shutdown Reactors	
BWR	8
PWR	11
HTGR	2
FBR	1
Decommissioning Option	
SAFSTOR	14
DECON	7
Accident cleanup followed by storage	1
Fuel Location	
Fuel onsite in pool	13
No fuel onsite[a]	8
Fuel onsite in ISFSI	1
Plan to move fuel to an ISFSI between 2000 and 2005	9

(a) Includes Three Mile Island, Unit 2, which has approximately 900 kg of fuel remaining onsite due to the accident.

Eight of the decommissioned or decommissioning plants are located in the northeast (or mid-Atlantic states), six in the west, six in the midwest, and one in the east. The majority of the shutdown plants (13) are situated on freshwater or impoundments, five others are in coastal or estuarine environments, and three others are on the Great Lakes.

3.3.2 Description of Decommissioning Options Selected

Seven decommissioned units are located on multi-unit sites in which the remaining units continue to operate and one multi-unit site shut down both units permanently. All eight of these licensees chose SAFSTOR as the decommissioning option. In most cases, SAFSTOR was chosen so that all units on a site could be decommissioned simultaneously. For various reasons, however, most shutdown units have done some decontamination and dismantlement.

The reasons cited by licensees for choosing DECON have included the availability of LLW capacity, availability of staff familiar with the plant, available funding, the licensee's intent to use the land for other purposes, influence by State or local government to complete decommissioning, or a combination of other reasons.

A number of the plants have combined the DECON and SAFSTOR process by either entering shorter SAFSTOR periods or by doing an incremental DECON, allowing the plant to use resources and "decommission as they go." Sites have combined the options, usually to achieve

economic advantages. For example, one site decided to shorten the SAFSTOR period and begin incremental dismantlement out of concern over future availability of a waste site and future costs of disposal. One site that prematurely shut down had a short SAFSTOR period to allow short-lived radioactive materials to decay and to conduct more detailed planning. Safety is another reason for combining the two options. Because of seismic safety concerns, one site undertook a major dismantling project to remove a 76-m (250-ft) concrete vent stack after it had been in SAFSTOR for 10 years.

The licensee determines the physical condition of the site after the decommissioning process. Some licensees intend to restore the site to "greenfield" status at the end of decommissioning, while others may install a non-nuclear facility. The NRC's regulatory authority is only over that portion of the facility that is contaminated. Some licensees will leave structures standing at the time of license termination, and others will not. While undergoing the decommissioning process, some licensees have opted for partial site release to decrease the size of the site area.

3.3.3 Decommissioning Process

The processes of decommissioning a power reactor facility for the SAFSTOR and DECON options can be divided into four stages, as shown in Figure 3-3. Figure 3-4 identifies the comparable stages that could be postulated for the two ENTOMB options. The order of each step and the duration of each stage vary, depending on plant-specific characteristics, such as location, operating history, reactor vendor, and licensee. The staff considered the differences in timing and choice of activities in evaluating the environmental impacts of decommissioning based on the experiences of currently decommissioning facilities.

Stage 1 in Figures 3-3 and 3-4 includes the licensee's initial preparations to shut down the plant and begin decommissioning. This stage is primarily administrative. Stage 1 typically lasts 1½ to 2½ years, regardless of the decommissioning option chosen. The main activities during the planning and preparation stage are determining the decommissioning option, making changes to the organization structure (layoffs, hiring experienced decommissioning contractors, etc.), and initiating licensing-basis changes.

The planning and preparation activities of Stage 1 vary, depending on when the licensee decides to cease operation. If the end of service is planned, the licensee may make plans for the decommissioning process and may even submit the PSDAR in advance of shutdown. This allows the plant to start major decommissioning activities immediately following the certification of permanent shutdown and the removal of the fuel (see Chapter 2, "Background Information

Related to Decommissioning Regulations," for a discussion of major decommissioning activities). If the end of service is unplanned, the licensee will probably not be ready to start decommissioning activities immediately following the certification of permanent shutdown and removal of fuel. Therefore, the order and duration of the activities in Stage 1 might vary compared to a planned shutdown. For most plants, the organizational changes will include a reduction in the number of staff as well as implementation of an employee-retention program to encourage the needed staff to stay on. However, one site actually had to increase staffing levels at the time of the permanent cessation of operation to start the DECON process. Initial plant characterization will be made during the planning activities and will continue throughout the decommissioning process. Because these activities are mostly planning, administrative, and organizational in nature, there is little potential for onsite or offsite impacts from these activities and only small amounts of decommissioning-related LLW generated.

Stage 2 in Figures 3-3 and 3-4 involves the transition of the plant from reactor operation to decommissioning. Stage 2 will last from about ½ to 1½ years for plants in SAFSTOR, DECON, and ENTOMB. All plants will have to transfer fuel out of the reactor and into the spent fuel pool. Isolation and stabilization of all unnecessary SSCs are also conducted during this stage.

Licensing-basis changes will continue during this stage, and the licensee may request an exemption from offsite emergency preparedness requirements.

For DECON and SAFSTOR, there are a number of activities during Stage 2 that the plant can either choose not to perform or can perform at a later date. Chemical decontamination of the primary system and creation of a nuclear island are the two main activities that several decommissioning sites have undertaken. Chemical decontamination is optional for ENTOMB1 and would not likely occur for ENTOMB2. Support systems no longer necessary to reactor operation may also be removed for all four options. Likewise, additional support systems needed for decommissioning activities may be installed at this stage for DECON, SAFSTOR, and ENTOMB1. Changes to electrical systems are common during Stage 2.

Chemical decontamination of the primary system has been performed at several facilities, resulting in a reduction of total person-rem during decommissioning activities. One facility evaluated conducted a system decontamination, aiming at significant reduced dose to workers and reduced cost, by reducing both the amount and level of contamination from disposal of contaminated piping. This chemical decontamination was performed following the removal of the steam generators, pressurizer, and reactor coolant pump motors, as well as most of the

Table 3-2. Permanently Shutdown Plants

Nuclear Plant	Reactor Type	Thermal Power	Shutdown Date [a]	Decommissioning Option[b]	Location	Fuel Status and License Termination Date
Plants Currently in Decommissioning Process						
Big Rock Point	BWR	240 MW	08/30/97	DECON	Michigan	Fuel in pool
Dresden, Unit 1	BWR	700 MW	10/31/78	SAFSTOR	Illinois	Fuel in ISFSI
Fermi, Unit 1	FBR	200 MW	09/22/72	SAFSTOR[c]	Michigan	No fuel onsite
GE-VBWR	BWR	50 MW	12/09/63	SAFSTOR	California	No fuel onsite
Haddam Neck	PWR	1825 MW	07/22/96	DECON	Connecticut	Fuel in pool
Humboldt Bay, Unit 3	BWR	200 MW	07/02/76	SAFSTOR[c]	California	Fuel in pool
Indian Point, Unit 1	PWR	615 MW	10/31/74	SAFSTOR	New York	Fuel in pool
La Crosse	BWR	165 MW	04/30/87	SAFSTOR	Wisconsin	Fuel in pool
Maine Yankee	PWR	2700 MW	12/06/96	DECON	Maine	Fuel in pool[d]
Millstone, Unit 1	BWR	2011 MW	11/04/95	SAFSTOR	Connecticut	Fuel in pool
Peach Bottom, Unit 1	HTGR	115 MW	10/31/74	SAFSTOR	Pennsylvania	No fuel onsite
Rancho Seco	PWR	2772 MW	06/07/89	SAFSTOR[c]	California	Fuel in ISFSI/Partial DECON proposed in 1997
San Onofre, Unit 1	PWR	1347 MW	11/30/92	SAFSTOR[c]	California	Fuel in pool
Saxton	PWR	28 MW	05/01/72	SAFSTOR[c]	Pennsylvania	No fuel onsite/Currently in DECON
Three Mile Island, Unit 2	PWR	2772 MW	03/28/79	Accident cleanup followed by storage	Pennsylvania	Approx 900 kg fuel onsite/ Post-defueling monitored storage
Trojan	PWR	3411 MW	11/09/92	DECON	Oregon	Fuel in pool
Yankee Rowe	PWR	600 MW	10/01/91	DECON	Massachusetts	Fuel in pool[d]
Zion, Unit 1	PWR	3250 MW	02/21/97	SAFSTOR	Illinois	Fuel in pool
Zion, Unit 2	PWR	3250 MW	09/19/96	SAFSTOR	Illinois	Fuel in pool
Terminated Licenses						
Fort St. Vrain	HTGR	842 MW	08/18/89	DECON	Colorado	Fuel in ISFSI/License terminated in 1997
Pathfinder	BWR	190 MW	09/16/67	SAFSTOR	South Dakota	No fuel onsite/License terminated in 1992
Shoreham	BWR	2436 MW	06/28/89	DECON	New York	No fuel onsite/License terminated in 1995

(a) The shutdown date corresponds to the date of the last criticality.
(b) The option shown in the table for each plant is the option that has been officially provided to NRC. Plants in DECON may have had a short (1 to 4 yr) SAFSTOR period. Likewise, plants in SAFSTOR may have performed some DECON activities or may have transitioned from the storage phase into the decontamination and dismantlement phase of SAFSTOR.
(c) These plants have recently performed or are currently performing the decontamination and dismantlement phase of SAFSTOR.
(d) Licensee is in process of transferring fuel to dry storage in onsite ISFSI.

auxiliary piping. At a second facility evaluated, a chemical decontamination was considered necessary to keep doses within previously issued EAs. The chemical decontamination was performed early in the decommissioning process to allow dismantling to proceed unimpeded. Other plants, both operating and permanently shutdown, have also performed chemical decontamination.

Some plants have also created nuclear islands, which reduce the scope of the required safeguards and security systems to only the fuel storage facilities and isolate the spent fuel so decontamination and dismantlement can proceed on the balance of the facility without the potential for affecting the spent fuel. Creating a nuclear island may involve installing an electrical power supply at the spent fuel pool, installing or modifying chemistry controls, designing and constructing a new heat removal system, and moving or installing new security-related equipment. For plants going into SAFSTOR, creation of a nuclear island is primarily a cost savings, but for plants in active decontamination and dismantlement, work activities may be done more conveniently when workers are not constrained by security requirements. ENTOMB2 would not benefit from the "nuclear island" concept.

Environmental impacts may vary at each site, depending on the activities and the timing of the activities performed. Examples of impacts include activities such as chemical decontamination, which result in the use of small quantities of water and produce LLW as well as some liquid effluents that would not be released unless they are below the limits allowed by the regulations in 10 CFR Part 20. Smaller amounts of waste will likely be generated during the creation of a nuclear island or the rewiring of a facility.

Stage 3 in Figure 3-3 involves decontamination and dismantlement of the plant for DECON, SAFSTOR, and ENTOMB1. For ENTOMB2, Stage 3 involves dismantlement of all radioactively contaminated SSCs external to the reactor building and placement of these SSCs in the reactor building, followed by lowering the ceiling to the D-rings (PWRs) or refueling floor (BWRs). For both ENTOMB options, it includes installation of concrete and engineered barriers and development of the license termination monitoring program. For those sites that have a SAFSTOR period, Stage 3 includes the storage time. The decontamination and dismantlement activities performed for SAFSTOR can occur before, after, or during the storage period. For the SAFSTOR period, Stage 3 can be from just a few years to about 54 years. For a site going straight through the DECON option, the time for Stage 3 would be expected to take between 3½ and 10 years. For either ENTOMB option Stage 3 would be expected to take 2 to 4 years

The greatest variability in the decommissioning process is seen in Stage 3 and is related to dismantlement. Every plant that has completed decommissioning or has started dismantlement has performed the activities in different ways and at different times during the decommissioning

process. Two examples of large-component removal are at Rancho Seco and Trojan. Rancho Seco has started its dismantlement on the secondary side, removing the moisture separators, diesel generators, steam piping, and related components. Dismantlement of the equipment in the auxiliary building was also initiated. Plans for large-component removal are still in process. The primary issues related to decisions on large-component removal are how to transport the components. Because there are no convenient waterways for transport, the large components from Rancho Seco will have to be shipped by both road and rail, which will require segmentation or cutting up the larger components. Trojan took a different approach to dismantlement, based on the ability to ship by barge and the availability of disposal at Hanford. Trojan removed its four steam generators and pressurizer, pumped grout into them, and shipped them by barge for burial at Hanford. Following that activity, the reactor vessel and internals were removed whole, filled with grout, welded closed, and shipped. For Trojan, removing and shipping these large components as whole units saved millions of dollars and significantly reduced dose to workers.

Stage 4 of decommissioning is license termination. Activities for this stage, which are similar for all options, include final site characterization, final radiation survey submission of final license termination plan, and final site survey. The ENTOMB options would include both a partial site release and a site monitoring program.

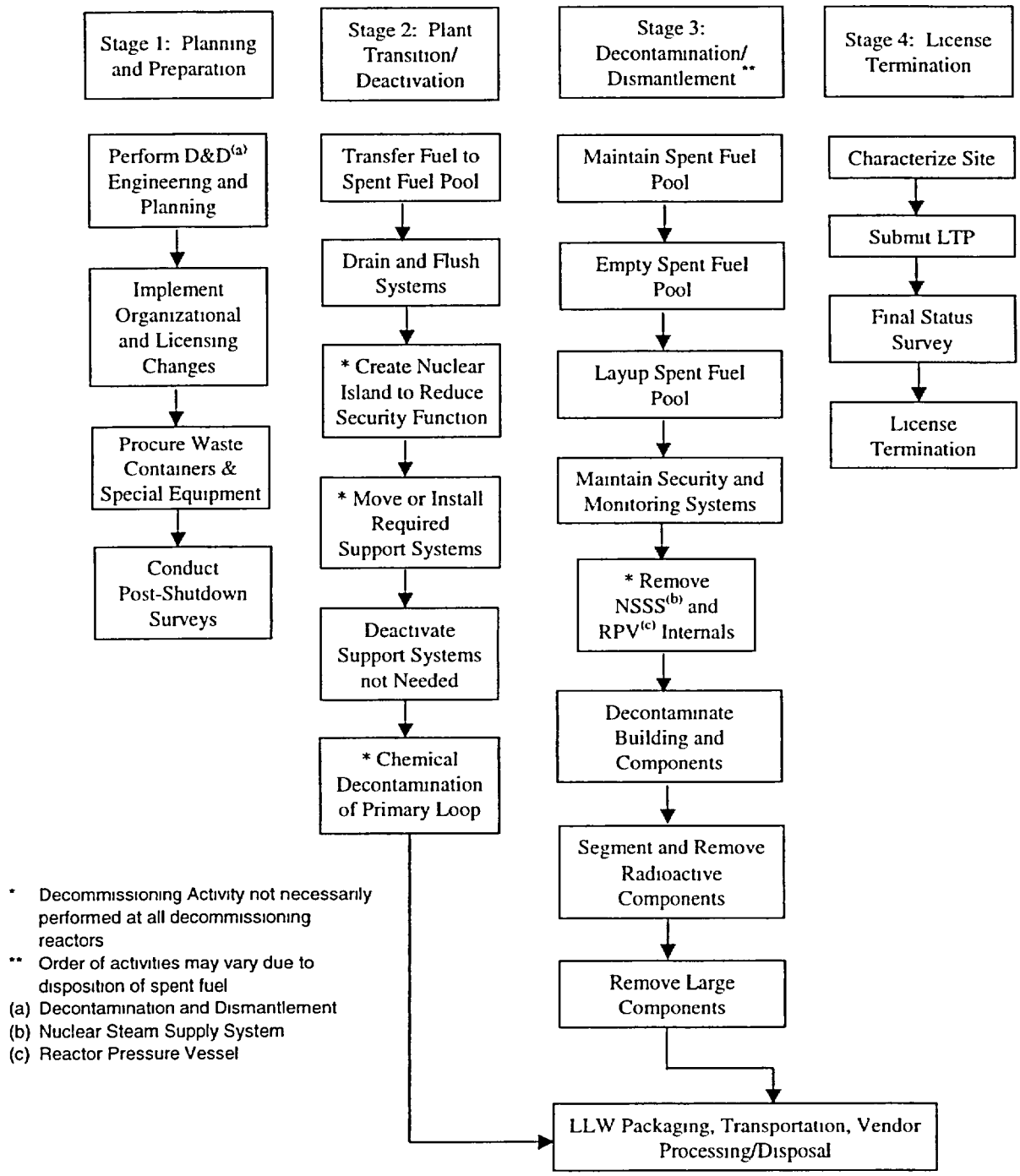

Figure 3-3. Reactor Decommissioning Process - DECON or SAFSTOR

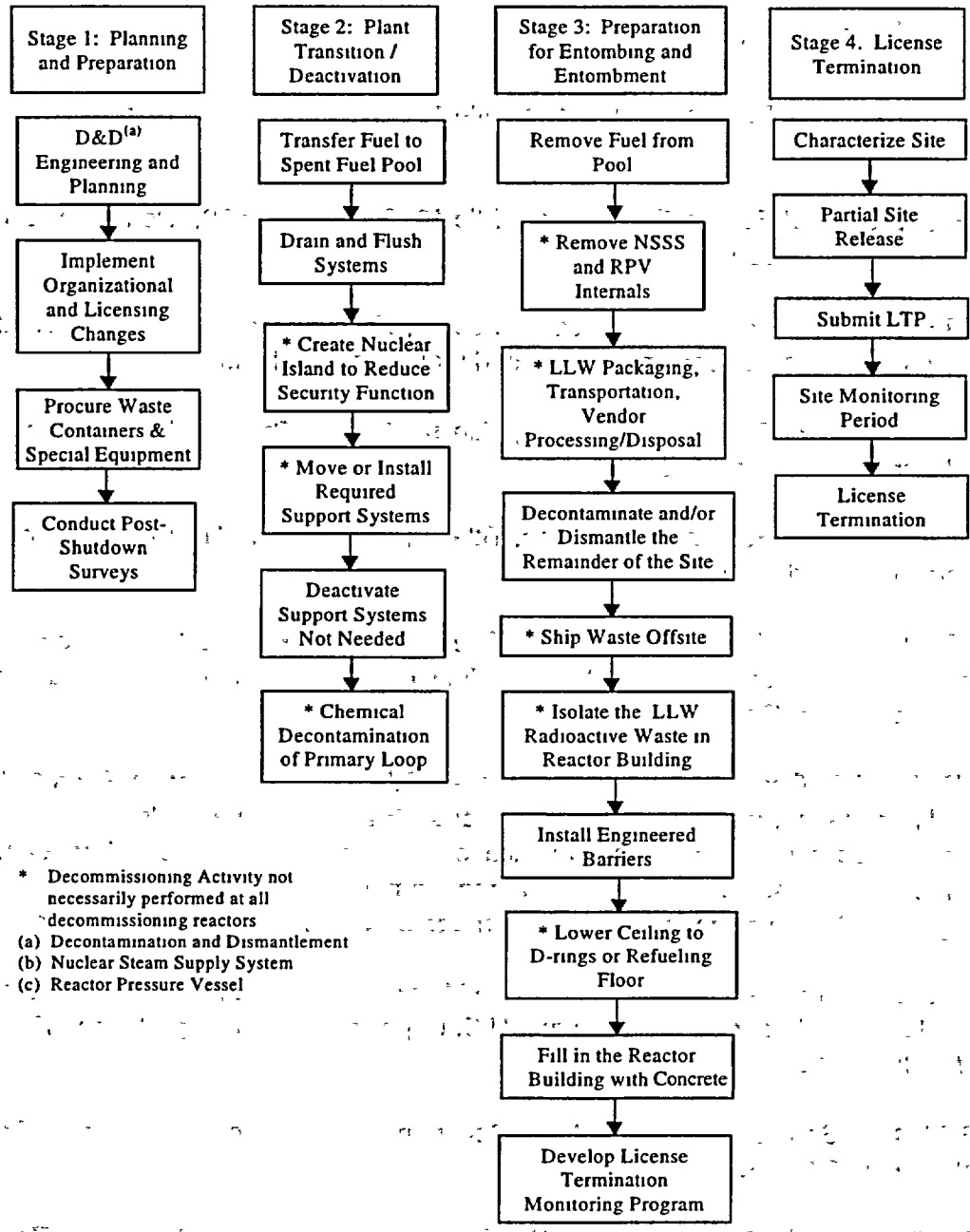

Figure 3-4. Reactor Decommissioning Process - ENTOMB

3.4 References

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4.0 Environmental Impacts of Decommissioning Permanently Shutdown Nuclear Power Reactors

This section discusses the environmental impacts of decommissioning permanently shutdown nuclear power reactor facilities. Section 4.1 defines the terms used to describe environmental impacts of decommissioning activities. Section 4.2 briefly describes the process that was used to identify the environmental impacts of the decommissioning activities. The environmental impacts, including the staff's conclusions, are discussed in Section 4.3.

4.1 Definition of Environmental Impact Standards

This Supplement provides a measure of (1) the significance and severity of potential environmental impacts and (2) the applicability of these decommissioning impacts to a variety of facilities, both permanently shutdown and operating. The significance of each environmental impact is described as SMALL, MODERATE, or LARGE. The applicability of these impacts to a class of plants or site characteristics is categorized as either generic or site-specific. The following sections define the significance and applicability terms used in the Chapter 4 analyses.

4.1.1 Terms of Significance of Impacts

For decommissioning, the staff is using a standard of significance derived from the Council on Environmental Quality (CEQ) terminology for "significantly"[(a)] (40 CFR 1508.27, which considers "context" and "intensity"). The NRC has defined three significance levels: SMALL, MODERATE, and LARGE.

SMALL – Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts in this Supplement, the NRC has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

(a) The National Environmental Policy Act of 1969 (NEPA) requires consideration of both *context* and *intensity* when determining the significance of an environmental impact. **Context** means that the significance of an action must be analyzed in several contexts, such as society as a whole (human, national), the affected region, the affected interests, and the locality. Significance varies with the setting of the proposed action. **Intensity** refers to the severity of the impact and depends on many different factors, such as the unique characteristics of the site and the degree to which the proposed action affects public health or safety or may establish a precedent.

MODERATE – Environmental impacts are sufficient to alter noticeably, but not to destabilize, important attributes of the resource.

LARGE – Environmental impacts are clearly noticeable and are sufficient to destabilize important attributes of the resource.

The discussion of each environmental issue in this Supplement includes an explanation of how the significance level was determined. In determining the significance level, the staff assumed that ongoing mitigation measures would continue (including those mitigation measures implemented during plant construction and/or operation) during decommissioning, as appropriate. Additionally, the staff has assumed that a licensee will obtain all relevant permits and appropriate consultations, will continue to comply with the conditions of those permits or consultations, and will use appropriate best management practices (BMPs) to minimize impacts of decommissioning activities. Benefits of additional mitigation measures during or after decommissioning are not considered in determining significance levels.

The cumulative impacts of all activities were assessed. Cumulative impacts are incremental impacts of the decommissioning activity when added to other past, present, and reasonably foreseeable future actions at the licensed site.

4.1.2 Terms of Applicability of Impacts

In addition to determining the significance of environmental impacts, this Supplement includes a discussion of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. Each environmental issue is assigned to one of two categories:

- Generic – For the issue, the analysis reported in this Supplement presents the following:

  (a) Environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues to plants of a specific size, a specific location, or having a specific type of cooling system or site characteristics, and

  (b) A single significance level (i.e., SMALL, MODERATE, or LARGE) has been assigned to the impacts, and

  (c) Mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely not to be sufficiently beneficial to warrant implementation.

- Site-specific – For the issue, the analysis reported in this Supplement has shown that one or more of the generic criteria was not met. Therefore, additional plant-specific review is required. An example of a site-specific issue is threatened and endangered species.

For many issues, similar activities may be performed either on the plant site or offsite. In several cases, the conclusions as to generic or site-specific are different for these locations. In this Supplement, the term "operational areas" are the areas within the protected area fences, the intake and discharge structures, the cooling system, and other site structures, and the associated paved, graveled, and maintained landscaped areas. The operational area is defined as the portion of the plant site where most or all of the site activities occur, such as reactor operation, materials and equipment storage, parking, substation operation, facility service and maintenance, etc.

4.2 Evaluation Process

This section briefly describes the process that the staff used to determine the environmental impacts from decommissioning nuclear power facilities. For a detailed description of this process, see Appendix E, "Evaluation Process for Identifying the Environmental Impacts of Decommissioning Activities." Figure 4-1 is a flowchart showing the evaluation process. Figure 4-1 identifies activities that occur during decommissioning and shows whether the activities affect any of the identified environmental issues. The environmental issues analyzed by the staff are the following: onsite/offsite land use, water use, water quality, air quality, aquatic ecology, terrestrial ecology, threatened and endangered species, radiological, radiological accidents, occupational issues, cost, socioeconomics, environmental justice, cultural impacts, aesthetic issues, noise, transportation, and irretrievable resources. To analyze each issue, the staff used the data obtained from previous studies and environmental reviews, information obtained during site visits and provided by the plants undergoing decommissioning, and information from currently operating nuclear power facilities. The staff's assessment includes an assessment of cumulative impacts. For discussions of cumulative impacts, the NRC used the terminology defined in 40 CFR 1508.7. "Cumulative impact is the impact on the environment, which results from the incremental impact of the action (in the case of this Supplement, that is decommissioning activities) when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." The staff examined the cumulative impacts of decommissioning activities and other past, present, and reasonably foreseeable future activities at the licensed sites.

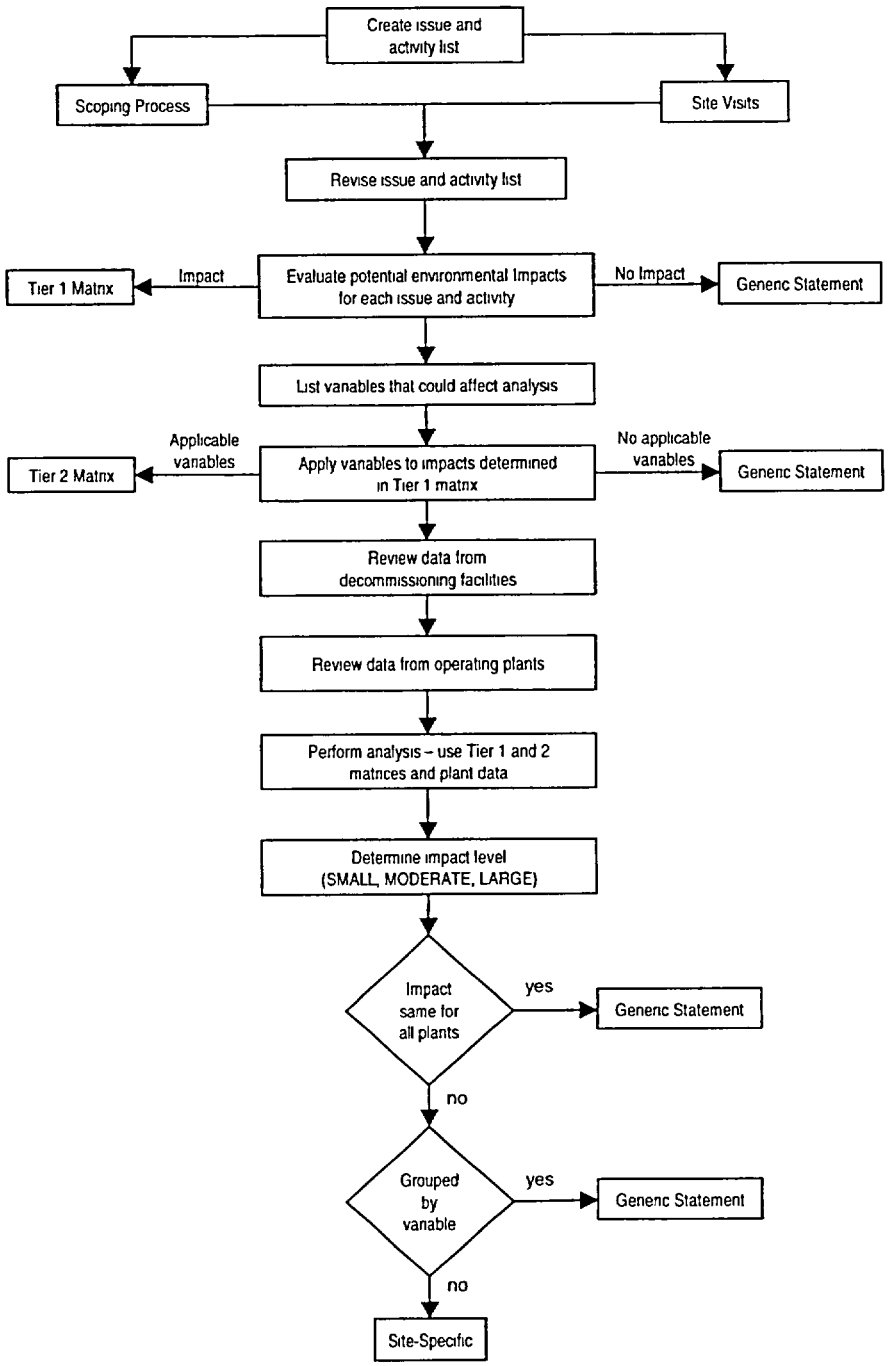

Figure 4-1. Environmental Impact Evaluation Process

Previous or anticipated decommissioning activities at the fast breeder reactor (FBR) or high-temperature gas-cooled reactor (HTGR) have not and are not expected to result in impacts that are different from those found at other nuclear reactor facilities.

After analyzing each issue, the staff determined the nature of the impact (site-specific or generic) and the significance level of the environmental impact (SMALL, MODERATE, or LARGE). This evaluation resulted in a range of impacts for each issue that may be used for comparison by licensees that are or will be decommissioning their facilities.

4.3 Environmental Impacts from Nuclear Power Facility Decommissioning

The following sections are organized by issue and discuss environmental impacts. Each section has four parts:

(1) Regulations – Identifies statutes, regulations, or limits relevant to the issue.

(2) Potential impacts from decommissioning activities - Discusses possible impacts related to the issue and defines, where appropriate, the terms detectable and destabilizing for the issue.

(3) Evaluation – Describes analysis and professional judgement used to estimate whether an activity or group of activities is likely to make a noticeable impact on the environment, considering the available data. If an impact is likely, existing and additional mitigation measures that can be taken to avoid the impact are evaluated. If an impact cannot be avoided, a determination is made as to whether the impact is likely to destabilize the resource.

(4) Conclusion – Provides the staff's conclusion on significance (SMALL, MODERATE, LARGE) and applicability (generic or site-specific) of impacts to the issue.

The conclusions from this chapter are summarized in two tables in Appendix H. Table H-1 provides a list of decommissioning activities that have been determined to have no environmental impacts. These activities can be performed by licensees without further analysis. Table H-2 provides a comprehensive summary of the decommissioning activities and associated environmental issues that have been determined by the staff to have potential environmental impacts. Providing they fall within the range of the impacts identified, these activities can be performed with no further analysis by the licensee.

4.3.1 Onsite/Offsite Land Use

Nuclear power facilities are large physical entities, of which 20 to 40 ha (50 to 100 ac) may actually be disturbed during plant construction. Other land commitments can amount to many thousands of hectares for transmission line rights-of-way (ROWs) and cooling lakes. Farming and other types of agricultural land use occur on some nuclear reactor facility sites. Some utilities have designated portions of their sites for land uses such as recreation, management of natural areas, and wildlife conservation.

4.3.1.1 Regulations

Nuclear power facilities that began initial operation after the promulgation of the National Environmental Policy Act of 1969 (NEPA; 42 USC 4321 to 4347) or the Endangered Species Act of 1973 (ESA; 16 USC 1531 to 1544) were sited and are operated in compliance with these statutes. Any modifications to the facilities after the effective dates of these acts and others (see Appendix L-2) must be in compliance with the requirements of these statutes. The ESA applies to both terrestrial and aquatic biota. The individual States may also have requirements regarding threatened and endangered species; the State-listed species may vary from those on the Federal lists. In addition, activities such as decommissioning must take into account and avoid disturbance of historic and archeological sites, and American Indian grave sites. (Native American Graves Protection and Repatriation Act of 1990; 25 USC 3001 et seq.)

4.3.1.2 Potential Impacts of Decommissioning Activities on Land Use

Temporary changes in onsite land use could occur at a nuclear reactor facility site during decommissioning. Temporary changes may include addition or expansion of staging and laydown areas or construction of temporary buildings and parking areas. These temporary changes in onsite land use do not change the fundamental purpose or use of the reactor site. The major activities that may influence onsite land use are removal of large components, such as the reactor vessel and steam generators, structure dismantlement, and low-level waste (LLW) packaging and storage. Table E-3 in Appendix E describes the activities that occur during decommissioning that influence offsite and onsite land use.

The need for land during decommissioning is affected by the site layout. Most sites have sufficient area existing within the previously disturbed area (whether during construction or operation of the site) and, therefore, no additional land needs to be disturbed. The major activities projected to occur for decommissioning that are expected to temporarily require land include activities such as staging of equipment and removal of large components. In addition, the large number of temporary workers needed to accomplish the major decommissioning

activities may require that temporary facilities be installed for onsite parking, training, site security access, office space, change areas, fabrication shops, mockups, and related needs.

Some activities, such as widening and rebuilding access roads or creating or expanding gravel pits for building roads, may occur offsite. The experience of plants that are being decommissioned has not included any needs for additional land offsite.

Changes to land use are considered detectable if changes in the area's general land-use pattern result. The change would be destabilizing if large-scale new development and major changes in the land-use pattern occur. For example, a new local access route through rural land to the plant would represent a detectable, but not destabilizing, change in many localities.

4.3.1.3 Evaluation

Nuclear power facility site areas range from 34 ha (84 ac) for the San Onofre Nuclear Generating Station in California to 9,700 ha (24,000 ac) for the Turkey Point Plant in Florida. According to NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NRC 1996), of the operating reactors, 29 site areas range from 200 to 400 ha (500 to 1000 ac), with an additional 13 sites ranging from 400 to 800 ha (1000 to 2000 ac). Thus, almost 60 percent of the plant sites encompass 200 to 800 ha (500 to 2000 ac). Larger land-use areas are associated with plant cooling systems that include reservoirs, artificial lakes, and buffer areas.

The nuclear reactor facilities being decommissioned are predominantly on the smaller sites, primarily because the older, smaller reactors have already permanently ceased operation. Only 6 out of 21 sites (29 percent) were between 400 and 800 ha (100 to 2000 ac); 6 (29 percent) were larger than 800 ha (2000 ac); and the rest (43 percent) were smaller than 400 ha (1000 ac) (see also Appendix F).

Almost all of the sites undergoing active decommissioning are utilizing areas used during construction. Land requirements for decommissioning activities appear to be well within the range of land requirements for activities during major outages that occur in the course of normal operations. There does not appear to be any significant differences in land use between plants using SAFSTOR or DECON options. There is no experience with either ENTOMB option with commercial power reactors in the United States, although there is some entombment experience with former U.S. Department of Energy (DOE) scientific and nuclear materials production reactors. Because of the potential need for large amounts of concrete and aggregate for ENTOMB2, it is possible that a concrete batch plant might be set up onsite. There might not be adequate room within the operational area at some of the sites for such a

facility, but it is likely that the impact of such a disturbance would be temporary and minor. Smaller amounts of concrete and aggregate would likely be required for the ENTOMB1 option.

Many of the facilities currently being decommissioned are relatively small reactors and located on small areas of land. However, a comparison of the land-use needs shows that many activities require the same amount of land for reactors whether the reactor size is small or large. It does not appear that land use will be significantly greater for future decommissioning at remaining sites. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in onsite or offsite land-use impacts that are different from those found at other nuclear reactor facilities. There has been limited experience with multi-unit sites. Multiple-plant sites that are being decommissioned may be able to economize on space by reusing laydown areas.

Large-component removal is similar in its land requirements to major component replacement activities, such as steam generator replacement and refurbishment activities. Based on previous experience with steam generator replacement at a pressurized water reactor (PWR), it was estimated in NUREG-1437 that ~1 to 4 ha (~2.5 to 10 ac) of land may be needed to accommodate laydown, staging, handling, temporary storage, personnel processing, mockup and training, and related needs (NRC 1996). The impacts of steam generator or other major component removal during decommissioning should be similar or less. Generally, this land has been previously disturbed during the construction of the facility. Once the major decommissioning activities are completed, this land could be returned to its previous uses.

Based on current information collected at sites using the DECON and SAFSTOR options, decommissioning activities that affect offsite land use are not expected unless major upgrades to transportation links are required. It may be necessary to establish or re-establish road, rail, or water transportation links into the site for the purpose of bringing in equipment (especially large equipment), removing large components, and shipping offsite certain chemicals, waste concrete and metal, or other materials created, contaminated, or used in the decontamination and dismantlement processes. In such cases, offsite land-use impacts may be detectable or destabilizing. Additional attention to transportation routing and to the organization of activities to minimize the need for transportation re-establishment or upgrade may be able to reduce the impacts to undetectable levels. The ENTOMB options may require additional land offsite for a concrete batch plant, but in most cases the land use for this activity will be temporary, though detectable.

4.3.1.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on land use, including comments received on the draft of Supplement 1 of NUREG-0586. For

facilities having only onsite land-use changes as a result of large component removal, structure dismantlement, and LLW packaging and storage, the impacts on land use are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that the potential impacts to land use onsite are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

If changes in land use beyond the site boundary are anticipated, the impacts may or may not be detectable or destabilizing, depending on the site-specific conditions, and cannot be predicted generically. Therefore, the staff has concluded that if new land uses beyond the site boundary are anticipated, the magnitude of the potential impact may be SMALL, MODERATE, or LARGE, depending on the nature, size, and permanence of the disturbance to existing land use and must be determined through a site-specific analysis.

4.3.2 Water Use

Nuclear reactor facilities are usually located near or adjacent to significant water bodies (aquifers, rivers, lakes, etc.) that are important to the region. Operating nuclear reactor facilities use water from multiple sources. For example, water from an adjacent lake might provide cooling water, whereas potable water may come from groundwater wells located onsite. Reactor cooling is the greatest use of water at an operating reactor. Other uses include waste treatment, potable water, process water, and site maintenance.

4.3.2.1 Regulations

Water use at nuclear reactor facilities is regulated by State- and locally-issued permits. Most States require permits for surface water or groundwater withdrawals.

4.3.2.2 Potential Impacts of Decommissioning Activities on Water Use

Cessation of plant operations will result in a significant decrease in water consumption because reactor cooling is no longer required. Although water will still be required for spent fuel cooling, this demand will decrease as the fuel ages. Dewatering systems may remain active during decommissioning of a nuclear facility to control the water pathway for the release of radioactive material. Table E-3 in Appendix E lists decommissioning activities that may influence water use. These activities include fuel removal, staffing changes, large component removal, decontamination and dismantlement (using high-pressure water sprays), structure dismantlement, and entombment.

Impacts to water resources of decommissioning activities would be considered detectable if such activities result in a significant change in water supply reliability. The reliability of water supplies is impacted by a variety of factors, such as natural climatic variability and the reliability of the regional and local water-supply infrastructures. For example, an additional incremental drawdown attributable to a groundwater well at a decommissioning site may be measurable at an offsite well. However, this does not necessarily constitute a detectable change in the reliability of the water supply. It would be detectable if the offsite well is unable to withdraw its permitted volumes as a result of this increased drawdown. The impacts of decommissioning activities are considered destabilizing if they result in a permanent and/or significant loss of water supply reliability. For instance, heavy pumping of an aquifer that results in subsidence may cause a permanent loss of aquifer capacity. Another example of a destabilizing impact is a change in site drainage or stream-channel changes that would result in a detectable and significant change in the probability of flooding.

4.3.2.3 Evaluation

In general, the impact of nuclear reactor facilities on water resources dramatically decreases after plants cease operation. The flow through the condenser of an operating plant can range from 3 to 78 m^3/s (49,000 to 1,200,000 gpm) (NRC 1996), depending upon the size of plant. This operational demand for cooling and makeup water is largely eliminated after the facility permanently ceases operation. As the plant staff decreases, the demand for potable water also generally decreases. However, in a few cases staffing levels have temporarily increased above levels that were common for routine operations. For these short periods of time, commonly during the early stages of decontamination and dismantlement activities, there may be a slight increase in demand for potable water.

Most of the impacts to water resources likely to occur during decommissioning of a nuclear facility are also typical of the impacts that would occur during decommissioning or construction of any large industrial facility. For example, providing water for dust abatement is a concern for any large construction project, as is potable water usage. However, the quantities of water required are trivial compared to the quantity used during operations. There are some activities affecting water resources and decommissioning nuclear facilities that are different from other industrial non-nuclear activities. The demand for water for spent fuel maintenance (approximately 200 to 2000 L [50 to 500 gal.] of water per day, depending on the size and location of the pool) and wet decontamination methods (such as a full flush of the primary system or hydrolasing embedded piping in place), although not large, are unique to nuclear facilities. One facility reported using approximately 9500 to 11,000 L (2500 to 3000 gal.) of water per day for spent fuel pool spray-cooling during the summer months. Additionally, water in some of the systems or piping may continue to be used during decontamination and dismantlement to

provide shielding from radiation for workers who are dismantling structures, systems, and components (SSCs) in the vicinity. For example, 912,000 L (240,000 gal.) of water was used at one site to fill the reactor cavity in preparation for the segmentation of the reactor vessel.

Common engineering practices, such as water reuse, are used to limit water use impacts at most construction or industrial sites. However, use of some of these practices may be limited by radiological exposure considerations at decommissioning sites.

Water use at decommissioning nuclear reactor facilities is significantly smaller than water use during operation. The water use will be greater in facilities that are undergoing decontamination and dismantlement than those that are in the storage phase. During ENTOMB, water will be required as the concrete for entombment is mixed. Greater amounts of water will be needed for the ENTOMB2 option than for ENTOMB1. However, in both cases, this process would be of short duration and would not consume quantities of water in excess of those used in the construction of large buildings.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in water use impact that is different from those found at other nuclear reactor facilities.

4.3.2.4 Conclusions

The staff considered available information on the potential impacts of decommissioning on water use, including information received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on water use are neither detectable nor destabilizing. Therefore, the staff makes a generic conclusion that the potential impacts to water use are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.3 Water Quality

There are quality standards for drinking water, protection of aquatic and terrestrial habitats, and release of potential pollutants to surface and groundwater environs. Nuclear reactor facilities are usually located above aquifers or adjacent to important sources of water. Intended and accidental releases of potential pollutants may impact the quality of these waters. This section considers water quality impacts of nonradioactive material for both surface water and groundwater during the decommissioning process. Impacts from releases of radioactive material in liquid effluents are discussed in Section 4.3.8, "Radiological."

4.3.3.1 Regulations

Intentional releases of nonradioactive discharges to surface waters are regulated through the National Pollutant Discharge Elimination System (NPDES; Section 402 of the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act [CWA] [33 USC 1251 to 1387]) to protect water quality. Congress has delegated the responsibility for NPDES implementation to the U.S. Environmental Protection Agency (EPA). When the EPA determines that State programs are equivalent to the Federal NPDES program, the NPDES permitting process is delegated to the State. Generally, discharge limits specified by the NPDES permit are revisited every 5 years. Ongoing monitoring programs may be required as part of an NPDES permit.

The Resource Conservation and Recovery Act of 1976 (RCRA; 42 USC 6901 et seq.) addresses the need to investigate and clean up contamination in the event of the release of nonradioactive hazardous material not covered within the limits of the NPDES permit. As with the NPDES permitting process, Congress has delegated the responsibility for RCRA implementation to the EPA. Because NPDES permits regulate only intentional discharges to surface water, any accidental releases of nonradioactive hazardous materials that may impair water quality (surface water or groundwater) are regulated through the RCRA process. RCRA requires responsible parties to clean up environmental contaminants regardless of the time of their release. The degree of investigation and subsequent corrective action necessary to protect human health and the environment vary significantly among facilities. When the EPA determines that State programs are equivalent to the Federal RCRA program, the corrective action program is delegated to the State.

Based on an October 1978 decision by the Atomic Safety and Licensing Board, (TVA 1978a, TVA 1978b), NRC authority does not extend to matters within the jurisdiction of the EPA. More specifically, the NRC authority is limited for those matters expressly assigned to the EPA by the Federal Water Pollution Control Act Amendments of 1972. This decision would also apply to decommissioning nuclear reactor facilities.

4.3.3.2 Potential Impacts of Decommissioning Activities on Water Quality

Table E-3 in Appendix E shows the activities during decommissioning that may affect water quality. These major activities include fuel removal, stabilization, decontamination and dismantlement, and structure dismantlement. Separate assessments of potential impacts were performed for surface water and groundwater. Surface waters are most likely to be impacted either by stormwater runoff or by releases of substances during decommissioning activities.

Because water quality and water supply are interdependent, changes in water quality must be considered simultaneously with changes in water supply. For example, reduced groundwater pumping may result in a rise in the water table, providing a new pathway for contaminants currently in the subsurface. Changes in the landscape (terrain and vegetation) during decommissioning can alter the hydrologic pattern of recharge and surface-water runoff. The convergence of surface water over unvegetated soils may result in accelerated erosion and the delivery of sediment to important downstream habitat.

Impacts to water quality of decommissioning activities would be considered detectable if such activities result in a significant change in water-supply reliability. For example, stormwater erosion at a facility undergoing decommissioning may result in a measurable increase in suspended sediment in an adjacent stream or disposal of concrete onsite could alter local water chemistry of the groundwater. However, this does not constitute a detectable change in the reliability of the water supply unless the incremental change in sediment concentration precludes permitted or environmental uses. The impacts of decommissioning activities would be considered to be destabilizing on water quality if they result in a permanent or significant loss of water-supply reliability. For instance, significant increases in erosion might result in a permanent loss of benthic habitat for certain fish species.

4.3.3.3 Evaluation

Both the decommissioning activities themselves and the order in which the activities are performed control the impacts to water quality. The same activities performed in a different order can have a significantly different impact on water quality. The time between activities may also be important in assessing impacts. Delaying activities during SAFSTOR may exacerbate water-quality issues. For example, the aging of structures may create new pathways for groundwater to enter contaminated subgrade structures. This would be less of an issue for entombment of a facility, where the plant's contaminated SSCs are encased in concrete and maintained as a solid structure isolated from the environment.

Stormwater runoff and erosion control are issues faced at many industrial sites, and it is expected that after application of common BMPs, any changes in surface-water quality will be nondetectable and nondestabilizing.

All commercial nuclear power facilities have NPDES permits that regulate intentional releases of hazardous materials. Historically, unintentional releases of hazardous substances have been an infrequent occurrence at decommissioning facilities. Because the focus of decommissioning is the ultimate cleanup of the facility, considerable attention is placed on minimizing spills. Except for a few substances such as hydrocarbons (diesel fuel), such hazardous spills are

localized, quickly detected, and relatively easy to remediate. Relevant regulations are listed in Appendix L. Some of the groundwater parameters measured in the license termination plan (LTP) might also be indicators of a heretofore undetected nonradiological subsurface plume. If such indications were observed, further characterization and corrective actions would be dictated by the relevant regulations discussed in Appendix L and permits, if appropriate.

Certain decommissioning activities or options may result in changes in local water chemistry. For example, if licensees dismantle structures by demolition and disposal of the concrete rubble on the site, then there is a potential that the hydration of concrete could cause an increase in alkalinity of groundwater. The pH of interstitial (pore) water very close to the concrete rubble would remain above 10.5 for several hundred thousand years (Krupa and Serne 1988). However, as the leachate migrates away from the demolition debris, it is reasonable to expect the leachate pH to be rapidly reduced (within meters) to natural conditions due to the large buffering capacity of soils. While the leachate's pH may not be a water-quality concern, such leachate may affect the transport properties of radioactive and nonradioactive chemicals (notably metals) in the subsurface although this transport would not be detectable offsite. Surface spreading of the demolition debris over large areas may provide adequate opportunity for soils to buffer the pH to background. Because the nonradiological impacts would be nondetectable, they are considered to be generic for all sites. However, concentrated disposal of demolition debris, either within or outside of existing below-grade structures, would require below-grade compliance with RCRA guidelines. The radiological aspects of onsite disposal of slightly contaminated material would require a site-specific analysis and would be addressed at the time the LTP is submitted.

Current or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in water-quality impacts that are different from those found at other nuclear reactor facilities.

4.3.3.4 Conclusions

The staff considered available information on the potential impacts of decommissioning on nonradioactive aspects of water quality for both surface water and groundwater, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that for all facilities the impacts of decommissioning on water quality will be neither detectable nor destabilizing. Therefore, the staff makes a generic conclusion that for all facilities, the impacts on nonradioactive aspects of water quality are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.4 Air Quality

Decommissioning activities have the potential to adversely impact air quality. The activities may be direct, such as demolition of buildings, or indirect, such as transportation of decommissioning workers to and from the site. This section discusses the nonradiological impacts of decommissioning on air quality. Radiological impacts on air quality are addressed in Section 4.3.8, "Radiological."

4.3.4.1 Regulations

The purpose of the Clean Air Act (CAA) as amended (42 USC 7401 et seq.) is to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." Section 118 of the CAA, as amended, requires that each Federal agency, such as NRC, with jurisdiction over any property or facility that might result in the discharge of air pollutants, comply with "all Federal, state, interstate, and local requirements" with regard to the control and abatement of air pollution. Pursuant to the Act, the EPA established National Ambient Air Quality Standards to protect public health, with an adequate margin of safety, from known or anticipated adverse effects of regulated pollutants (42 USC 7409). Hazardous air pollutants and radionuclides are regulated separately (42 USC 7412).

EPA's regulations are found in Title 40 of the Code of Federal Regulations. The National Primary and Secondary Ambient Air Quality Standards are found in 40 CFR Part 50. The standards related to particulate matter (40 CFR 51.06 and 40 CFR 51.07) are particularly relevant to decommissioning activities. Other regulations that may cover decommissioning activities are found in 40 CFR Part 61, which deals with hazardous air pollutants such as asbestos, chlorofluorocarbons, and radionuclides; 40 CFR Part 81, which deals with designation of areas for air-quality planning purposes; and 40 CFR Part 82, which deals with protection of stratospheric ozone.

In addition, State and local agencies have developed and enforce a variety of air-quality regulations. These regulations require permits for emission sources, limit emission rates, and set maximum atmospheric concentrations for pollutants. Finally, different regulations apply to indoor air quality and worker safety.

4.3.4.2 Potential Impacts of Decommissioning Activities on Air Quality

Table E-3 in Appendix E shows activities that may have an effect on air quality. These include organizational changes, stabilization, storage preparation for SAFSTOR, decontamination and dismantlement, structural dismantlement, entombment, and transportation. The potentially adverse impacts identified include (1) degradation of air quality caused by emissions (e.g., NO_x, CO, and hydrocarbons) from internal combustion engines, (2) increased particle loading of the atmosphere caused by the movement of vehicles and equipment, demolition of structures, dismantlement of systems, and operation of concrete batch plants, and (3) alteration of other characteristics of the atmosphere (e.g., the ozone layer) by releases of gases used in plant systems (e.g., in fire suppression or refrigeration).

Air-quality impacts of emissions from internal combustion engines and changes in atmospheric particle loading can be assessed by comparison with standards set in air-quality regulations. These potential impacts are considered detectable if a decommissioning activity is likely to cause a measurable increase in the concentration of one or more regulated air pollutants that can be directly attributed to the activity. The impact is considered to be destabilizing if the impact is detectable and causes a change in the attainment status of the region. Air-quality impacts of the releases of other gases can be assessed by comparison with the magnitude of potential releases during decommissioning with the magnitude of releases of the same or similar gases from other sources.

4.3.4.3 Evaluation

Decommissioning activities that have the potential to have a nonradiological impact on air quality include:

- worker transportation to and from the site
- dismantling of systems and removing of equipment
- movement and open storage of material onsite
- demolition of buildings and structures
- shipment of material and debris to offsite locations, and
- operation of concrete batch plants.

These activities typically take place over a period of years from the time the facility ceases operation until the decommissioning is complete and the license is terminated. The magnitude and the timing of the potential impacts of each activity will vary from plant to plant, depending on the decommissioning options selected by the licensee and the status of facilities and structures at the time of license termination.

Worker transportation: Air-quality impacts of transportation of workers to and from the site are caused by emissions from the vehicles and by fugitive dust from traffic on paved and unpaved roads. Consequently, the impacts can be estimated directly from the size of the work force. Experience with decommissioning indicates that for most sites the onsite work force tends to decrease from the time that plants cease operation until decommissioning is complete. There are occasional increases during specific decontamination and dismantlement activities. However, the work force during decommissioning is smaller than the construction work force and the work force during refueling outages, and almost always smaller than the work force during facility operation.

Assuming that neither the mix of vehicles used for worker transportation nor the vehicle occupancy is different during decommissioning than during plant construction or operation, emissions from vehicles and fugitive dust associated with traffic is expected to decrease during the decommissioning period. These decreases are expected to improve air quality rather than degrade it. Consequently, the change in air quality associated with changes in worker transportation during decommissioning should not be detectable or destabilizing at any site.

Dismantling systems and removing equipment: Air-quality impacts of dismantling systems and removing equipment may be caused by the generation and release of particulate matter associated with the physical activities of dismantling and by the release of gases from the systems (for example, refrigeration systems and fire-protection systems).

The predominant potential effluent from system dismantling and removal of equipment will be particulate matter and fugitive dust. This material will generally be released in and remain within buildings and other structures because most decommissioning activities associated with dismantling systems and removing equipment will be conducted inside the containment, auxiliary, and fuel-handling buildings. These buildings have systems to minimize airborne contamination, such as whole-building air filtration. Filtration systems control the release of particulate matter to the environment. These systems, which are typically maintained and periodically operated during decommissioning, reduce the impact of airborne particulate material. Where filtration systems are not in place to control particulate releases, temporary systems can be established, as needed. Special air-ventilation pathways may be established before the start of a SAFSTOR period to ensure that air ventilates from the building through

high efficiency particulate air (HEPA) filters. It is unlikely that particulate matter released to the environment as a result of system dismantlement and equipment removal will be sufficient to be detectable offsite. Special precautions are required for worker protection where hazardous materials such as asbestos may become airborne, as discussed in Section 4.3.10, "Occupational Issues."

Various systems associated with reactors contain gases that are of environmental concern. For example, some gases used in refrigeration systems and fire-suppression systems have been identified as ozone-depleting compounds. Venting of these gases to the atmosphere is prohibited by law. Standard methods exist to purge systems with these gases and limit releases to the environment to insignificant quantities. Other fire suppression and refrigeration systems may contain greenhouse gases. The quantities of these gases at a nuclear plant are generally small in comparison with the quantities of greenhouse gases released hourly by a fossil-fuel combustion plant used for heating or power generation. The impacts of ozone-depleting and greenhouse gases are global rather than local. Therefore, it is unlikely that releases of ozone-depleting or greenhouse gases during decommissioning of any nuclear power plant will be detectable or destabilize the environment.

Movement and open storage of material onsite: Movement of equipment and open storage of materials onsite during decommissioning are similar to activities during construction or demolition of an industrial facility. The air-quality impacts of the movement of equipment and open storage of materials onsite are primarily associated with fugitive dust. Movement of equipment outside of the buildings may generate fugitive dust. Movement of equipment may also alter the size distribution of particles on the ground, making the particles more susceptible to suspension by the wind. Mitigation measures will be taken to minimize dust to comply with local air-quality regulations. Common mitigation measures include watering and other soil stabilization measures, such as spraying sealants on the area and seeding. Therefore, it is unlikely that the movement of equipment and open storage of materials will be detectable or destabilize regional air quality.

Demolition of buildings and structures: Once decontamination has been completed, the demolition of buildings and other structures at a nuclear power plant is similar to demolition of buildings and structures at industrial facilities. Demolition of buildings and major structures may cause a temporary increase in fugitive dust from the site. Fugitive dust from demolition of buildings and structures will involve large particles that will settle to the ground quickly. Demolition will generally be limited to a small number of short-duration events. Mitigation measures will be used to minimize dust. Therefore, it is unlikely that the fugitive dust from demolition of buildings and structures will be detectable or destabilize air quality.

If residual contamination is present at the time of demolition, then the demolition of buildings and structures must be conducted using techniques that keep releases of contaminated material within regulatory limits. For purposes of assessing radiological impacts, impacts are of small significance if doses and releases do not exceed limits established by the Commission's regulations.

Shipment of material and debris to offsite locations: Dismantled equipment, material, and debris from decommissioning are typically removed from the site as decommissioning progresses. The number of shipments required during the decommissioning period depends on the method of transportation and the decommissioning option chosen. Although the number of shipments may be relatively large, the decommissioning period extends over several years. As a result, the number of shipments per day is small. Current experience is that there is an average of less than one shipment per day of LLW from the plant (see Section 4.3.17, "Transportation"). Therefore, it is unlikely that the emissions from a shipment or a small number of shipments per day would be detectable or destabilize local or regional air quality at any nuclear power plant undergoing decommissioning.

Operation of a concrete batch plant: The ENTOMB options will require a large amount of concrete and aggregate. Unloading, movement, and dispensing of the materials that make concrete result in fugitive dust in the vicinity of concrete batch plants. Most of the dust is associated with unloading dry cement at the concrete batch plant and loading mixers or trucks. This dust tends to consist of large particles that settle out of the air quickly. As a result, dust associated with concrete batch plant operations is likely to be localized near the concrete batch plant. There will also be emissions from heavy equipment at concrete batch plants and vehicles used to transport concrete from the concrete batch plant to the entombment site. The likely impacts of these emissions will be smaller than those from dust.

There are a number of mitigation measures that can be used to control dust. Dust control measures commonly used at concrete batch plants include enclosure of dumping and unloading areas and conveyors, use of filters, and use of water sprays. There would be no significant difference between a concrete batch plant used in the ENTOMB option and a batch plant used for any other major construction activity. Therefore, the staff considers it unlikely that the environmental impacts of operation of a concrete batch plant for a plant undergoing entombment would be detectable or destabilize air quality.

In summary, the most likely impact of decommissioning on air quality is degradation of air quality by fugitive dust. Fugitive dust during decommissioning should be less than during plant construction because the size of the disturbed areas is smaller, the period of activity is shorter, and paved roadways may exist. Use of BMP, such as seeding and wetting, can be used to

minimize fugitive dust. During demolition activities, some particulate matter in the form of fugitive dust may be released into the atmosphere, but much of this fugitive dust consists of large particles that settle quickly. To date, licensees decommissioning nuclear reactor facilities have taken appropriate and reasonable control measures to minimize fugitive dust. No anticipated new methods of conducting decommissioning and no peculiarities of operating plant sites are anticipated to affect this pattern.

The selection of the decommissioning option (DECON, SAFSTOR, ENTOMB1, or ENTOMB2) is more likely to affect the timing of air-quality impacts than the magnitude of the impacts. Immediate decontamination and dismantlement of the facility (DECON) results in impacts earlier than the SAFSTOR option, in which most decommissioning activities are postponed to permit residual activity in the plant to decay. ENTOMB1 and ENTOMB2 may include the dismantlement of structures outside of containment and, thus, could result in air-quality impacts related to fugitive dust that would be the same as or greater than during DECON.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in air-quality impacts that are different from those found at other nuclear facilities.

4.3.4.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on air quality, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on air quality are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on air quality are SMALL. The staff has considered mitigation and concludes that current and commonly used measures are sufficient and no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.5 Aquatic Ecology

Aquatic ecology issues incorporate all of the plants, animals, and species assemblages in the rivers, streams, oceans, estuaries, or any other aquatic environments near a nuclear power facility. Aquatic ecology also includes the interaction of those organisms with each other and the environment.

4.3.5.1 Regulations

Federal laws that are included within a NEPA evaluation of aquatic ecology issues include the CWA, the ESA of 1973, the Fish and Wildlife Coordination Act (16 USC 661 to 667c), and NEPA. Although some biota may be affected by a number of decommissioning activities, full consideration is usually reserved for the more important aquatic resources, which may be either individual species or habitat-level resources. Some activities, such as removal of in-stream or shoreline structures, may require permits from other agencies.

4.3.5.2 Potential Impacts of Decommissioning Activities on Aquatic Ecological Resources

Table E-3 in Appendix E identifies decontamination and dismantlement and structural dismantlement as activities that may affect aquatic ecology. Aquatic ecological resources may be impacted during the decommissioning process via either the direct or the indirect disturbance of plant or animal communities near the plant site. Direct impacts can result from activities such as the removal of shoreline or in-water structures (i.e., the intake or discharge facilities), the active dredging of a stream, river, or ocean bottom, or the filling of a stream or bay while indirect impacts may result from effects such as runoff. During decommissioning, aquatic environs at the plant site may be disturbed for the construction of support facilities, such as to build a dock for barges or to bridge a stream or aquatic area. Additionally, aquatic environs away from the plant site may be disturbed to upgrade or install new transportation systems (e.g., a new rail line to support large component removal) or to install or modify transmission lines. In most cases, aquatic disturbances will result in relatively short-term impacts and the aquatic environs will either recover naturally or impacts can be mitigated. Minor impacts to aquatic resources could result from sediment runoff generation due to ground disturbance and surface erosion and runoff. Impacts may occur if shoreline or in-water structures, such as the intake or discharge facilities and pipes, are removed. These impacts will typically be temporary and will not be detectable nor will they destabilize important attributes of the resource. It is important that shoreline or in-water structure removal is managed in a manner that does not result in the establishment of nonindigenous or noxious plants and animals to the exclusion of native species.

If decommissioning does not include removal of shoreline or in-water structures, very little aquatic habitat is expected to be disturbed during decommissioning. Thus, practically all aquatic habitat that was used during regular plant operations or, at a minimum, was not previously disturbed during construction of the site will not be impacted. If all activities are confined to the plant operational areas, impacts are expected to be minor and would primarily result from increased sediment from physical alterations of the site. If no disturbances occur

beyond the regular operational areas of the site, it is expected that the impact to aquatic resources will be nondetectable, nondestabilizing, and easily mitigated.

In some cases, the aquatic habitats that were originally disturbed during the construction of the site will continue to be of low habitat quality at the time of site decommissioning, even beyond the normal operations boundaries. However, important resources could either develop on the site or colonize the area disturbed by the construction. If a decommissioning activity results in the "removal" of species from an area (e.g., if a commercial or recreational fishery is no longer possible), this may be detectable. Reworking the ground surface during construction could alter the surface-drainage patterns such that wetlands on the original construction site may no longer support an aquatic community. If this is an important local or regional resource, it may be considered destabilizing.

4.3.5.3 Evaluation

The primary factors that must be considered in evaluating the potential for adverse impacts in areas previously disturbed by construction include the quantity of habitat to be disturbed, the length of time since initial disturbance, and the successional patterns of the aquatic communities (especially nuisance species). Most of the important aquatic ecological resources are not likely to occur on most plant sites. If they do occur, the decommissioning activities can probably be planned to avoid or minimize detectable and destabilizing effects.

Two decommissioning activities may result in impacts to the aquatic environment: removal of structures from the shoreline or in-water environment and removal of contaminated soil from the site (the latter applies only if the soil is in or near an aquatic environment).

Additionally, dredging and modification of barge loading facilities may result in impacts to aquatic ecological resources. Periodic permitted, maintenance dredging of the barge unloading facility is not expected to result in long term detectable or destabilizing impacts to the aquatic environment. Impacts to the aquatic resources would be within the bounds of the generic assessment. However, a significant expansion of the barge unloading facility necessary to accommodate, for example, a large shipping package such as a reactor vessel would require a site specific assessment. The environmental assessment may be performed by the U.S. Corps of Engineers as part of the review to permit the enlargement of the barge unloading facility.

In most cases, the aquatic environment required to support the decommissioning process is relatively small and is normally a very small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the boundaries of the site operational areas and typically are immediately adjacent to the reactor, auxiliary, and control

buildings. Discharge permits to the aquatic environment for operation are almost always greater than planned or realized during decommissioning. In almost all cases examined, licensees expect to restrict activities to previously disturbed areas and operate within the limits of operational permits.

The potential for adverse impacts are likely to be nondetectable or nondestabilizing regardless of the decommissioning option selected. The activity most likely to result in impacts to aquatic environments is specific to removal of shoreline or in-water structures. The decision to conduct these activities would not be dependent on the decommissioning option. The only option where shoreline or in-water structure removal appears to be guaranteed is for those plants where return to a "Greenfield" is desired or required.

When there is a decommissioning activity outside the operational area, the significance of the potential impacts are more difficult to define and will depend on site-specific considerations. The primary factors that need to be considered include the total acreage of habitat to be disturbed, and the overall importance of the plant or animal species or communities to be disturbed. If important resources may be affected by the decommissioning activities, the impacts may be detectable and destabilizing.

Current or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in aquatic ecology impacts that are different from those found at other nuclear reactor facilities.

4.3.5.4 Conclusion

The staff has considered available information on the potential impacts of removing facility structures or contaminated soil from or near the aquatic environment on the aquatic ecological resources, including comments received on the draft of Supplement 1 of NUREG-0586. For facilities where disturbance of lands beyond the operational areas is not anticipated, the impacts on aquatic ecology are not detectable or destabilizing. The staff believes that activities within operational areas including the removal of shoreline or in-water structures, will have minimal impact on aquatic resources provided all applicable BMPs are employed and required permits are obtained. Therefore, the staff makes a generic conclusion that for such activities, the potential impacts to aquatic ecology are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions and cannot be predicted

generically. Therefore, the staff concludes that if disturbance beyond the operational areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE, and must be determined through site-specific analysis.

4.3.6 Terrestrial Ecology

Terrestrial ecology considers all of the plants, animals, and species assemblages in the vicinity of the nuclear power facility as well as the interaction of those organisms with each other and the environment. Evaluations of impacts to terrestrial ecology are usually directed at important habitats and species, including plants and animals that are important to industry, recreational activities, the area ecosystems, and those protected by endangered species regulations and legislation. Federally listed threatened and endangered species, and designated critical habitat for such species, are addressed in a separate section of this Supplement (Section 4.3.7). There are also many species identified by State agencies as endangered or threatened, and potential impacts to such species should be evaluated and mitigated, as appropriate. Important habitat resources include (but are not limited to) wetlands, riparian areas, resting or nesting areas for large numbers of waterfowl, rookeries, communal roost sites, strutting or breeding grounds for gallinaceous birds, calving grounds, and areas containing rare plant communities. Some States have programs to formally designate priority or rare habitat community types.

4.3.6.1 Regulations

Federal statutes that are directly applicable in a NEPA evaluation of terrestrial ecology issues include the ESA of 1973, the Migratory Bird Treaty Act of 1918 (MBTA) (16 USC 703-712), and portions of other statutes, such as the wetlands provisions of the CWA (see Section 4.3.5.1, "Regulations").

The MBTA was initially enacted in 1918 to implement the 1916 Convention between the United States and Great Britain (for Canada) for the protection of migratory birds. Specifically, the Act established a Federal prohibition, unless otherwise regulated, to pursue, hunt, take, capture, or kill any bird included in the terms of the convention, or any part, nest, or egg of any such bird. The MBTA was amended in 1936 to include species included in a similar convention between the United States and Mexico, in 1974 to include species included in a convention between the United States and Japan, and in 1978 in a treaty between the United States and the Soviet Union. Executive Order 13186 (2001) further defined the responsibilities of Federal agencies, such as the NRC, to ensure the protection of migratory birds and to consider potential impacts to migratory birds during the preparation of NEPA documents.

4.3.6.2 Potential Impacts of Decommissioning Activities on Terrestrial Ecological Resources

Table E-3 in Appendix E identifies stabilization, large-component removal, structure dismantlement, and decontamination and dismantlement as activities that may affect terrestrial ecology. Terrestrial ecological resources may be impacted during the decommissioning process via direct or indirect disturbance of native plant or animal communities in the vicinity of the plant site. Direct impacts can result from activities such as the clearing of native vegetation or filling of a wetland. Indirect impacts may result from effects such as erosional runoff, dust, or noise. During decommissioning, land at the site may be disturbed for the construction of laydown yards, stockpiles, and support facilities. Additionally, land away from the plant site may be disturbed to upgrade or install new transportation or utility systems. For example, building a new rail line may be necessary to support large-component removal. Installing or altering existing transmission lines could also have an effect on the terrestrial environment. In most cases, land disturbances will result in relatively short-term impacts and the land will either recover naturally or will be landscaped appropriately for an alternative use after completion of decommissioning.

Minor impacts to terrestrial resources could result from dust generation due to ground disturbance and traffic, noise from dismantlement of facilities and heavy equipment traffic, surface erosion and runoff, and migratory bird collisions with crane booms or other construction equipment. Most of these minor, indirect impacts are temporary and will not be significant issues after the completion of decommissioning. The effects of such impacts can also be minimized using standard BMPs.

Impacts to terrestrial resources are considered to be detectable if they result in changes to local species populations or plant or animal communities beyond the typical levels of natural variability (i.e., normal year-to-year variations). The impacts are considered to be destabilizing if they result in the extirpation of important species or result in long-term changes in ecological functions (such as flow of energy), species richness, diversity, or proportion of invasive species.

4.3.6.3 Evaluation

At most commercial nuclear facilities, there is a relatively distinct operational area where most or all site activities occur (e.g., materials and equipment storage, parking, substation operation, facility service and maintenance, etc.). This operational area usually includes all areas within the protected area fence, the intake, discharge, cooling, and other associated structures, as well as adjacent paved, graveled, and maintained landscaped areas. The operational area may include the entire area disturbed during facility construction, but is often considerably smaller.

Terrestrial habitats disturbed during the construction of the site will often continue to be of low habitat quality during plant operation and decommissioning. However, sensitive habitats can develop on the site or rare species can colonize the area disturbed during construction. This is especially true if the site has been in SAFSTOR for several decades. For example, reworking the ground surface during construction may have altered the surface-drainage patterns such that wetlands develop on the original construction site. Trees could grow to the point where they become usable as roosting or nesting sites for eagles, osprey, or wading birds. These habitats may be inhabited by sensitive species at the time of decommissioning. Rare species have colonized portions of the site at several operating commercial nuclear power plants.

In most cases, the amount of land required to support the decommissioning process is relatively small and is a small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the operational areas of the site and typically are within the protected area. Usually, there is sufficient room within the operational areas to function as temporary storage, laydown, and staging sites. In most cases, management, engineering, and administrative staff would have been assigned space in existing support or administration buildings. In some cases, the licensees have installed trailers or temporary buildings to house engineering and administrative staff or to otherwise support decommissioning. Most licensees expect to restrict decommissioning activities to highly disturbed operational areas but a few expect to use lands beyond the operational areas, as defined above. The licensees typically anticipate utilizing an area of between 0.4 ha (1 ac) to approximately 10.5 ha (26 ac) to support the decommissioning process. One facility (Big Rock Point) required a new transmission line ROW to provide electrical power to the plant site during decommissioning (this line will also provide power to the onsite independent spent fuel storage installation [ISFSI] after decommissioning is completed). However, construction of a new transmission line ROW is probably an unusual situation. It is expected that some sites will require the reconstruction or installation of new transportation links, such as railroad spurs, road upgrades, or barge slips. Activities conducted within the operational areas are not expected to have a detectable impact on important terrestrial resources. Activities conducted outside the operational areas may have detectable impacts, depending on the magnitude and type of activity and the resources potentially affected.

None of the decommissioning options have a greater likelihood of resulting in detectable or destabilizing impacts to terrestrial resources. The selection of the decommissioning option is more likely to affect the timing of the impact on ecological resources than it is the magnitude of the impacts. DECON may require slightly more land area to support a larger number of simultaneous activities. The ENTOMB2 option would probably have the least likelihood of adverse impacts onsite because some large components may be left in place, reducing the land requirements needed for large construction equipment, waste storage, and barge or rail loading

areas. However, impacts of ENTOMB2 could be larger if additional land disturbance is required to install a concrete batch plant and associated material stockpiles. The potential impacts of SAFSTOR may be smaller than DECON, depending on the time over which activities are performed. If decontamination and dismantlement occur slowly over many years (incremental DECON), the same storage and staging areas can be reused for sequential activities. If many activities are performed over a short time period at the end of the SAFSTOR period, the impacts may be as large as those for DECON. The activity of demolition of construction material should not have significant nonradiological impacts beyond other decommissioning activities except for potential short-term noise and dust effects.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on terrestrial ecology that are different from those found at other nuclear facilities.

4.3.6.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning activities on terrestrial resources, including comments received on the draft of Supplement 1 of NUREG-0586. For facilities where habitat disturbance is limited to operational areas, the impacts on terrestrial ecology are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for such facilities the potential impacts to terrestrial ecology are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If habitat disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions and cannot be predicted generically. Therefore, the staff concludes that if disturbance beyond the operational areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE and must be determined through site-specific analysis.

4.3.7 Threatened and Endangered Species

Plants and animals protected under the ESA of 1973 may be present at or near all commercial nuclear power facilities (Sackschewsky 1997). At operating plants, the most common potential impacts to endangered aquatic species are effects related to the operation of the cooling water system via impingement, entrainment, or occasional temperature or chemical effects. Because the cooling system is not used at a plant undergoing decommissioning, it is anticipated that the potential impacts of decommissioning on threatened or endangered aquatic species will normally be no greater than and likely far less than the potential impacts of plant operations.

For terrestrial species that are threatened or endangered, the most common potential impacts for operating plants are from transmission ROW maintenance activities. Most transmission lines beyond the switchyard are expected to remain energized, even after a commercial nuclear power facility closes operation, and the ROW maintenance activities are expected to continue. Therefore, the potential impacts of decommissioning on terrestrial species will normally be no greater than the potential impacts of plant operations.

4.3.7.1 Regulations

The ESA is the Federal statute that is directly applicable in a NEPA evaluation of threatened and endangered species issues. The ESA is intended to protect plant and animal species that are threatened with extinction and to provide a means to conserve the ecosystems on which they rely. Under the ESA, the U.S. Fish and Wildlife Service (USFWS) is responsible for all terrestrial and freshwater organisms. Marine and anadromous fish species are the responsibility of the National Marine Fisheries Service (NMFS). The ESA prohibits the taking of listed species and the destruction of designated critical habitat for listed species. The term "take" means to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect or attempt to engage in such conduct (16 USC 1532). The ESA applies to Federal agencies as well as individuals. However, in general, the prohibitions against take in respect to listed plant species are only applicable to Federal agencies or to individuals on Federal lands.

Section 7 of the ESA provides a means for Federal agencies to consult with USFWS and NMFS concerning impacts to endangered species resulting from Federal actions. Although USFWS and NMFS are the administering agencies, it is the responsibility of the action agency to determine the potential impacts of a proposed action (including licensing actions) on endangered or threatened species via the preparation of a biological assessment. If the consultation process results in a determination that there may be adverse impacts to listed species, Section 10 of the ESA provides a means for permitted takes that are incidental to otherwise legal activities.

4.3.7.2 Potential Impacts of Decommissioning Activities on Threatened and Endangered Species

Table E-3 in Appendix E indicates that stabilization, large-component removal, structural dismantlement, and decontamination and dismantlement are activities that may affect threatened or endangered species. Such species may be impacted during the decommissioning process either through direct take (kill, maim, or unable to reproduce) or via disturbances of native plant or animal communities near the plant site that the species relies on for food or

shelter. Additionally, an extended period of SAFSTOR may allow the establishment of onsite populations of protected species that may be adversely affected by facility decontamination and dismantlement at the end of the storage period.

The greatest potential for impact to protected species is associated with physical alteration or dismantlement of the facilities, landscape, or aquatic environment. Impacts can result from activities such as the removal of near-shore or in-water structures (e.g., the intake or discharge facilities); the active dredging of a stream, river, or ocean bottom; the filling of a stream, bay, or wetland; or the clearing of native vegetation. Indirect impacts may result from runoff, sedimentation, dust generation, or noise disturbance. The aquatic environment at a plant site may be disturbed for the construction of support facilities to allow barges to dock or to bridge a stream or other aquatic area. Additionally, terrestrial and aquatic environments away from the plant site may be disturbed to upgrade or install new transportation or utility systems. For example, a new rail line may be necessary to support large component removal. Installing or altering transmission lines could also affect the terrestrial and aquatic environment. In most cases, disturbances will result in relatively short-term impacts and the environment and local populations will either recover naturally or impacts can be mitigated using standard BMPs. An important exception may occur if near-shore or in-water structure removal or land surface disturbances result in the establishment of nonindigenous or noxious plants and animals to the exclusion of threatened or endangered species.

Impacts to endangered or threatened species are considered detectable if there are changes (attributable to the facility) in the species behavior or in the local population size that are greater than normal year-to-year variation. Impacts would be considered destabilizing if they result in direct mortality or major behavior changes (such as abandonment of most suitable habitat areas in the plant vicinity) or if they otherwise jeopardize the local population.

4.3.7.3 Evaluation

Usually, very little land will be disturbed during decommissioning that was not used during regular plant operations or previously disturbed during construction of the facility. If all activities are confined to site operational areas (i.e., within protected area fences, intake, discharge, cooling, and other associated structures, and adjacent paved, graveled, and maintained landscaped areas), the impacts to terrestrial threatened or endangered species are expected to be minor and nondetectable. Any impacts that did occur would primarily result from increased noise and dust generation from physical alterations of the plant site and from increased truck

traffic to and from the site. If no disturbances occur beyond the operational areas of the site, it is expected that the impact to threatened or endangered terrestrial species will be relatively small, temporary, and mitigable. The impacts of activities beyond the operational areas would depend on the activity, the species potentially affected, and the mitigation options available.

Unless there are major structural changes in the aquatic environment, the potential for adverse impacts to aquatic threatened or endangered species is expected to be minimal and nondetectable. Impacts to aquatic threatened or endangered species resulting from runoff/ sedimentation or chemical inputs during decommissioning will be significantly less than the potential entrainment and impingement impacts that were present when the plant was operating because of the drastically reduced water use.

The different decommissioning options will probably not differ significantly in potential impacts to threatened or endangered species, except in those cases where the plant is held in SAFSTOR for extended periods. In those cases, there is a greater potential for rare species to colonize areas that may subsequently be disturbed during the decommissioning process.

The likelihood of impacts to threatened and endangered species is related to their presence or absence. This issue requires consultation with appropriate agencies to determine whether threatened or endangered species are present and whether they would be adversely affected. Consultation under Section 7 of the ESA must be initiated to determine if protected species are near the plant. If species are identified, an assessment of the potential impacts of decommissioning must be determined. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on threatened and endangered species that are different from those found at other nuclear facilities.

4.3.7.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on threatened and endangered species, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has considered that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis.

The ESA imposes two basic requirements on the NRC. First, the ESA requires the NRC to ensure that any action authorized, funded, or carried out by NRC is not likely to jeopardize the continued existence of any endangered or threatened species, or to result in the destruction or impairment of any critical habitat for such species. Second, the NRC is required to consult with the Secretary of the Interior (for freshwater and terrestrial species through the USFWS) or the Secretary of Commerce (for marine and some anadromous fish through the NMFS) to

determine if any listed species may be affected by an action. This consultation may be formal or informal, depending on the nature of the action, the species potentially affected, and the level of impacts to those species.

Acknowledging the site- and species-specific nature of threatened and endangered species and the special obligations imposed on the NRC by the ESA, the staff has concluded that the potential impacts to threatened and endangered species may be SMALL, MODERATE, or LARGE, and is not a generic issue. Informal consultation will be initiated by the NRC staff with the appropriate service after the licensee announces permanent cessation of operations. It is expected that any formal or informal consultation will be completed prior to the licensee beginning major decommissioning activities, which can occur 90 days after the submission of the post-shutdown decommissioning activities report (PSDAR). At that time, it will be determined whether such species could be affected by decommissioning activities and whether formal consultation will be required to address the impacts. Each State should also be consulted about its own procedure for considering impacts to State-listed species.

4.3.8 Radiological

The NRC considers radiological doses to workers and members of the public when evaluating the potential consequences of decommissioning activities. Radioactive materials are present in the reactor and support facilities after operations cease and the fuel has been removed from the reactor core. Exposure to these radioactive materials during decommissioning may have consequences for workers. Members of the public may also potentially be exposed to radioactive materials that are released to the environment during the decommissioning process. All decommissioning activities were assessed to determine their potential for radiation exposures that may result in health effects to workers and the public. This section considers the impacts to workers and the public during decommissioning activities performed up to the time of the termination of the license. Any potential radiological impacts following license termination are not considered in this Supplement. Such impacts are covered by the *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities*, NUREG-1496 (NRC 1997).

4.3.8.1 Regulations

Decommissioning reactors in the United States continue to be licensed by the NRC and must comply with NRC regulations and conditions specified in the license. The regulatory standards for radiation exposure to workers and members of the public are found in 10 CFR Part 20 (see detailed discussion in Appendix G). Title 10 CFR Part 20 requires that the sum of the external and internal doses (total effective dose equivalent, or TEDE) for a member of the public may

not exceed 1 mSv/yr (0.1 rem/yr). Compliance is demonstrated by measurement or calculation, to show (1) that the highest dose to an individual member of the public from sources under the licensee's control does not exceed the limit or (2) that the annual average concentrations of radioactive material released in gaseous and liquid effluents do not exceed the levels specified in 10 CFR Part 20, Appendix B, Table 2, at the unrestricted area boundary. In addition, the dose from external sources in an unrestricted area should not exceed 0.02 mSv (0.002 rem) in any given hour or 0.5 mSv (0.05 rem) in 1 yr. Occupational doses are limited to a maximum of 0.05 Sv (5 rem) TEDE per year, with separate limits for dose to various tissues and organs.

Potential radiological impacts following license termination are not covered in this Supplement. Specific radiological criteria for license termination were added as Subpart E of 10 CFR Part 20 in 1997, and the basis for public health and safety considerations is discussed in NUREG-1496 (NRC 1997). These criteria limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) from all pathways following unrestricted release of a property. In cases where unrestricted release is not feasible, the licensee must provide for institutional controls that would limit the dose to members of the public to 0.25 mSv/yr (25 mrem/yr) during the control period and to 1 mSv/yr (100 mrem/yr) after the end of institutional controls. These criteria will largely determine the types and extent of activities undertaken during the decommissioning process to reduce the radionuclide inventory remaining onsite.

Power reactor licensees are required to meet the requirements in 10 CFR 50.36a for effluent releases after permanent cessation of operations. Licensees are also required to keep releases of radioactive materials to unrestricted areas at levels as low as reasonably achievable (ALARA).

In addition to NRC limits on effluent releases, nuclear power facility releases to the environment must comply with EPA standards in 40 CFR Part 190, "Environmental radiation protection standards for nuclear power operations." These standards specify limits on the annual dose equivalent from normal operations of uranium fuel-cycle facilities (except mining, waste disposal operations, transportation, and reuse of recovered special nuclear and by-product materials). Radon and its decay products are excluded from these standards.

The NRC has not established standards for radiological exposures to biota other than humans on the basis that limits established for the maximally exposed members of the public would provide adequate protection for other species. In contrast to the regulatory approach applied to human exposures, the fate of individual nonhuman organisms is of less concern than the maintenance of the endemic population (NCRP 1991). Because of the relatively lower

sensitivity of nonhuman species to radiation, and the lack of evidence that nonhuman populations or ecosystems would experience detrimental effects at radiation levels found in the environment around nuclear power facilities, these effects are not evaluated in detail for the purposes of this Supplement.

4.3.8.2 Potential Radiological Impacts of Decommissioning Activities

As indicated in Table E-3 in Appendix E, all decommissioning activities have potential radiological concerns. Radiological impacts during decommissioning include offsite dose to members of the public and occupational dose to the work force at the facility. For this Supplement, public and occupational radiation exposures from decommissioning activities have been evaluated on the basis of information derived from recent decommissioning experience. Effluent releases anticipated during decommissioning were estimated from experiences in recent decommissioning activities from both PWRs and boiling water reactors (BWRs).

Many activities that take place during decommissioning are generally similar to those that occur during normal operations and maintenance activities. Those activities include decontamination of piping and surfaces in order to reduce the dose to nearby workers. Removal of piping or other components, such as pumps and valves, and even large components, such as heat exchangers, is performed in operating facilities during maintenance outages. However, some of the activities, such as removal of the reactor vessel or demolition of facilities, would be unique to the decommissioning process. Those activities would have the potential to result in exposures to workers who are close to contaminated structures or components, and to provide pathways for release of radioactive materials to the environment that are not present during normal operation.

4.3.8.3 Evaluation

At the cessation of plant operations, there are areas of the plant structures where residual radiation exceeds the radiation standards for license termination set forth in 10 CFR Part 20, Subpart E. One of the goals of decommissioning is to reduce this residual radiation to levels that would permit license termination. Most of the decommissioning activities listed in Table E-3 in Appendix E have the potential for radiological impacts. The staff expects that all of the activities that have potential radiological impacts will be conducted following approved procedures to keep doses ALARA and well within regulatory limits. Radiological impacts are considered to be undetectable and nondestabilizing, in the NEPA sense, if doses remain within regulatory limits.

For this Supplement, information gained from experience in decommissioning facilities has been used to evaluate radiological dose to workers and members of the public. Occupational

doses, radionuclide emissions, and doses to members of the public during decommissioning were compared to those experienced during periods of routine operation at the same facilities or at similar facilities. They were also compared to estimates presented in the 1988 GEIS (NUREG-0586 [NRC 1988]). This comparison was intended to demonstrate that the radiological consequences actually experienced at facilities undergoing decommissioning were bounded either by the site's EIS for normal operations or by the 1988 GEIS. The data were also used to determine whether it was appropriate to update the estimates for these impacts as presented in the 1988 GEIS.

In estimating the health effects resulting from both offsite and occupational radiation exposures as a result of decommissioning of nuclear power facilities, the staff used the risk coefficients per unit dose recommended by the International Commission on Radiological Protection (ICRP) (1991) for stochastic health effects such as development of cancer or genetic effects. The coefficients consider the most recent radiobiological and epidemiological information available and are consistent with those used by the United Nations Scientific Committee on the Effects of Atomic Radiation. The coefficients used in this Supplement are the same as those published by ICRP (1991) in connection with a revision of its recommendations for public and occupational dose limits. Excess hereditary effects are listed separately because radiation-induced effects of this type have not been observed in any human population, as opposed to excess malignancies that have been identified among populations receiving instantaneous and near-uniform exposures in excess of 0.1 Sv (10 rem). Regulatory limits for radiation exposure to specific organs and tissues are set at levels that would prevent development of nonstochastic effects. Therefore, nonstochastic effects, such as development of radiation-induced cataracts, would not be expected in any individual whose exposure remains within the regulatory limits.

Occupational Dose: As part of the occupational dose analysis, data were collected for annual occupational doses, doses by activity, and total dose from decommissioning, when that information was available. Because many of the facilities that provided information have not completed the decommissioning process, the data included in this analysis is from both actual operating data and from projections for specific activities. Routine occupational doses as reported to the NRC were used to compare collective worker doses during normal operations to those experienced during decommissioning. Projections for specific activities were also used to determine which were the greatest contributors to the cumulative occupational doses over the entire decommissioning period.

The data used for this evaluation are presented in Appendix G. Average occupational doses during the 5 years of normal operations preceding shutdown ranged from about 1.5 to 5 person-Sv (150 to 500 person-rem) per year for each reactor. The average annual collective doses during the years following shutdown were generally lower, ranging from less than 0.1 to

1.8 person-Sv (10 to 180 person-rem), although specific years during the most active decommissioning period may have produced collective worker doses comparable to, or greater than, those typically experienced during normal operation. Average annual doses to individual workers are also generally lower during decommissioning than during normal operation.

Table 4-1 compares cumulative occupational dose estimates from the 1988 GEIS (NRC 1988) to estimates for plants that are currently in the decommissioning process. The types of activities included in these estimates may vary between plants. For example, some estimates include doses from transportation or from activities related to spent fuel management, which are not considered part of the decommissioning process, as defined in the scope of this document. In general, estimates for currently decommissioning plants fell within the range of estimates in the 1988 GEIS, and in some cases were substantially lower than the Supplement 1 estimates for the corresponding type of reactor and decommissioning option.

The estimated cumulative doses for the entire decommissioning process ranged from about 3.5 to 16 person-Sv (350 to 1600 person-rem) for the facilities that provided data. Estimated doses for the reference facilities discussed in the 1988 GEIS ranged from 3 to 19 person-Sv (300 to 1900 person-rem). Because the range of cumulative occupational doses reported by reactors undergoing decommissioning was similar to the range of estimates for reference plants presented in the 1988 GEIS, it was not considered necessary to update the estimates in the previous document at this time.

Activities that resulted in the largest doses during decommissioning included removal of large components, such as the reactor vessel and steam generators. Dismantling the internal structures within the containment building was the activity producing the largest overall doses. Transportation and management of spent fuel each accounted for less than 10 percent of the total. Appendix G provides a more in-depth review of the exposures recorded and anticipated for various activities.

One of the major decommissioning activities that is not performed during routine operation or refurbishment is removal of the reactor vessel. Industry experiences from this activity were reviewed to estimate worker exposure and the amount of radioactive material removed (see Appendix H). As each utility performed this major activity, experiences were shared within the industry and the lessons learned have been used to reduce collective dose to workers and improve the process. Collective worker dose at these sites ranged from 0.14 to 1.8 person-Sv (14 to 180 person-rem). The dismantlement of radioactive structures for the ENTOMB2 option would involve placement of contaminated SSCs in the reactor or containment building.

Facilities could use a demolition process for dismantlement of uncontaminated or slightly contaminated structures; there is a potential for this activity to occur during the dismantlement phases of SAFSTOR, DECON, or ENTOMB1 options. The demolition debris could be disposed of onsite if nonradiologically contaminated. If the debris is radiologically contaminated, it could be sent to a LLW site (except for the ENTOMB1 option, where it would be disposed of in the reactor or containment building structure). However, in cases where the remaining activity was low enough that the licensee could meet the criteria in 10 CFR Part 20, Subpart E, and other regulations, the demolition debris could potentially be disposed onsite for either the DECON or SAFSTOR options. This process has been termed "Rubblization" (see Section 1.3). Rubblization would require a site-specific analysis. The site-specific analysis would be conducted at the time the LTP is submitted for the site. Occupational doses during the activity of crushing the material would be similar to those for dismantlement of the facility in preparation for demolition and offsite disposal. The occupational doses would need to meet the regulatory standards in 10 CFR Part 20. Disposal of the radiologically contaminated demolition debris onsite would also have to meet the radiological criteria for license termination given in 10 CFR Part 20, Subpart E.

Occupational doses to individual workers during decommissioning activities are estimated to average approximately 5 percent of the regulatory dose limits in 10 CFR Part 20, and to be similar to, or lower than, the doses experienced by workers in operating facilities. The average increase in fatal individual cancer risk to a worker during decommissioning, about 8×10^{-5} per year of employment, is less than 2 percent of the lifetime accumulation of occupational risk of premature death of 4.8×10^{-3}. Because the ALARA program continues to reduce occupational doses, no additional mitigation program is warranted.

Public Dose: This section addresses the impacts on members of the public from radiation doses caused by decommissioning activities, including doses from effluents as well as from direct radiation. To determine the relative significance of the estimated public dose for decommissioning, the staff compared dose projections for decommissioning with the historical (baseline) doses experienced at PWRs and BWRs during normal operations. The dose estimates were based on reports evaluating effluent releases during decommissioning efforts and are shown in Appendix G. Levels of radionuclide emissions from facilities undergoing decommissioning decreased because the major sources generating emissions in gaseous and liquid effluents are absent in facilities that have been shut down. However, decommissioning facilities continued to report low levels of radionuclide emissions that resulted from the residual radioactive materials remaining in the facilities. The doses to members of the public from these emissions were also very low. Collective doses to members of the public within 80 km (50 mi) were lower than 0.01 person-Sv (1 person-rem) per year at all decommissioning facilities for

Table 4-1. Comparison of Occupational Dose Estimates from NUREG-0586 (NRC 1988) to those for Decommissioning Reactors

Reactor Type/ Decommissioning Option	1988 GEIS Estimates - Cumulative Occupational Dose, person-Sv (person-rem)	Range of Estimates for Decommissioning Plants - Cumulative Occupational Dose, person-Sv (person-rem)[a]
Boiling Water Reactors		
DECON	18.74 (1874)	7 - 16 (700 - 1600)
SAFSTOR	3.26 - 8.34 (326 - 834)	3.5 (350)
ENTOMB	15.43 - 16.72 (1543 - 1672)	–
Pressurized Water Reactors		
DECON	12.15 (1215)	5.6 - 10 (560 - 1000)
SAFSTOR	3.08 - 6.694 (308 - 664)	4.8 - 11 (480 - 1100)[b]
ENTOMB	9.16 - 10.21 (916 - 1021)	–
Other Reactors (HTGR; FBR)	–[c]	4.3 (430)

(a) These data are based on information provided by plants that are undergoing or have completed the decommissioning process. For facilities that have been completely decommissioned, they represent actual doses accumulated during the decommissioning period For facilities that are still undergoing decommissioning, they represent a combination of actual doses accumulated during activities that have been completed and projected doses for future activities.

(b) The plant reporting a dose estimate of 1100 person-rem is designated as having elected the SAFSTOR option; however, the period between shutdown and active decommissioning was shorter than the minimum 10-year SAFSTOR period that was evaluated in the 1988 GEIS. Therefore, it may be more appropriate to compare the estimated dose for that facility to the 1988 GEIS estimates for the DECON option.

(c) The 1988 GEIS did not provide dose estimates for reactors other than reference light water reactors. Therefore, there are no previous estimates with which to compare the doses for decommissioning the HTGRs and FBR, which are somewhat unique in the commercial nuclear power industry. The dose estimates are expected to be consistent with PWRs and BWRs

which data were available, and, in most cases, they were comparable to or lower than the doses from operating facilities. Doses to a maximally exposed individual were less than 0.01 mSv/yr (1 mrem/yr) at both operating and decommissioning facilities, which is well within the regulatory standards in 10 CFR Part 20 and Part 50.

Offsite doses to the public attributable to decommissioning have been examined for both the maximally exposed individual and the collective doses to the population within 80 km (50 mi) of the plants. To date, effluents and doses during periods of major decommissioning have not differed substantially from those experienced during normal operation. Consequently, direct

exposure and effluents in gaseous and liquid discharges are not expected to result in maximum individual doses exceeding the design objectives of Appendix I to 10 CFR Part 50, the dose and effluent concentration limits in 10 CFR Part 20, or the limits established by EPA in 40 CFR Part 190. Both the average individual dose and the 80-km (50-mi) radius collective doses are expected to remain at least 1000 times lower than the dose from natural background radiation. It should also be noted that the estimated increased risk of fatal cancer to an average member of the public is much less than 1×10^{-6}. Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in occupational or public doses that are different from those found at other nuclear facilities.

4.3.8.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential radiological impacts of decommissioning. This information indicates that the radiological impacts of decommissioning will remain within regulatory limits. Therefore, the staff makes the generic conclusion that the radiological impacts of decommissioning activities are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

The staff also determined that the issue of the long-term radiological aspects of Rubblization or onsite disposal of slightly contaminated material could not be evaluated generically and would require a site-specific analysis. The site-specific analysis would be conducted at the time the LTP for the site is submitted.

4.3.9 Radiological Accidents

As indicated in the Introduction to this Supplement, the staff relies on the Waste Confidence Rule for determining the acceptability of environmental impacts from the storage and maintenance of fuel in the spent fuel pool. The Rule states, in part, that there is, "reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant impact for at least 30 yrs beyond the licensed life for operation...of that reactor at its spent fuel storage basin" (54 FR 39767).[a] However, for the purpose of public information, the staff has elected to include a discussion of potential accidents related to the spent fuel pool in this Supplement.

(a) The Commission reaffirmed this finding of insignificant environmental impacts in 1999 (64 FR 68005). This finding is codified in the Commission's regulations in 10 CFR 51.23(a).

The likelihood of a large offsite radiological release that impacts public health and safety from a facility that has permanently ceased operation is considerably lower than the likelihood of a release from an operating reactor that impacts public health and safety. This is because the potential accidents associated with reactor operation are no longer relevant after the reactor fuel has been removed.

Radiological accidents considered in licensing nuclear power plants are classified as design basis accidents (DBAs) and severe (beyond design basis) accidents. DBAs are those accidents that both the licensee and the NRC staff evaluate to ensure that the plant can withstand normal and abnormal transients and a broad spectrum of postulated accidents without undue hazard to the health and safety of the public. Severe accidents are those that are beyond the design basis of the plant. They are more severe than DBAs because they may result in substantial damage to the fuel, whether or not there are serious offsite consequences. For the most part, DBAs focus on reactor operation and are not applicable to plants undergoing decommissioning. The only DBAs or severe accidents (beyond design basis) applicable to a decommissioning plant are those involving the spent fuel pool. These postulated accidents are not expected to occur during the life of the plant, but are evaluated to establish the design basis for the preventive and mitigative safety systems of the spent fuel storage facility.

4.3.9.1 Regulations

Regulations governing accidents that must be addressed by nuclear power facilities, both operating and shutdown, are found in 10 CFR Part 50 and 10 CFR Part 100. The environmental impacts of DBAs, including those associated with the spent fuel pool, are evaluated during the initial licensing process. The ability of the plant to withstand these accidents is demonstrated to be acceptable before issuance of the operating license. The results of these evaluations are found in license documentation, such as the staff's safety evaluation report, the final environmental statement (FES), and in the licensee's Final Safety Analysis Report (FSAR) or equivalent. The consequences for these events are evaluated for the hypothetical maximally exposed individual. The licensee is required to maintain the acceptable design and performance criteria throughout the life of the plant.

In addition, Appendix E to 10 CFR Part 50 requires each licensee to develop emergency plans and implementing procedures to protect health and safety in the event of an accident. These plans and procedures are maintained up to date during the period of operation of the plant and until such time afer the cessation of plant operations that the NRC grants relief from the emergency planning requirements.

4.3.9.2 Potential for Radiological Accidents as a Result of Decommissioning Activities

Table E-3 in Appendix E indicates that fuel removal, organizational changes, stabilization, chemical decontamination, large component removal, decontamination and dismantlement, system dismantlement, entombment, and transportation are activities that may lead to radiological accidents. Many activities that occur during decommissioning are similar to activities, such as decontamination and equipment removal that commonly take place during maintenance outages at operating plants. However, during decommissioning such activities may be more extensive than similar activities during the period of reactor operations. Consequently, potential accidents associated with these activities may have a higher probability during decommissioning than when the plant is operating. Accidents that occur during these activities may result in injury and local contamination; they are not likely to result in contamination offsite. This section addresses worker injuries from radiological accidents. Injuries from other causes are addressed in Section 4.3.10,"Occupational Issues."

Once the reactor fuel has been moved to the spent fuel pool, the only DBAs contained in the plant's FSAR that are applicable are those associated with the spent fuel pool. These accidents are generally related to fuel handling or dropping heavy objects into the spent fuel pool. As long as the integrity of the spent fuel pool and its supporting systems is maintained, the potential impacts of accidents are bounded by the impacts of those for the spent fuel pool DBAs.

After permanent shutdown of the reactor, the only severe accident of concern is one where the fuel in the spent fuel pool becomes uncovered and results in a zircaloy fire. In this regard, the staff recently conducted a study of spent fuel pool accident risk at decommissioning nuclear power facilities to support development of a risk-informed technical basis for reviewing exemption requests and a regulatory framework for integrated rulemaking (NRC 2001b). As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff determined the frequency of beyond-design-basis spent fuel pool accidents. The event initiators included:

- seismic events (earthquakes)aircraft crashes
- aircraft crashes
- tornadoes and high winds

- impact of a dropped heavy load (such as a fuel cask), resulting in pool drainage or compression or buckling of stored assemblies.

Those spent fuel pool accident sequences that resulted in the spent fuel being uncovered were assumed to culminate in a zirconium fire. The consequences of a zirconium fire event are likely to be severe. The staff's study performed some bounding-consequences analyses.

The impacts of accidents where onsite and offsite doses remain below those allowable for the workers or the public are considered to be undetectable. Accidents that are likely to be undetectable include temporary loss of services, certain decontamination-related accidents, such as liquid spills or leaks during in situ decontamination, and, in some cases, the temporary loss of offsite power or compressed air. The impacts of accidents that could result in offsite doses that exceed EPA's protective action guides (PAGs) (EPA 1991) are considered to be destabilizing. The only accidents that are likely to have destabilizing impacts are those that involve pool drainage that leads to a zirconium fire.

4.3.9.3 Evaluation

The information in this section is based on reviews of existing information from licensees' documents analyzing accidents from decommissioning activities and from a technical review of spent fuel pool accident risk at decommissioning nuclear power facilities. The review of spent fuel pool accidents at decommissioning reactors was performed to support development of a risk-informed technical basis for reviewing emergency plan exemption requests and a regulatory framework for integrated rulemaking (NRC 2001b). Further detail on the sources of information that were used to develop the analysis is given in Appendix I. Because the sources of information included the FBR and the HTGR, the results given in this section are applicable for these facilities.

The accidents and malfunctions covered by licensing documents can be divided into five main categories:

- Fuel-related accidents: These include maintenance and storage of fuel in the spent fuel pool and the movement of fuel into the pool, which could result in fuel rod drops, heavy load drops, and loss of water.

- Other radiological- (nonfuel)-related accidents: These include onsite accidents related to decontamination or dismantlement activities (e.g., material-handling accidents or accidental cutting of contaminated piping) or storage activities (e.g., fires or ruptures of liquid waste tanks).

- External events: These include aircraft crashes, floods, tornadoes and extreme winds, earthquakes, volcanic activity, forest fires, lightening storms, freezing, and sabotage.

- Offsite events: These consist solely of transportation accidents that occur offsite (transportation accidents are discussed in Section 4.3.17).

- Hazardous (nonradiological) chemical-related accidents: These have the potential for injury to the offsite public, either directly from the accident or as a result of further actions initiated by the accident.

A detailed list of the types of accidents that could occur in each of these five categories is given in Appendix I. Appendix I also contains a table showing the estimated dose consequences of accidents during the decommissioning period that were reported in various licensing-basis documents. The highest doses result from postulated fuel-related accidents and radioactive-material-related accidents. Information obtained from licensing-basis documents for the fuel-related accidents showed that the highest offsite doses were from the cask or heavy load-handling accidents, the accidents that assumed a 100 percent fuel failure, and the spent fuel-handling accidents. The postulated accident with the greatest estimated offsite dose was a spent resin-handling accident that had a calculated offsite dose consequence accident of 0.0096 Sv (0.96-rem) TEDE.

The likelihood of an accident as well as its consequence are activity-dependent. Accidents related to dropping fuel elements occur only when the fuel is being moved. Accidents related to dismantlement activities would occur only during the decontamination and dismantlement process and not during a storage period or after a facility has been entombed. External events, however, could occur during any activity or decommissioning option. Table I-5 in Appendix I compares the types of accidents with the different activities that are performed during SAFSTOR, ENTOMB, and DECON.

The staff has reviewed activities associated with decommissioning and determined that many decommissioning activities not involving spent fuel that are likely to result in radiological accidents are similar to activities conducted during the period of reactor operations. The radiological releases from potential accidents associated with these activities may be detectable. However, work procedures are designed to minimize both the likelihood of an accident and the consequences of an accident, should one occur, and emergency plans and procedures will remain in place to protect health and safety while the possibility of significant radiological accidents exists.

In addition to the licensing-basis documents reviewed, the staff's report, *Technical Study of Spent Fuel Pool Accident Risk at Decommissioning Nuclear Power Plants* (NRC 2001b), provides an analysis of the consequences of the spent fuel pool accident risk and includes a limited analysis of the offsite consequences of a severe spent fuel pool accident. These analyses showed that the consequences of a spent fuel accident could be comparable to those for a severe reactor accident. As part of its effort to develop generic, risk-informed requirements for decommissioning, the staff performed analysis of the offsite radiological consequences of beyond-design-basis spent fuel pool accidents using fission product inventories at 30 and 90 days and 2, 5, and 10 years. The results of the study indicate that the risk at spent fuel pools is low and well within the Commission's Quantitative Health Objectives. The risk is low because of the very low likelihood of a zirconium fire even though the consequences from a zirconium fire could be serious.

The Commission has considered the storage of spent fuel and has concluded in the Waste Confidence Rule in 10 CFR 51.23 that "... spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation...." The staff has reviewed the potential accidents associated with spent fuel storage during decommissioning, the likelihood of the accidents, and the potential consequences of the accidents. Emergency plans and procedures will remain in place to protect health and safety while the possibility of significant radiological accidents associated with spent fuel exists.

4.3.9.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, concerning the potential impacts of non-spent-fuel-related radiological accidents resulting from decommissioning. This information indicates, that with the mitigation procedures in place, the impacts of radiological accidents are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts of non-spent-fuel-related radiological accidents are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of spent-fuel-related radiological accidents resulting from decommissioning. The staff affirms the conclusions in the Waste Confidence Rule and concludes that the impacts of spent fuel storage are SMALL. The staff concludes that additional mitigation measures are not likely to be sufficiently beneficial to be warranted.

4.3.10 Occupational Issues

Occupational issues are related to human heath and safety. The discussion here includes physical, chemical, ergonomic, and biological hazards. This discussion does not include radiological impacts, which are discussed in Section 4.3.8.

4.3.10.1 Regulations

The Occupational Safety and Health Act of 1970 (29 USC 651 et seq.) was enacted to safeguard the health of the worker. Regulations implementing the act are found in Title 29 ("Labor") of the Code of Federal Regulations, Subtitle B, "Regulations Relating to Labor." Subpart A of 29 CFR Part 1910 adopts, by reference, occupational safety and health standards which have been found to be national consensus standards or established Federal standards. Standards adopted in 29 CFR 1910.6 include, among others, standards of the American National Standards Institute, the American Society for Testing and Materials, the American Welding Society, the National Fire Protection Association, the National Institute for Occupational Safety and Health, the Society of Automotive Engineers, and Underwriters Laboratories. Specific safety and health regulations for Construction are included in 29 CFR Part 1926. These regulations are administered by the Occupational Safety and Health Administration (OSHA).

States may also develop and enforce State standards for occupational safety and health. However, State agencies may not assert jurisdiction over any occupational safety or health issue with respect to which a Federal standard has been issued under Section 6 of the Occupational Safety and Health Act unless the State has a plan for the development and enforcement of State standards. State plans for development and enforcement of State standards are covered by 29 CFR Part 1902. Approved State plans for enforcement of State standards are listed in 29 CFR Part 1952. These plans identify the State agency responsible for development and enforcement of the State standards.

4.3.10.2 Potential Impacts of Decommissioning Activities on Occupational Issues

Table E-3 in Appendix E indicates that nearly all decommissioning activities may impact occupational issues. Typical hazards of concern can be grouped into the following categories: physical, chemical, ergonomic, biological, and radiological (Plog 1988). Radiological hazards are discussed in Section 4.3.8, and other hazards are discussed in this section in the context of decommissioning activities.

The impacts of decommissioning activities on occupational issues are considered detectable if the accident or injury rate during decommissioning exceeds average U.S. industrial accident rates. The impacts of decommissioning activities on occupational issues are considered destabilizing if the accident or injury rate during decommissioning becomes sufficiently large that decommissioning activities must be halted to address worker safety and the decommissioning schedule is threatened.

4.3.10.3 Evaluation

Typically, any significant operation, such as decommissioning, will have an environment, safety and health (ES&H) plan that serves as the guidebook for anticipating and preventing any injury or harm occurring to the worker while working on that particular job. This plan addresses all the major occupational hazards and is used to ensure that OSHA, State, and other local standards are met. The site-specific ES&H plan for a decommissioning activity should be referred to for detailed information regarding specific worker health and safety information; the occupational hazards described in this Supplement should not be used for ensuring the protection of an individual worker health and safety.

Physical hazards: During the decommissioning process, the major sources of physical occupational hazards involve the operation and use of construction and transportation equipment. Vehicles, grinders, saws, pneumatic drills, compressors, and torches are some of the more common equipment that can cause injury if improperly used. Heavy loads, which are often moved about by cranes and loaders, must be controlled to avoid injury. The majority of these hazards will be part of dismantlement. Workplace designs and controls should be the first line of defense when preventing workplace injuries. Hard hats and other personal protective equipment (PPE) are also important interventions and can serve as a secondary protective measure should workplace controls fail.

Many activities during decommissioning, for example, the use of cutting torches, have the potential to initiate fires. These activities, which are common during construction and demolition, should be identified in advance. It is expected that precautions will be taken to minimize the likelihood of fires and that suitable measures will be available for dealing with fires should they occur.

Table 4-2. Predicted Noise Ranges from Significant Construction Equipment (EPA 1971)

Equipment	Levels in dBA at 15 m (50 ft)
Trucks	82-95
Front loader	73-86
Cranes (derrick)	86-89
Pneumatic impact equipment	83-88
Jackhammers	81-98
Pumps	68-72
Generators	71-83
Compressors	75-87
Back hoe	73-95
Tractor	77-98
Scraper/grader	80-93

Noise is also a physical hazard that will be significant during decommissioning. The majority of noise will come from equipment such as rivet busters, grinders, and fans. Table 4-2 lists the typical A-weighted sound levels (decibel [dBA] levels) of standard construction equipment without the use of noise control devices or other noise-reducing design features. Although workplace controls and designs are the best methods for reducing noise, PPE (e.g., earplugs) can also be used to protect against hearing loss. If workers need to use PPE, their ability to communicate effectively is reduced and safety may be compromised.

Temperature is a physical hazard that will vary, depending on the decommissioning location and the amount of indoor versus outdoor activity. Heat and cold stress should be considered in any decommissioning plans. Normal core temperatures are 37.6°C (99.6°F) or 37°C (98.6°F) as measured by mouth. Fluctuations in core temperatures of 1.1°C (2°F) below or 1.7°C (3°F) above the normal impair performance markedly. If this range is exceeded, health hazards, e.g., hypothermia or heatstroke, exist (Plog 1988).

Physical hazards are prevalent at all the decommissioning sites. The loudest dBA noise hazard at one plant was the fan noise of 107 dBA (see Section 4.3.16, "Noise"). One facility undergoing decommissioning provided information on the number of safety occurrences (minor and injuries), accident prevention notices, PPE violations, near misses, and OSHA reportables. Many PPE violations appear to be repeat offenders. Most of the injuries and incidents noted occur in the construction area. The maximum yearly number of incidents and injuries (37) appeared in 1998 with a high number of PPE violations (53) also occurring during this reporting year. Typically, no lost work time is attributed to injuries or incidents.

Electrical hazards are a significant concern during decommissioning. During stabilization, licensees often rewire the site to eliminate unneeded electrical circuits or repower certain operations from outside. For SAFSTOR, monitoring equipment may need to be installed and some systems will need to be de-energized. All of these activities, plus various other activities (operating cranes near power lines, digging near buried cables, etc.), pose electrical threats to workers. Proper precautions should be taken to avoid injury.

Chemical hazards: Inhalation and dermal contact with chemicals are serious worker health hazards. Ingestion is typically not a voluntary route of exposure but accidental ingestions (pipetting with mouth, siphoning gasoline, etc.) have been known to occur at the job site. Solvents and particulates are the two contaminants of greatest concern. Some of the key chemicals of concern found in building materials, paints, light bulbs, light fixtures, switches, electrical components, and high-voltage cables include asbestos, lead, polychlorobiphenyls (PCBs), and mercury. Other chemicals that have been found during decommissioning activities include low levels of potassium, sodium chromate, and nickel found in the suppression chamber. Also, quartz and cristobalite silica were detected during concrete demolition. Fumes, often including lead and arsenic, and smoke from flame cutting and welding are significant sources of chemical exposure during decommissioning.

Decommissioning involves many activities that expose workers to chemical hazards:

- chemical decontamination of the primary loop
- removal of reactor components
- decontamination of the piping walls
- removal of contaminated soil
- removal of radioactive structures

- removal of hydrocarbon fuel from storage
- removal of hazardous coatings
- removal of asbestos
- removal of chemical-containing systems, such as demineralizers and acid- and caustic-containing tanks
- removal of sodium and NaK residue.

Proper planning, workplace design, and engineering controls should be supplemented with PPE and appropriate administrative solutions to ensure adequate worker protection from not only chemical hazards but all hazards.

Chemical hazards at one facility undergoing decommissioning included lead and arsenic vapors, created from torch cutting and using the plasma arc, and quartz and cristobalite particulates, created from chipping and hammering. At the facility, air sample summary logs indicate a few exposures that exceeded OSHA's permissible exposure limit (PEL). Arsenic (PEL = 0.01 mg/m^3) levels exceeded the PEL four times during the sampling period. The highest arsenic reading was 0.03 mg/m^3 when using the torch and grinder to cut a hole during one activity. The same activity reported the only lead (PEL = 0.05 mg/m^3) reading above PEL at 1.5 mg/m^3. Quartz (PEL = 0.1 mg/m^3) and cristobalite (PEL = 0.05 mg/m^3) particulates greatly exceeded the PELs when using the chipping hammer (817.84 and 1.5 mg/m^3, respectively). The drill and chipping hammer also created too much quartz dust (9.2 mg/m^3).

Ergonomic hazards: The physiological and psychological demands of decommissioning work create ergonomic hazards in the workplace. Discomfort and fatigue are two indicators of ergonomic stress that can lead to decreased performance, decreased safety, and increased chance of injury (Plog 1988). The typical sources of ergonomic stress during decommissioning activities include mechanical vibrations, lifting, and static work. Workplace designs, work shifts, and breaks should be planned accordingly to avoid ergonomic stress.

Biological hazards: Biological hazards include any virus, bacteria, fungus, parasite, or living organism that can cause a disease in human beings (Plog 1988). Typical sanitation practices can help avoid the obvious vectors for disease. Having clean, potable drinking water, marking nonpotable water, and providing cleansing areas are the most important elements of a sanitation system.

Given that many nuclear reactor facilities undergoing decommissioning are old, there is an increased chance that workers will be exposed to molds and other biological organisms that grow in and on the buildings. Molds and fungus, when inhaled, can cause minor to serious pulmonary problems. Dermal contact could cause rash and/or irritation. A thorough inspection of the facility should be conducted and proper cleansing and PPE should be used when biological agents are identified.

In general, human health risks for most decommissioning options are expected to be dominated by occupational injuries to workers engaged in activities such as construction, maintenance, and excavation. Historically, actual injury and fatality rates at nuclear reactor facilities have been lower than the average U.S. industrial rates. Occupational injury and fatality risks are reduced by strict adherence to NRC and OSHA safety standards, practices, and procedures. Appropriate State and local statutes must also be considered when assessing the occupational hazards and health risks for any decommissioning activity. The staff assumes strict adherence to NRC, OSHA, and State safety standards, practices, and procedures during decommissioning.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in occupational hazard issues that are different from those found at other nuclear reactor facilities.

4.3.10.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning activities on occupational issues. This information indicates that the impacts on occupational issues are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential impacts on occupational issues are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.11 Cost

A decommissioning cost assessment is not a NEPA requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

4.3.11.1 Regulations

The regulatory procedure for decommissioning a nuclear power facility is set out principally in NRC regulations in 10 CFR 50.75, 50.82, 51.53, and 51.95. The regulations to ensure the safe and timely decommissioning of nuclear power facilities and the availability of decommissioning funds were originally established by the NRC in 1988. These regulations, principally 10 CFR 50.75, specify the minimum amount of funds that a LWR licensee must have to demonstrate reasonable assurance of sufficient funds for decommissioning. The minimum decommissioning funds required by the NRC reflect only the efforts necessary to achieve termination of the 10 CFR Part 50 license. Costs associated with other activities related to facility deactivation and site closure, including operation of the spent fuel storage pool, construction, operation, and decommissioning of an ISFSI, demolition of uncontaminated or decontaminated structures that meet release criteria, and site restoration activities after sufficient residual radioactivity has been removed to meet NRC license termination requirements are not included in the minimum decommissioning fund requirement.

The regulations in 10 CFR 50.75 also require that licensees submit, at least once every 2 years, a report on the status of its decommissioning fund, including specifying the amount of funds accumulated, and a schedule for accumulating the remainder to be collected. This report is to be submitted annually for plants that are within 5 years of the end of licensed operations. 10 CFR 50.75 (f)(i) also requires that each power reactor licensee shall report the status of its decommissioning trust fund annually if the facility has already closed (before the end of its licensed life).

In addition to the financial assurance requirements for decommissioning in 10 CFR 50.75, other requirements in 10 CFR 50.75 and 50.82 specify requirements for submitting cost estimates for decommissioning to the NRC:

- 10 CFR 50.75(f)(2) requires that a licensee shall, at or about 5 years prior to the projected end of operations, submit a preliminary decommissioning cost estimate.
- 10 CFR 50.82(a)(4)(i) requires a licensee to provide an estimate of expected costs for the activities being proposed in the PSDAR.
- 10 CFR 50 82(a)(8)(iii) requires a licensee to provide a site-specific decommissioning cost estimate within 2 years following permanent cessation of operations.
- 10 CFR 50.82(a)(9)(ii)(F) requires a licensee to provide an updated site-specific estimate of remaining decommissioning costs as part of its LTP.

The regulations in 10 CFR 50.82 also specify the criteria that a licensee must meet before they can withdraw funds from the decommissioning fund for decommissioning activities.

4.3.11.2 Potential Impacts of Decommissioning Activities on Cost

As indicated in Table E-3 in Appendix E, all aspects of decommissioning will have an impact on decommissioning costs. The potential impacts of decommissioning activities on cost vary due to the cost of waste management and disposal of the LLW generated during decommissioning and to the uncertainty associated with regulatory requirements.

The variability in waste management and disposal arises because the Barnwell Low-Level Radioactive Waste Management Disposal Facility, the last remaining facility that is available to dispose of all classifications of LLW generated by all but two nuclear power facilities located throughout the United States, is scheduled to stop accepting waste from all NRC licensees except those located in the Atlantic Compact by 2009 (see NUREG-1307, Rev. 9, *Report on Waste Burial Charges* [NRC 2000]). However, decommissioning of most of the nuclear power facilities in the United States is not expected to occur until sometime after 2009. This cost uncertainty is generally applicable to most of the nuclear power facilities that are currently being decommissioned and those that will be decommissioned in the future. This cost uncertainty, however, is somewhat mitigated by the availability of the Envirocare disposal facility in Utah. Envirocare can accept most Class A LLW for disposal from any generator in the United States. (More than 95 percent of LLW generated during nuclear power facility decommissioning is Class A.) Other LLW storage and disposal sites are also currently being proposed.

The uncertainty associated with regulatory requirements is a reflection of the different requirements and standards for cleanup applied by different States and localities. While NRC cleanup requirements for terminating a license are well defined, these other external requirements may significantly influence the cost of decommissioning. For example, local jurisdictions might impose additional requirements than those imposed by the NRC. The cost of the extra cleanup is not reflected in the decommissioning fund required by the NRC.

4.3.11.3 Evaluation

The estimated cost of decommissioning all of the nuclear power facilities that have been built and operated in the United States is provided in Table 4-3 (in January 2001 dollars). The costs provided in the table are those estimated by the owners of the individual plants and reported to the NRC.

Shown in the table are the actual costs to complete the decommissioning and terminate the 10 CFR Part 50 licenses for each of those facilities that have reached this milestone of their life-cycle. Facility-specific estimates are also provided for each plant that has been permanently shut down and is either actively undergoing decommissioning or is in safe storage awaiting active decontamination and dismantlement. The costs shown are estimates developed by the licensee and reported in their PSDARs, site-specific cost estimate reports, LTPs, etc. These estimates are adjusted to January 2001 dollars.

Table 4-3 provides the range of costs estimated by utilities to decommission all of the nuclear power facilities that are currently operating or have not indicated an intent to permanently shut down. Cost ranges, rather than facility-specific cost estimates, are provided for these plants, reflecting the fact that these estimates are not as well developed as for those plants that have already permanently shut down. These cost ranges were developed from licensee-provided estimates in the March 1999 biennial decommissioning reports adjusted to January 2001 dollars.

Finally, Table 4-3 provides a range of decommissioning cost estimates for the ENTOMB options. These options have not been used or considered by any U.S. nuclear power facility licensee to date. Cost estimation methods for the ENTOMB options are, thus, not as well developed as for the DECON and SAFSTOR methods. The values quoted in the table were developed from an analysis of the two entombment scenarios described in Chapter 3 for a "reference" (i.e., typical) PWR and BWR. The reference PWR was assumed to be the Trojan Plant in Oregon; the reference BWR was assumed to be the Columbia Generating Station in Washington.

The cost of decommissioning results in impacts on the price of electricity paid by ratepayers. These impacts generally occur over the life of the facility as the decommissioning fund is being collected. However, for those nuclear reactor facilities that shut down prematurely (as is the case for the majority of the facilities identified in Table 4-3), the impact may also occur for a number of years after permanent shutdown while the under-collected portion of the fund continues to be collected.

This analysis assesses the impact of cost by evaluating the total cost to decommission a nuclear power facility and terminate its Part 50 license. This impact is summarized in Table 4-4. As can be seen, the cost to decommission a large (>200 MWe) nuclear power facility is estimated to range from $150 million to $700 million and is highly dependent on the factors discussed previously.

4.3.11.4 Conclusions

The staff has reviewed these data, recognizing that an evaluation of decommissioning cost is not a NEPA requirement. This information is presented here as a summary of actual and predicted decommissioning costs based on recently available data.

4.3.12 Socioeconomics

There are two primary pathways through which nuclear power plant activities create socioeconomic impacts on the area surrounding the plant. The first is through expenditures in the local community by the plant work force, and direct purchases of goods and services required for plant activities. The second pathway for socioeconomic impact is through the effects on local government tax revenues and services. When a nuclear power plant is closed and decommissioned, most of the important socioeconomic impacts will be associated with the plant closure rather than with the decommissioning process.

4.3.12.1 Regulations

There are no Federal or State regulations pertaining to any particular level of socioeconomic impacts, as there are for some environmental effects. Socioeconomic impacts are an element of NEPA documentation that must be addressed and mitigated, if warranted.

4.3.12.2 Potential Impacts of Decommissioning Activities on Socioeconomics

As indicated in Table E-3 in Appendix E, all of the socioeconomic impacts of decommissioning are related to organizational or staffing changes. The impacts of decommissioning were assessed recognizing that the potentially large impacts of plant closure may occur simultaneously with those of the actual decommissioning activities. However, as indicated in Section 1.3, impacts related to the decision to permanently cease operations are outside the scope of this Supplement.

Socioeconomic changes related to direct expenditures in the local community are considered not detectable if there is little or no impact on housing values, education and other public services, and local government finances, are not distinguishable from normal background variation due to other causes. Impacts on housing are considered not detectable when no discernable change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and little or no housing construction or conversion

Table 4-3. Cost Impacts of Decommissioning (in January 2001 Dollars)

Nuclear Plant	Electric Power Generation Rating	Reactor Type	Decommissioning Option	Estimated Decommissioning Cost, $ million
Decommissioning Completed				
Fort St. Vrain	330 MWe	HTGR	DECON	230 (189 [1996])[a]
Pathfinder	59 MWe	BWR	SAFSTOR	20 (13 [1992])[a]
Shoreham	809 MWe	BWR	DECON	258 (182 [1994])[a]
Currently Being Decommissioned				
Big Rock Point	67 MWe	BWR	DECON	364
Dresden, Unit 1	200 MWe	BWR	SAFSTOR	340
Fermi, Unit 1	61MWe	FBR	SAFSTOR	36
GE-VBWR	13 MWe	BWR	SAFSTOR	10
Haddam Neck	619 MWe	PWR	DECON	404
Humboldt Bay, Unit 3	65 MWe	BWR	SAFSTOR	284
Indian Point, Unit 1	257 MWe	PWR	SAFSTOR	259
La Crosse	50 MWe	BWR	SAFSTOR	111
Maine Yankee	860 MWe	PWR	DECON	400
Millstone, Unit 1	660 MWe	BWR	SAFSTOR	563
Peach Bottom, Unit 1	40 MWe	HTGR	SAFSTOR	65
Rancho Seco	913 MWe	PWR	SAFSTOR	394
San Onofre, Unit 1	410 MWe	PWR	SAFSTOR	427
Saxton	NA	PWR	SAFSTOR	44
Three Mile Island, Unit 2	792 MWe	PWR	SAFSTOR	502
Trojan	1130 MWe	PWR	DECON	250
Yankee Rowe	167 MWe	PWR	DECON	244
Zion, Unit 1	1085 MWe	PWR	SAFSTOR	386
Zion, Unit 2	1085 MWe	PWR	SAFSTOR	495
Currently Operating				
69 PWR Reactors	486 - 1270 MWe	PWR	DECON/SAFSTOR	264 - 695
35 BWR Reactors	514 - 1265 MWe	BWR	DECON/SAFSTOR	152 - 663
"Reference PWR"	1130 MWe	PWR	ENTOMB1/ ENTOMB2	290 - 400
"Reference BWR"	1100 MWe	BWR	ENTOMB1/ ENTOMB2	410 - 750

(a) Actual cost to complete the decommissioning and the year the license was terminated.

Table 4-4. Summary of Cost Impacts by Decommissioning Option and Reactor Type and Size (January 2001 Dollars)

	Decommissioning Cost Range, $million					
Decommissioning Option	**PWR < 200 MWe**	**PWR ≥ 200 MWe**	**BWR < 200 MWe**	**BWR ≥ 200 MWe**	**HTGR**	**FBR**
DECON	244	250 - 404	364	>182[a]	189	--
SAFSTOR	44	259 - 597	13 - 284	340 - 563	65	36
DECON/SAFSTOR (currently operating reactors)	--	264 - 695	--	152 - 663	--	--
ENTOMB1/ENTOMB2	--	290 - 400	--	410 - 750	--	--

(a) Cost data from the Shoreham plant, which only generated one effective full power day. There was little or no contamination to many plant systems. Not representative of other large BWRs.

occurs. Detectable impacts result when there is a discernable increase or reduction in housing availability, rental rates and housing values exceed the inflation rate elsewhere in the State, or more than minor housing conversions and additions or abandonments occur. Destabilizing impacts occur when project-related demand results in a very large excess of housing or very limited housing availability, where there are considerable increases or decreases in rental rates and housing values, or when substantial conversion or abandonment of housing units occurs.

Socioeconomic changes related to tax revenues and services (education, transportation, public safety, social services, public utilities, and tourism and recreation) are considered not detectable if the existing infrastructure (facilities, programs, and staff) could accommodate changes in demand related to plant closure and decommissioning without a noticeable effect on the level of service. Detectable impacts arise when the changes in demand for service or use of the infrastructure is sizeable and would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new local government programs, upgraded or new facilities, or substantial numbers of additional staff and unsupportable levels of resources are required because of facility-related demand.

4.3.12.3 Evaluation

The size of the work force varies considerably among operating U.S. nuclear power facilities, with the onsite staff generally consisting of 600 to 800 personnel per reactor unit. The average permanent staff size at a nuclear power facility ranges from 600 to 2400 people, depending on the number of operating reactors at the site. In rural or low-population communities, this number of permanent jobs can provide employment for a substantial portion of the local work

force. In addition to the work force needed for normal operations, many temporary personnel are required for various tasks that occur during outages. Between 200 and 900 additional workers may be employed during these outages to perform the normal outage maintenance work. These are work force personnel who may be in the local community only a short time, but during these periods of extensive maintenance activities, the additional personnel could have a substantial effect on the locality. If, as expected, the decommissioning process requires a smaller work force than the onsite operating staff (typically 100 to 200 staff) and if the local economy is stable or declining, the result of the reduction in work force related to plant closure could be economic hardships, including declining property values and business activity, and problems for local government as it adjusts to lower levels of tax revenues. However, even the small decommissioning work force will tend to mitigate temporarily the full adverse socioeconomic effects of terminating operations.

If there is a net reduction in the community work force but the economy is growing, the adverse impacts of this ongoing growth (e.g., housing shortages and school overcrowding) could be reduced.

If the decommissioning work force were substantially larger than the operating work force, the result could be increased demand for housing and public services but also increased tax revenues and higher real estate values. If the economy is characterized by decline, then decommissioning could temporarily reverse the adverse economic effects.

In a stable economy, a net increase in the community work force could lead to some shortages in housing and public services, as well as to the higher tax revenues and real estate values mentioned previously. In a growing economy, decommissioning could act as an exacerbating factor to the ongoing shortages that already might exist.

Changes in work force and population: Changes of over 3 percent to local population in a single year are expected to have detectable effects, while changes of over 5 percent are expected to result in destabilizing impacts. These negative impacts include reduction of school system enrollments, weakened housing markets, and loss of demand for goods and services provided by local businesses. The size of the work force required during decommissioning, relative to that during operations, is an important determinant of population growth or decline.

The impact from facility closure depends on the rate and amount of population change. If decommissioning begins shortly after shutdown with a large work force, then the impact of facility closure is mitigated. Facilities where layoffs are sudden and there is a long delay before active decommissioning begins are more likely to experience negative population-related socioeconomic impacts. Thus, large plants located in rural areas that permanently shut down early and choose the SAFSTOR option are the likeliest to have negative impacts. Considering all variables such as plant size and community size as the same, plants that go into immediate

DECON have less immediate negative impacts; the impacts from the ENTOMB option, assuming those preparations were made immediately after shutdown, would be less significant than those of SAFSTOR.

Data on changes in work force were collected at facilities that are being decommissioned where information on operational and decommissioning work force is available. This information is presented in Appendix J, Table J-1. The table also shows total population in the host county at the time of plant shutdown, to indicate the potential importance of the facility closure.

In order to identify any unusual downward trends in county population around the time of a facility shutdown, data were collected showing the range of percentage changes in population that have occurred at facilities currently being decommissioned. U.S. Census population data for the counties that house the decommissioning facility are used to assess changes in population around the time of shutdown by comparing percentage changes in the county population with State population changes during the same time period. This information is provided in Appendix J, Table J-2.

In only two cases did the corresponding county populations decline around the time of the closure (Indian Point, Unit 1, in Westchester, New York, and Millstone, Unit 1, in New London, Connecticut). However, during the same time period that the host counties experienced population declines, the hosting States also experienced population declines. This suggests that the decline in the county population was part of an overall State population trend. Observing population trends over a decade may not capture small population declines or reductions in the rate of growth from one year to the next; however, longer trends should indicate whether or not the county had any large destablizing population or housing impacts from the facility closure.

In 18 out of the 20 facility case studies where populations grew, the populations of the counties where the facilities are located increased more rapidly or at the same rate as the State population. The two cases where the populations of the counties grew at a slower rate include relatively rural counties in California (Humboldt and Alameda) during time periods when the State of California experienced very high urban population growth. In general, experience of decommissioning facilities to date does not show any impacts from population change, either because the closure-related changes were small relative to the population base or because they were offset by other growth in the area.

Local tax revenues: Changes in tax revenues of less than 10 percent are considered not detectable, i.e., they result in little or no change in local property tax rates and the provision of public services. Losses between 10 percent and 20 percent result in detectable impacts, with increased property tax levies (where State statutes permit) and decreased services by local municipalities. Changes over 20 percent have destabilizing impacts on the governments involved. Tax levies must usually be increased or services cut substantially, and the payment of debt for any substantial infrastructure improvements made in the past becomes problematic.

Borrowing costs for local jurisdictions may also increase because bond rate agencies downgrade their credit rating. However, it is important to remember that these rules of thumb are based on uncompensated changes. For example, if a local taxing jurisdiction lost a nuclear facility that amounted to 35 percent of its tax base, but 30 percentage points of this loss were made up by the opening of a new manufacturing facility, the net impact would be 5 percent or not detectable. Small, rural areas are more likely to be affected than more urban areas having a wider variety of economic opportunities and more sources of tax revenue. Impacts depend on the type of plant, size of plant, and whether or not there are multiple units at a site, all of which help determine the net loss in employment at plant closure as well as the loss of tax base.

More information is available for facilities that have recently closed than for facilities closed more than 10 years ago (see Appendix J, Table J-3). The findings from this body of evidence confirm the findings discussed above. The primary taxing authorities for most of the decommissioning plants are the county and city in which the facility is sited. Tax information is typically provided by local taxing authorities (assessor's office) or from town planners familiar with the tax revenues generated by the facility.

The tax revenue impacts on the local communities of facility closure range from zero impact (tax-exempt plants) to loss of 90 percent of the community tax base. The magnitude of tax-related impacts varies primarily by the size of the taxing jurisdiction and the taxing structure of the State in which the plant is sited, as well as certain plant characteristics. Hence, the smaller the taxing community (less economically diverse), the greater the tax revenue impact when the nuclear facility closes down.

In communities where the revenues from the facility made up over 50 percent of the tax revenue base (with the remaining tax revenues made up primarily of private residential real estate), there were significant increases in the tax rates on the remaining real estate as well as cut-backs in services provided by property-tax revenues. The manner in which a State calculates the value of the plant also affects both the amount and timing of tax losses when a nuclear power facility closes and how much such a closure disrupts the tax revenue stream in a given community:

- At one plant, the assessed value of the plant was calculated as a proportional share of the value of the parent corporation, where the percentage is based on the book value of assets in the State (or sub-State taxing jurisdiction) compared with the book value of the assets of the entire corporation. This approach kept the plant at full assessed value for 7 years after its permanent closure until it was dropped from the books of the parent corporation as an asset. Several other approaches are discussed in Appendix J.

- Tax rules may or may not permit gradual phase-out. In some cases, the taxable asset value of the plants was allowed to phase out over a period of time (3 to 5 years). In other cases, the plants were simply taken off the tax roles in 1 year.

- The State may or may not share the burden with local government. In one State, school districts' lost property-tax collections were offset by equalization methods at the State level, which reduced the impact due to plant closures. In another State, the small neighboring township was the sole recipient of all property-tax revenues generated by the plant. Thus, the community's tax revenues were significantly reduced when the revenue source shut down.

- Utility ratepayers in some jurisdictions are entitled to share in funds recovered from sale of plant components and commodities and unspent decommissioning funds. These are not taxes but are available to general fund revenues.

In addition to characteristics specific to the taxing jurisdiction, the size, age, and ownership of the facilities play a role in how much the facilities affect tax revenues. Generally, the larger the facility (MWt), the larger the tax revenue impact. In addition, aging of the facility depreciates its book value and its assessed value over time. Usually, the falling assessed value of an aging facility will have reduced the tax revenue of the facility before closure, thus lessening the change in tax revenues generated by the facility after closure. A facility that closes suddenly, well before the end of its license expiration, will have a greater impact on the community tax base. Finally, if a facility is owned by a public entity, there is no effect on the tax base from closure because the facility was never taxable.

The choice of the decommissioning option appears to have had no bearing on the loss of tax receipts. The impact has to do with the size and suddenness of the loss of tax revenue (size and age of facility) related to plant closure only. The length of delay between shutdown and decommissioning does not appear to affect the size of the impact on tax revenue losses. No commercial nuclear power reactor has used the ENTOMB options, but there is no reason to expect ENTOMB to have any different impact on tax revenue losses than SAFSTOR or DECON.

Public services: The impacts of decommissioning on public services are generally much smaller than the impacts of plant closure. Impacts of closure are closely related to the tax-related impacts on the community and are affected by the same characteristics of the plant (size and age, tax treatment, and dependence of the local community on plant-related revenues), but not on the choice of decommissioning option or the amount of time between shutdown and active decommissioning. Inquiries were made to local governments in the vicinity of closed plants about public service impacts during and after shutdown and decommissioning. Their assessments are discussed in Appendix J and data are shown in Table J-4. Analysis was also conducted in the course of preparing NUREG-1437 (NRC 1996). Based on that experience, the following generalizations can be made.

Detectable impacts on housing result when there is a discernable increase or reduction in housing availability, when rental rates and housing values exceed the inflation rate elsewhere in the State, or when minor housing conversions and additions or abandonments occur.

Destabilizing impacts occur when project-related demand results in a very large excess of housing or very limited housing availability, where there are considerable increases or decreases in rental rates and housing values, and when there is substantial conversion or abandonment of housing units. The prevailing belief of realtors and planners in communities surrounding the case study facilities is that closing the facilities has had a range of effects on the marketability or value of homes in the vicinity. Housing choices of local residents are rarely affected by the presence of the facility, but people may move into the area in response to (temporarily) softer housing prices and commute to a nearby urban area. However, the decommissioning process itself does not appear to have produced any detectable impacts on housing.

The impacts to the following public services may occur as a result of plant closure: education, transportation, public safety, social services, public utilities, and tourism and recreation.

In general, detectable impacts arise when the demand for service or use of the infrastructure is sizeable. Impacts would noticeably decrease the level of service or require additional resources to maintain the level of service. Destabilizing impacts would result when new programs, upgraded or new facilities, or substantial additional resources and staff are required because of facility-related demand. Specific information for each of the areas of public service for closed plants is provided in Appendix J.

In general, the communities that suffered the most from the tax-related impacts of plant closure also experienced the greatest impacts on public services. To some extent, the communities themselves control the amount of impact by how they allocate property taxes to local budgets before shutdown, and how they prioritize these services post-shutdown. For example, one community channeled a great deal of the surplus revenues into building extensive social services for the elderly and for local youth in its community. After the plant ceased operations, the tax revenues decreased, all of the social services were downsized, and many will have to be eliminated because they are not considered priority programs (relative to public safety and education). In a second case, the county provided relatively few social services. Thus, the impact on social services after the shutdown was minor, although several other categories of public service experienced larger impacts. For example, education was largely funded by plant tax revenues and the responsible school district has recently indicated that it may have to file for bankruptcy, so the impact there was substantial[(a)]. However, all of these impacts were related to plant closure; in no case did the decommissioning process itself result in detectable impacts on public services.

(a) The size of impact can be significantly influenced by the mechanism that the State uses for funding, e.g., if the State makes up the difference between what the local school districts can fund from the local property tax and what the State has decided is the appropriate level of per-student expenditures.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on socioeconomics that are different from those found at other nuclear facilities.

Summary: The impacts of plant closure are those that are observed by the community, rather than the impacts from decommissioning activities because they occur at about the same time. The impacts occur either through changing employment levels and local demands for housing and infrastructure, or through decline of the local tax base and the ability of local government entities to provide public services. The effects of employment changes on population growth are expected to be not detectable if population changes (reductions or increases) are less than 3 percent per year, detectable but not destabilizing if the population change is between 3 percent and 5 percent, and destabilizing if the population change is greater than 5 percent per year. Experience so far has shown that in most cases, reductions in employment related to plant closure even at fairly large sites do not generally produce local population changes greater than 3 percent, regardless of the type of plant and decommissioning option selected. The impacts of the decommissioning work force are even smaller.

The effect on the local tax base and public services related to closure depends on the size of the plant-related tax base relative to the overall tax base of local government, as well as on the rate at which the tax base is lost. Changes in annual tax revenues less than about 10 percent are considered nondetectable, i.e., they result in little or no change in local property tax rates and the provision of public services. Losses between 10 percent and 20 percent result in detectable but not destabilizing impacts, with increased property tax levies (where State statutes permit) and decreased services by local municipalities. Changes over 20 percent have destabilizing impacts on the governments involved. Experience has shown that publicly owned tax-exempt plants will not have an impact through this mechanism. In addition, fully depreciated plants, or a plant that is located in an urban or urbanizing area with a large or rapidly growing tax base will also not be impacted by this mechanism. A large, newer, relatively undepreciated plant, located in a small, isolated community, is much more likely to exceed the 20-percent criterion. If the plant tax base is phased out slowly after closure in these circumstances, the impact is more likely to be mitigated. Neither the type of reactor nor the method chosen for decommissioning matters.

Decommissioning itself has no impact on the tax base and no detectable impact on the demand for public services.

4.3.12.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning on socioeconomics. This information indicates that the impacts of decommissioning on socioeconomics are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on socioeconomics are SMALL. The staff has considered mitigation and concludes

that no additional measures are likely to be sufficiently beneficial to be warranted.

4.3.13 Environmental Justice

An evaluation of environmental justice is performed to determine if minority and/or low-income groups bear a disproportionate share of negative environmental consequences. Executive Order 12898, dated February 16, 1994 (59 FR 7629), directs Federal executive agencies to consider environmental justice under NEPA. The Executive Order does not create whole new categories of impacts that need to be considered; nor does it create any right, benefit, or trust responsibility, substantive or procedural, that can be enforced by law or equity. It is designed to improve internal management of agencies to ensure that low-income and minority populations do not experience disproportionately high and adverse human health or environmental effects because of Federal actions.

Environmental justice has not been evaluated previously for decommissioning activities at reactor facilities.

4.3.13.1 Regulations

The CEQ has provided *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ 1997). Although NRC is an independent agency, the Commission has committed to undertake environmental justice reviews, and has provided specific information in Office Instruction LIC-203, Nuclear Reactor Regulation (NRR), *Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues* (NRC 2001a). The CEQ guidance and NRR instructions provide several key definitions and the framework for analysis.

Low-income population: Low-income populations in an environmental impact area should be identified where census block groups within the environmental impact area have (1) more than 50 percent low-income persons or (2) the percentage of persons in households below the poverty level is significantly greater (typically, at least 20 percentage points) than in the geographical area chosen for comparative analysis. In identifying low-income populations, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a set of individuals (e.g., migrant workers or American Indians[a]), where either type of group experiences common conditions of environmental exposure or effect.

Minority: Individuals who are members of the following population groups: American Indian and Alaska Native; Asian; Native Hawaiian and other Pacific Islander; Black or African

(a) For consistency, the term "American Indian" is used throughout this document to conform to the definition of "minority population."

American, not of Hispanic or Latino origin; or some other race and Hispanic or Latino (of any race).[a]

Minority population: According to the CEQ, minority populations should be identified where either (a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage of the affected area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis. In identifying minority communities, agencies may consider as a community either a group of individuals living in geographic proximity to one another or a geographically dispersed/transient set of individuals (e.g., migrant workers or American Indians), where either type of group experiences common conditions of environmental exposure or effect. The selection of the appropriate unit of geographic analysis may be a governing body's jurisdiction, a neighborhood, census tract, or other similar unit that is to be chosen so as not to artificially dilute or inflate the affected minority population. A minority population also exists if there is more than one minority group present and the minority percentage, as calculated by aggregating all minority persons, meets one of the above-stated thresholds. NRR adopted a standard of 20 percentage points as "meaningfully greater."

Disproportionately high and adverse human health effects: When determining whether human health effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether the health effects, which may be measured in risks and rates, are significant (as used by NEPA), or above generally accepted norms (adverse health effects may include bodily impairment, infirmity, illness, or death); (b) whether the risk or rate of hazard exposure by a minority or low-income population, to an environmental hazard is significant (as used by NEPA) and appreciably exceeds or is likely to appreciably exceed the risk or rate to the general population or other appropriate comparison group; and (c) whether health effects occur in a minority or low-income population, affected by cumulative or multiple adverse exposures from environmental hazards.

Disproportionately high and adverse environmental effects: When determining whether environmental effects are disproportionately high and adverse, agencies are to consider the following three factors to the extent practicable: (a) whether there is or will be an impact on the natural or physical environment that significantly (as used by NEPA) and adversely affects a minority or low-income population (such effects may include ecological, cultural, human health, economic, or social impacts on minority communities, low-income communities, or American Indian tribes when those impacts are interrelated to impacts on the natural or physical environment); (b) whether environmental effects are significant (as used by NEPA) and are or may be having an adverse impact on minority populations, low-income populations, or

(a) "Other" may be considered a separate minority category. In addition, the 2000 Census included multi-racial data. Multi-racial individuals should be considered in a separate minority, in addition to the aggregate minority category.

American Indian tribes that appreciably exceeds or is likely to appreciably exceed those on the general population or other appropriate comparison group; and (c) whether the environmental effects occur or would occur in a minority or low-income population, affected by cumulative or multiple adverse exposures from environmental hazards.

4.3.13.2 Potential Impacts of Decommissioning Activities on Environmental Justice

As indicated in Table E-3 in Appendix E, decommissioning activities that may affect environmental justice are related to organizational or staffing changes and offsite transportation issues. However, the assessment of environmental justice is related to most of the other specific issues discussed throughout this Supplement. Any decommissioning activity that results in a disproportionate share of negative environmental consequences to minority or low-income groups has the potential to be an adverse environmental justice impact.

Detectability and destabilization, as they relate to environmental justice, must be defined in proportion to the minority and low-income populations that reside in the area of the power plant. Proportionment must be determined at each site at the time of decommissioning.

4.3.13.3 Evaluation

Most of the environmental justice impacts relate to land use, environmental and human health, and socioeconomics. Impacts due to onsite land disturbance are likely to be not detectable because the amounts of land disturbance are generally very small and usually occur in areas of the site previously disturbed by construction or operation of the facility. Impacts from disturbances to offsite land will generally not occur because offsite land generally is not disturbed as a result of decommissioning. If offsite land disturbance is required (e.g., if a new offsite road or rail spur is needed to transport large components or waste from decommissioning), the impact on environmental justice is site-specific because it will depend on the location of the new route relative to low-income populations or other affected resources on which they may depend. Some minority and low-income populations normally live along rail lines and truck routes. Previous transportation analyses have found that the impacts would be small from normal operations or from accidents. Thus, no disproportionately high and adverse effects are expected for any particular segment of the population, including minority and low-income populations, that may live along proposed rail and truck routes. Siting and construction of these offsite transportation upgrades would include an evaluation of cultural and other resources in the disturbed areas. Usually, offsite physical environmental impacts of decommissioning will be not be detectable because offsite environmental impacts from decommissioning are generally not detectable.

Socioeconomic impacts on minority and low-income populations due to plant closure could range from nondetectable to destabilizing, depending on the distribution of job impacts within the community and the effects of plant closure on local tax revenues and public services; however, the impact of decommissioning would generally not be detectable. More generic

information on overall socioeconomic impacts can be obtained by observing demographic statistics. In the 21 decommissioning case studies observed, it was concluded that facility closure would not have a detectable socioeconomic impact on low-income and minority populations. In other words, there appears to be no indication that minority or low-income populations would suffer disproportionately high and adverse impacts from the closure of the facilities. Because decommissioning has even smaller effects, its impact also would have been not detectable. The environmental justice conclusions are based on demographic information, i.e., the overall impact of the facility on the community. Discussions were also held with community members at some sites.

In addition, information provided by local government and social service providers helps determine the socioeconomic impacts on low-income and minority populations. In many of these case studies, the nuclear facilities are located in primarily white communities and tend to be located near bodies of water where upper-income real estate is built. Those that are employed by the facility tend to fall into the upper-income bracket within the communities where the facilities are located. Selected socioeconomic indicators are found in Appendix J, Table J-5, for the closed nuclear power plants studied.

The determination of whether the minority or low-income populations are disproportionately highly and adversely impacted by facility decommissioning activities needs to be made on a site-by-site basis because their presence and their socioeconomic circumstances will be site-specific. Data indicate there is no reason to expect adverse socioeconomic impacts to be correlated with type of plant (see Table J-5). However, adverse socioeconomic impacts are correlated with large facility size, early shutdown, and small, isolated host communities. If minority and low-income populations are present, adverse impacts from facility closure would be somewhat more likely in small, isolated communities than in larger urban areas. It is not clear whether these effects would be disproportionately high and adverse.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in environmental justice considerations that are different from those found at other nuclear facilities.

4.3.13.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on environmental justice, including comments received on the draft of Supplement 1 of NUREG-0586. Based on this information, the staff has concluded that the adverse impacts and associated significance of the impacts must be determined on a site-specific basis. Executive Order 12898 (59 FR 7629), dated February 16, 1994, directs Federal executive agencies to consider environmental justice under the National Environmental Policy Act 1969 (NEPA). Although the NRC is an independent agency, the Commission has committed to undertake environmental justice reviews. Subsequent to the submittal of the PSDAR, the NRC staff will consider the impacts related to environmental justice from decommissioning activities.

4.3.14 Cultural, Historic, and Archeological Resources

Cultural resources include any prehistoric or historic archeological site or historic property, site, or district listed in or eligible for inclusion in the National Register of Historic Places or otherwise having significant local importance. The Federal agency (in this case the NRC) is responsible for the evaluations through consultations with the State Historic Preservation Officer (SHPO), or if appropriate, the Tribal Historic Preservation Officer (THPO), that is responsible for determining which sites or properties are of significant historic or archeological importance. The NRC is also responsible for including other interested parties and affected American Indian tribes. Disagreements between the parties are resolved by the Advisory Council on Historic Preservation.

Evaluation of the potential presence of cultural resources should not rely solely on a query of the SHPO database, but should be based on field surveys and evaluations of the site. Although these evaluations may have been performed as part of the initial environmental evaluation for the sites or as part of another licensing action (e.g., license renewal), the coverage and adequacy of earlier survey efforts needs to be re-evaluated in cases where an impact may occur. Earlier field surveys and methods may not conform to current standards.

4.3.14.1 Regulations

The Federal statute that is most directly applicable to cultural resource issues during the decommissioning process is the National Historic Preservation Act (NHPA) of 1966 as amended (16 USC 470 et seq.). This Act created the National Register of Historic Places (National Register) and requires the heads of all Federal agencies to consider the impacts of the undertakings on any cultural properties that are listed on the National Register or that are eligible for listing. Section 106 of the NHPA requires each Federal agency to identify, evaluate, and determine the effects of an undertaking on any cultural resource site that may be within the area impacted by that undertaking. This section also requires consultation to resolve adverse effects of an undertaking and establishes mechanisms to obtain and incorporate comments from consulting parties. Federal agencies are directed by 36 CFR Part 800 to comply with the stipulations of NHPA as well as pertinent cultural, historical, and archeological protection provisions of NEPA, the Historic Sites Act of 1935, and the Antiquities Act of 1906 and their implementing regulations. The Historic Sites Act of 1935 (16 USC 461-467) declared a national policy of preserving for the public historic sites, buildings, and objects of national significance. It also led to the establishment of the Historic Sites Survey, the Historic American Buildings Survey, and the Historic American Engineering Record within the National Park Service.

Most other cultural, historical, and archeological protection regulations are primarily directed at resource protection on Federal lands, but in some cases these statutes may be applicable to the decommissioning of commercial power reactors. Several commercial nuclear power reactors are located on Federal lands. The Antiquities Act of 1906 (16 USC 431-433) prohibits destruction of vertebrate fossils and archeological sites on Federal lands and regulates their

removal under a permitting procedure. These regulations were further strengthened by the Archeological Resources Protection Act of 1979 (16 USC 470aa-47011), which prohibits the willful or knowing destruction and unauthorized collection of archeological sites and objects located on Federal lands. It also establishes a permitting system for archeological investigations and requires consultation with concerned tribes prior to permit issue. The Native American Graves Protection and Repatriation Act of 1990 (25 USC 3001 et seq.) protects graves on Federal lands and establishes tribal ownership of human remains and/or associated funerary objects taken from Federal lands and requires the inventory and repatriation to the tribes of any remains or funerary objects held by Federal agencies. Certain more recent Executive Orders regarding consultation with American Indian tribes and protection of religious sites and values could also be relevant.

Many of the States also have statutes that protect cultural, historical, and archeological resources on State lands. Some States also have burial and cemetery statutes that apply to private land as well. These State-level statutes are usually administered through the appropriate SHPO.

4.3.14.2 Potential Impacts of Decommissioning Activities on Cultural, Historic, and Archeological Resources

As indicated in Table E-3 in Appendix E, decommissioning activities that have a potential to adversely impact cultural resources include stabilization, decontamination and dismantlement, and large component removal. These activities adversely impact cultural resources primarily via land disturbance, which could damage or destroy the resource, or alter the contextual setting of the resource. In addition to the direct effects of land clearing, indirect effects such as erosion and siltation may adversely affect some cultural resources. Decommissioning activities also may alter the site access and administrative protection of the resources.

In a few situations, the nuclear facility itself could be potentially eligible for inclusion in the National Register of Historic Places, especially if it is older than 50 years and represents a significant historic or engineering achievement. In this case, appropriate mitigation would be developed in consultation with the SHPO. Even for buildings that are less than 50 years old, the processes and engineering that were employed may be of interest and may be eligible for the Historic American Engineering Record.

Impacts to cultural, historical, or archeological resources are considered detectable if the activity has a potential to have a discernable adverse affect on the resources. The impacts are destabilizing if the activity would degrade the resource to the point that it would be of significantly reduced value to the future generations, such as physically damaging structures or artifacts or destroying the physical context of the resource in its environment.

4.3.14.3 Evaluation

In most cases, the amount of land required to support the decommissioning process is relatively small and is a small portion of the overall plant site. Usually, the areas disturbed or utilized to support decommissioning are within the operational areas of the site and typically are within the protected area. Usually, there is sufficient room within the operational areas to function as temporary storage, laydown, and staging sites. In most cases, management, engineering, and administrative staff would be assigned space in existing support or administration buildings. In some cases, the licensees have installed trailers or temporary buildings to house engineering and administrative staff or to otherwise support decommissioning. In most cases examined, the licensees expect to restrict decommissioning activities to highly disturbed operational areas but a few do expect to use lands beyond the operational areas. The licensees typically anticipate utilizing an area of between 0.4 ha (1 ac) to approximately 10.5 ha (26 ac) to support the decommissioning process. One facility (Big Rock Point) required a new transmission line right of way (ROW) to provide electrical power to the plant site during decommissioning (this line will also provide power to the onsite independent spent fuel storage installation [ISFSI] after decommissioning is completed). However, construction of a new transmission line ROW is considered an unusual situation. It is expected that some sites will require the reconstruction or installation of new transportation links, such as railroad spurs, road upgrades, or barge slips. Activities conducted within the operational areas are not expected to have a detectable effect on important cultural resources because these areas have normally been highly degraded during facility construction and operation. Activities conducted outside of the operational areas may have detectable impacts, depending on the size and type of impact, and the cultural resources potentially affected.

The potential for adverse impacts is probably not affected by the type of facility (BWR, PWR, HGTR, or FBR) or the decommissioning option selected. However, the different decommissioning options are likely to alter the timing of the impact to cultural resources more than the magnitude of the impacts. DECON may require slightly more land area to support a larger number of activities occurring at the same time. ENTOMB2 would probably have the least likelihood of adverse impacts because some large components may be left in place, reducing the land requirements needed for large construction equipment, as well as waste storage and barge or rail loading areas. The potential impacts of SAFSTOR may be smaller than DECON or ENTOMB1, depending on the time period over which activities are performed. If dismantling and decontamination occur slowly over many years (incremental decontamination and dismantlement), the same storage and staging areas can be reused for sequential activities; however, if many activities are performed over a short time period at the end of the SAFSTOR period, the impacts may be as large as DECON.

4.3.14.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on cultural, historic, and archeological resources, including comments received on the draft of

Supplement 1 of NUREG-0586. For plants where the disturbance of lands beyond the operational areas is not anticipated, the impacts on cultural, historic, and archeological resources are not considered to be detectable or destabilizing. Therefore, the staff makes a generic conclusion that for such plants, the potential impacts to cultural, historic, and archeological resources are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

If disturbance beyond the operational areas is anticipated, the impacts may or may not be detectable or destabilizing, depending on site-specific conditions, and cannot be predicted generically. Therefore, the staff concludes that if disturbance beyond the operation areas is anticipated, the potential impacts may be SMALL, MODERATE, or LARGE and must be determined through site-specific analysis. Before the licensee conducts any decommissioning activity that might result in the disturbance of historic properties or archeological resources outside the site operational area, the NRC will, in accordance with the National Historic Preservation Act of 1966 as amended (16 USC 470 et seq.), consult with the appropriate SHPO or THPO to evaluate potential impacts.

4.3.15 Aesthetic Issues

Aesthetics is the study or theory of beauty and the psychological responses to it. Aesthetic resources include natural and man-made landscapes and the way the two are integrated. In this evaluation, aesthetic resources are considered to be primarily visual and relate the structures and the visual attributes of the decommissioning site.

4.3.15.1 Regulations

There are no regulations that relate specifically to the degree to which aesthetics may be impacted by a Federal project. The Bureau of Land Management (BLM), however, has developed a Visual Resource Management (VRM) system,[(a)] which involves cataloging scenic values, establishing management objectives for those values through the resource-management planning process, and evaluating proposed activities to determine whether they conform with the management objectives. This system provides tools for identifying the visual resources of an area and assigning them to inventory classes. It also provides tools for determining whether the potential visual impacts from proposed activities or developments meet the management objectives established for an area or whether design adjustments will be required. This tool was designed to meet the BLM's responsibilities for maintaining scenic values of public lands. However, it does not directly apply to a decommissioning facility, where the landscape has already been altered by the facility's structure.

(a) VRM System (http://www.blm.gov/nstc/VRM/vrmsys.html), accessed July 7, 2001.

4.3.15.2 Potential Impacts of Decommissioning Activities on Aesthetics

Table E-3 in Appendix E indicates that structure dismantlement and entombment are activities that may have aesthetic impacts. Nuclear power facilities generally contain four main buildings or structures, as described in Chapter 3: the containment or reactor building, the turbine building, auxiliary building, and cooling towers (if any). Cooling towers and stacks may be clearly visible from a distance. Sites also contain a number of storage tanks, a large switchyard, and various administrative and security buildings. Decommissioning may include demolition or dismantlement of any of these structures. The switchyard may be left in place after the termination of the license because it is an integral part of the power distribution grid.

Levels of impacts for aesthetic resources are defined largely by the impact of the proposed changes as perceived by the public, not merely the magnitude of the changes themselves. The potential for significance arises with the introduction (or continued presence) of an intrusion into an environmental context, resulting in measurable changes to the community (e.g., population declines, property value losses, increased political activism, tourism losses).

Decommissioning activities and the changes that they bring are considered to have a nondetectable impact on the host communities' aesthetic resources if there are (1) no complaints from the affected public about a changed sense of place or a diminution in the enjoyment of the physical environment and (2) no measurable impact on socioeconomic institutions and processes. They are considered to have detectable but not destablizing impacts on the host communities' aesthetic resources if there are (1) some complaints from the affected public about a changed sense of place or a diminution in the enjoyment of the physical environment and (2) measurable impacts that do not alter the continued functioning of socioeconomic institutions and processes. The activities are considered to have detectable and destabilizing impacts on the host community's aesthetic resources if there are (1) continuing and widely shared opposition to the activities or the changes the activities bring based solely on a perceived degradation of the area's sense of place or a diminution in the enjoyment of the physical environment and (2) measurable social impacts that perturb the continued functioning of community institutions and processes.

4.3.15.3 Evaluation

The aesthetic impacts of decommissioning fall into two sets: (a) impacts, such as noise, associated with decommissioning activities that are temporary and cease when decommissioning is complete and (b) the changed appearance of the site when decommissioning is complete.

Typically, nuclear power facilities are located in flat-to-rolling countryside in wooded or agricultural areas. In some cases, the facility structures are visible for many miles. In other cases, there are only a few views of the facility from the land, although it is more obvious from the water (lake, ocean, or bay).

Aesthetic issues related to construction and operation of facility structures were addressed in many (but not all) of the Final EISs prepared in response to applications for construction permits and operating licenses. In most cases, the visual impacts of the plant were said to have been mitigated to some extent by the surrounding topography or vegetation. In other cases, visible structures (such as cooling towers) were said to be "highly visible" but "the staff does not consider such an impact to be unacceptable." For decommissioning, the issue related to aesthetics is not one of placing another facility or building on a site, but one of removing buildings or structures.

The issues evaluated in this section concern the impacts of decommissioning activities on aesthetic resources at and around all types of nuclear power facilities (PWRs, BWRs, HTGR, or FBR). During the decommissioning period, the appearance of the facility will be slowly altered if the buildings are dismantled.

During decommissioning, the impact of activities on aesthetic resources would be temporary. The impacts would be limited both in terms of land disturbance and the duration of activity and would have characteristics similar to those encountered during industrial construction: dust and mud around the construction site, traffic and noise of trucks, and construction disarray on the site itself. In most cases, these impacts would not easily be visible offsite. Aesthetic impacts could improve fairly rapidly in the case of an immediate DECON if the licensee chooses to dismantle the facility, remove the structures, and regrade and revegetate the site before license termination. Impacts could also remain the same or similar in the case where the licensee maintains the structures throughout the decommissioning period and leaves them standing even after license termination (either after decontamination of the structures or possibly along with entombment of the reactor building) or throughout a long SAFSTOR period or ENTOMB. In these latter cases, the aesthetic impacts of the plant would be similar to those that occurred during the operational period.

The removal of structures is generally considered beneficial to the aesthetic impacts of the site. In a few cases, where facilities have been located on the Great Lakes or ocean coast, the facility may have been used by boaters as a landmark. However, it is highly unlikely that this would become an issue that would preclude dismantlement of the facility structures.

The retention of the structures during a SAFSTOR period or the retention of structures onsite at the time the license is terminated is likewise not an increased visual impact, but instead a continuation of the visual impact analyzed in the facility construction or operations FES. The staff has not identified any mechanism that would result in a greater negative aesthetic impact than had previously been considered during the development of the construction FES.

Decommissioning activities will be conducted onsite, both inside and outside existing buildings (in the case of dismantlement or shipping activities). Any visual intrusion (such as the

dismantlement of buildings or structures) would be temporary and would serve to reduce the aesthetic impact of the site. At a minimum, the aesthetic impact of the site would not be improved but would remain that of an industrial site as evaluated in the facility's original FES.

Licensees are expected to use best-management practices (BMPs) to control many of the potentially adverse impacts of decommissioning activities on aesthetics (e.g., dust and noise), as discussed in other sections.

4.3.15.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential impacts of decommissioning activities and the changes in plant appearance on aesthetics. This information indicates that the impacts on aesthetics are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential impacts on aesthetics are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.16 Noise

Noise is a "direct effect," as defined by Section 1508 of the CEQ Regulations for Implementing NEPA, i.e., effects caused by an action that occur at the same time and place as that action. For NRC licensees, the implementing regulations for NEPA are given in 10 CFR Part 51.

Noise is usually defined as sound that is undesirable because it interferes with speech, communication, or hearing; is intense enough to damage hearing, or is otherwise annoying. Noise levels often change with time. To compare levels over different time periods, several descriptors were developed that take into account this time-varying nature. These descriptors are used to assess and correlate the various effects of noise, including land-use compatibility, sleep and speech interference, annoyance, hearing loss, and startle effects:

- A-weighted sound levels (dBA) - typically used to account for the response of the human ear
- C-weighted scale (dBC) - generally used to measure impulsive noise such as air blasts from explosions, sonic booms, and gunfire
- day-night average sound level (DNL) - used to evaluate the total community noise environment. The DNL is the average A-weighted sound level during a 24-hour period with 10 dB added to nighttime levels (between 10 p.m. and 7 a.m) to account for the increased human sensitivity to night-time noise events.

The discussions in this section relate to noise and related impacts that may be heard offsite. The impacts from noise to workers is addressed in Section 4.3.10.

4.3.16.1 Regulations

The EPA was given the jurisdiction in the Noise Control Act of 1972 (42 USC 4901 et seq.) to promulgate and enforce the regulations that were issued under the Act. Funding for EPA to perform this function was eliminated in early 1981. However, Congress did not repeal the Noise Control Act. The DNL was endorsed by the EPA and is mandated by the U.S. Department of Housing and Urban Development (HUD), the Federal Aviation Administration (FAA), and the Department of Defense (DoD) for land-use assessments. The EPA has determined that no significant effects on public health and welfare occur for the most sensitive portion of the population (within an adequate margin of safety) if the prevailing DNL is less than 55 dB (NAS 1977). The FAA bases its noise guidelines on land use. For residential uses, sound levels up to 65 dB are acceptable. Certain residential areas with sound-blocking features can handle up to 75 dB. For livestock farming and breeding, compatibility is considered to exist up to 75 dBA. These guidelines are advisory in nature and are not mandatory (14 CFR Part 150).

The Federal Housing Administration (FHA), under HUD, established noise assessment guidelines under 24 CFR 51B (1979; amended April 25, 1996). The FHA/HUD site acceptability levels are summarized as follows:

- Acceptable (DNL is 65 dBA or less) - Typical building materials and construction will make any impacts to indoor noise minimal. Outdoor recreation and activities would not be impacted. No approval requirements or abatement measures are needed under this condition.

- Normally unacceptable (DNL is 65 to 75 dBA) - Noise exposure will impact outdoor use of the area and indoor use may be affected. Walls or other barriers may be needed to reduce outdoor noise levels. Indoor noise levels may need to be reduced using special construction methods.

- Unacceptable (DNL above 75 dBA) - The noise conditions in this situation are unacceptable and activities need to be approved on a case-by-case basis.

Local and State regulations may also exist regarding noise restrictions and abatement decisions. Many States prohibit only nuisance noise and have not established specific numerical environmental noise standards, while others have very specific requirements. For example, the State of Maine has sound-level limitations for construction that are a function of time of day, area characteristics, and duration of the noise.

4.3.16.2 Potential Impacts from Noise of Decommissioning Activities

Table E-3 in Appendix E indicates that structure dismantlement is an activity that may have noise impacts. During the decommissioning process, the sounds that might be heard at offsite locations include noise from construction, vehicles, grinders, saws, pneumatic drills, compressors, and loudspeakers. Noise levels from these sources have to be compared to current noise levels of the operating facility and background noise present at the site to determine potential impacts. Table 4-5 lists predicted noise ranges for significant sources of noise during decommissioning.

Noise level increases larger than 10 dBA to the DNL at the site boundary during the day might be expected to lead to interference with outdoor speech communication, particularly in rural areas or low-population areas where the day-night background noise level is in the range of 45 to 55 dBA.

The noise impacts of decommissioning activities are considered detectable if sound levels are sufficiently high to disrupt normal human activities on a regular basis. The noise impacts of decommissioning activities are considered destabilizing if sound levels are sufficiently high that the affected area is essentially unsuitable for normal human activities, or if the behavior or breeding of a threatened or endangered species is affected.

Table 4-5. Predicted Noise Ranges from Significant Decontamination and Dismantlement Sources (INEEL 1999)

			Predicted Noise Level Ranges (dBA) at Various Distances from the Reference Distance			
Source	**Source Strength dBA**	**Reference Distance, m**	**150 m (500 ft)**	**300 m (1000 ft)**	**0.8 km (0.5 mi)**	**1.6 km (1 mi)**
Construction Equipment	85-90	15[(a)]	65-75	59-69	51-61	45-55
Truck	85-90	15	65-75	59-69	51-61	45-55
Rail Engine	86-96	30[(b)]	76-86	71-81	64-74	58-68
Rail Car, 64 km/h (40 mph)	80-86	30	68-74	62-68	53-59	48-54

(a) 15 m ≈ 50 ft.
(b) 30 m ≈ 100 ft.

4.3.16.3 Evaluation

When noise levels are below those that result in hearing loss, impacts are judged primarily in terms of adverse public reactions to the noise. Generally, surveys around major sources of noise such as large highways and airports find that, when the DNL increases above 60 to 65 dBA, noise complaints increase significantly (FICN 1992). FHA/HUD uses a DNL of 65 dBA as the primary criterion for impact on residential properties and nearby populations. The staff believes that noise levels below 60 to 65 dBA are considered to be insignificant. Business and institutional properties may be less sensitive to changes in noise levels, but all populations of concern should be considered when estimating the noise impact of decommissioning activities.

Typically, operating reactor facilities do not result in offsite sound levels greater than 10 dBA above background. However, at some sites, sound levels at and above this level have been calculated at critical receptor locations. The principal sources of noise from facility operations are natural-draft and mechanical-draft cooling towers, transformers, and loudspeakers. Other occasional noise sources may include auxiliary equipment, such as pumps to supply cooling water from a remote reservoir. Generally, noise from these sources is not heard by a large number of people offsite. Of these sources, only loudspeakers would be anticipated to continue during the decommissioning period. The staff assumes that decommissioning activities will be scheduled to minimize high noise levels during the night and during critical periods for important animal species.

In most cases, during decommissioning the sources of noise would be sufficiently distant from critical receptors outside the plant boundaries that the noise would be attenuated to nearly ambient levels and would be scarcely noticeable, as in the case for operating plants. However, in some cases, such as the use of equipment to demolish concrete, the noise levels offsite could be sufficiently loud (60 to 65 dBA at the nearest receptor site) that activities may need to be curtailed during early morning and evening hours. It is highly unlikely, based on past decommissioning experience, that the offsite noise level from a plant during decommissioning would be sufficient to cause hearing loss. However, in one case, noises at a facility being decommissioned have been reported at levels of up to 107 dB (dropping to 50 dB less than 1.6 km [1 mi] away) as a result of the spent fuel pool cooling system. Nearby residents complained to the plant staff about these noise levels; engineering changes were made in the fans that were causing the noise and the issue was resolved.

The timing of the noise impacts and the duration or intensity will vary depending on the decommissioning option and the procedures that are used. More noise will occur during active dismantlement than during the storage period of SAFSTOR. Some demolition activities could increase noise levels temporarily. In addition to mitigation of noise levels based on engineering design, noise abatement procedures can be considered in decommissioning plans to reduce noise, particularly at night.

No differences are expected between the noise levels of future decommissioning activities at operating plants and the noise levels observed at facilities undergoing decommissioning. It is anticipated that most decommissioning activities will not represent an audible intrusion on the community for any type of nuclear power facility (BWR, PWR, HGTR, or FBR).

4.3.16.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential noise impacts of decommissioning activities. This information indicates that the noise impacts are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all facilities, the potential noise impacts are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.17 Transportation

In considering activities for decommissioning, transportation can be considered both an activity and an issue. Transportation of equipment, material, and waste is an activity that is performed throughout the entire decommissioning process. However, it is treated as an issue in this Supplement and is given its own section.

This section addresses impacts related to transporting equipment and materials (radiological and nonradiological) offsite. Materials transported to offsite disposal facilities include nonhazardous waste, LLW, hazardous waste, and mixed waste. As discussed in Chapter 1, the shipment of spent nuclear fuel is not within the scope of this Supplement. Radiological impacts include exposure of transport workers and the general public along transportation routes. Nonradiological impacts include additional traffic volume, additional wear and tear on roadways, and potential traffic accidents.

4.3.17.1 Regulations

Regulations that apply to the transportation of hazardous, mixed waste, and radioactive material promulgated by the U.S. Department of Transportation (DOT) are contained in 49 CFR Parts 171-177. NRC regulations related to transportation of LLW are contained in 10 CFR Part 71, "Packaging and transportation of radioactive material." These regulations contain requirements for transport vehicles, maximum radiation levels for packages and vehicles, special packaging requirements, driver training, vehicle and packaging inspections, marking and labeling of packages, placarding of vehicles, and training of emergency personnel to respond to mishaps. Highway routing restrictions for certain shipments of LLW are also included in DOT regulations. NRC regulations contain performance requirements for certain

types of transportation packages of radioactive material. In addition, Federal and State regulations govern the size and weights of trucks. The staff assumes that equipment, materials, and waste transportation are conducted within applicable regulations.

4.3.17.2 Potential Decommissioning Impacts from Transportation

Table E-3 in Appendix E indicates that transportation-related activities may impact the transportation infrastructure and public health and safety. The types of transportation impacts for decommissioning nuclear power facilities and operating plants are similar. The factors that determine the magnitude of transportation impacts of decommissioning include:

- changes in waste production due to decontamination and dismantlement activities that increase the amount of waste shipped offsite
- changes in the transportation methods (rail, truck, or barge) related either to the increased amount to be shipped offsite or to the type of material to be shipped.
- changes in the mix of types of waste categories shipped offsite.

The public health impacts result from exposures of transport workers and the general public along transportation routes during normal shipments and from material released as a result of transportation accidents, as well as from transportation accidents that do not involve the release of radioactive material. The radiological impacts to public health and safety are considered detectable if the dose rates from shipping containers exceed regulatory limits. They are considered destabilizing if material is shipped in unapproved containers. The nonradiological impacts of transportation of radioactive waste are considered detectable or destabilizing if the vehicles are maintained or driven in a manner that would result in a significantly greater accident rate than experienced by the trucking industry.

The nonradiological, infrastructure impacts are increases in traffic density, wear and tear on roadways and railways, and transportation accidents. The impacts of decommissioning activities on the transportation infrastructure are considered detectable if the increased traffic causes a decrease in level of service or measurable deterioration of affected roads that can be directly tied to activities at the plant. The impacts of decommissioning activities are considered destabilizing if the level of service becomes unacceptable or roads become unusable because of activities at the plant.

4.3.17.3 Evaluation

The transportation impacts are dependent on the number of shipments to and from the facility, the type of shipments, the distance that material is shipped, and the nonradiological waste/fixed waste quantities and disposal plans. The distance that the waste travels depends on the plant's proximity to a disposal site. One decommissioning facility, located in Oregon, ships LLW 480

km (300 mi) to the U.S. Ecology burial site on the Hanford Reservation in Richland, Washington. Another decommissioning facility located in California ships LLW 4300 km (2700 mi) to the Barnwell facility in South Carolina.

The number of shipments and volume of waste shipped during the decontamination and dismantlement phases of decommissioning are greater than during operations. Information on shipments, which was received from nine plants, is shown in Appendix K. Because data on the waste volume of shipments were received from only seven plants, estimates of waste volume and shipment numbers in several cases (as footnoted in the table) reflect only a single facility and may be significantly higher or lower than for the average facility in that grouping. The impacts from FBRs and HTGRs would be encompassed by those for the PWRs and BWRs since the distance shipped is less and the plant sizes are generally smaller.

Nonradioactive material from the site for general disposal will likely be shipped to landfills. However, because licensees cannot release material with detectable amounts of radioactive material, a number of sites may ship much of their solid waste to vendors specializing in the management of LLW or to LLW sites such as that at Clive, Utah.

A generic analysis was conducted to estimate human health impacts associated with transporting decontamination and dismantlement wastes from reactor sites to LLW burial grounds. The RADTRAN 4 computer code (Neushauser and Kanipe 1992), which is commonly used for transportation impact calculations in support of environmental documentation, was used for the analysis. RADTRAN 5 (Neushauser and Kanipe 1996) is the latest version of the code, originally developed by Sandia National Laboratories to support the NUREG-0170 environmental impact analysis (NRC 1977). It uses the same basic methods for calculating impacts but does the calculations in a probabilistic framework.

Based on information from Trojan and Maine Yankee, LLW was categorized as one of three types--high activity, low activity, and very low activity--and a typical volume and activity were estimated for each type of LLW. The impacts of transporting each type of LLW were estimated. There are likely to be additional nonradiological impacts on public health and safety from transportation accidents associated with transportation of uncontaminated material.

Radiological impacts: For this Supplement, the public health and safety impacts of transportation of radioactive waste are evaluated on the basis of compliance with applicable regulations. The Commission has taken the position (46 FR 21619) that its "...regulations are adequate to protect the public against unreasonable risk from the transportation of radioactive materials." This evaluation was based, in part, on the findings of NUREG-0170 (NRC 1977). A recent re-evaluation of transportation risks, using updated information and assessment tools (Sprung et al. 2000), found that risks are lower than estimated in NUREG-0170. Licensees are expected to comply with all applicable regulations when shipping radioactive waste from decommissioning. Therefore, the effects of transportation of radioactive waste on public health and safety are considered to be neither detectable nor destabilizing.

Nevertheless, the staff performed an evaluation of the likely magnitude of these impacts using available data. Radiological impacts are divided into those for "routine" or incident-free shipments (i.e., the shipment reaches its destination without incident) and those for shipments that involve an accident with a subsequent radiological release. In each case, the impact is expressed in cumulative dose for the transport workers and public. The results of the calculations are shown in Table 4-6. The details of the assumptions made in the analysis are discussed in Appendix K. In order to bound the impacts, a distance of 4800 km (3000 mi) was selected. Dose rates for incident-free shipment of high-activity LLW were assumed to be at the regulatory limits, and dose rates for incident-free shipment of low-activity LLW were assumed to be at one-tenth of regulatory limits. Radiological impacts of shipment of very low-level activity LLW were assumed to be negligible compared to shipments of high-level and low-level activity LLW. However, shipment of very low-level activity waste was considered in evaluating nonradiological transportation of LLW. With these assumptions and the additional assumptions listed in Appendix K, the results of the analysis should bound the transportation impacts for all decommissioning options for PWRs and BWRs.

Ramsdell et al. (2001) indicate that shipment of spent fuel by rail reduces the radiological impacts significantly (more than a factor of 10 for shipments from the northeast to Nevada). Similar reductions would be expected in the radiological impacts of the shipment of LLW from decommissioning if shipments were made by rail rather than by truck. Barge shipments of the high-activity waste could reduce the radiological impacts even further.

Nonradiological impacts: Nonradiological impacts of transportation of LLW include increased traffic and wear and tear on roadways. Decommissioning experience has been that the number of LLW shipments from a site averages much less than 1 per day. This number of shipments per day is not nearly large enough to have a detectable or destabilizing effect on traffic flow or road wear.

Nonradiological impacts of transportation accidents are typically expressed in terms of fatalities. RADTRAN estimates fatalities caused by traffic accidents using the distance traveled and average fatality rates per unit distance. Traffic accidents are not related to radioactivity; therefore, the impacts of transportation accidents should be based on the round-trip distance between the decommissioning site and the waste facility. For consistency, a 9600-km (6000-mi) round-trip distance is assumed for the fatality estimates shown in Table 4-6. Again, these numbers reflect the entire decommissioning period. The fatality estimates would be the same for shipments of any other commodity.

The following values may provide some perspective for evaluating the values in Table 4-6. A recent publication (Saricks and Tompkins 1999) gives average accident rates on interstate highways. The average accident rates for trucks are 3.15×10^{-7}, 3.66×10^{-7} and 6.54×10^{-7} per kilometer (5.07×10^{-7}, 5.89×10^{-7}, and 1.05×10^{-6} per mile) for highways in rural, suburban, and urban areas, respectively. The national average fatality rate for trucks is 5.5×10^{-9} fatalities per

Table 4-6. Impacts of Transportation of LLW from Decommissioning

	High-Activity Waste	Low-Activity Waste	Very Low-Activity Waste	Total
Number of Shipments during Decommissioning	227	84	360	671[a]
Incident-Free Transportation Impacts – Cumulative Dose, person-Sv (person-rem)				
Crew	0.496 (49 6)	0.184 (18.4)	--	0.680 (68 0)
Public along route	0.129 (12 9)	0 020 (2 00)	--	0.149 (14 9)
Onlookers	0.123 (12 3)	0 019 (1.90)	--	0.142 (14.2)
Total	0.748 (74.8)	0 223 (22.3)	--	0 971 (97.1)
Incident-Free Transportation Impacts – Latent Cancer Fatalities (LCF)				
Crew[b]	0 0198	0.00736	--	0.0272
Public along route[c]	0 0065	0 00100	--	0 00744
Onlookers[c]	0 0062	0 00096	--	0.00711
Total	0.0324	0 00931	--	0.0417
Accident Impacts				
Cumulative Dose, person-Sv (person-rem)	5.39×10^{5} (5.39×10^{-3})	1.28×10^{-4} ($1\ 28\times10^{-2}$)	--	1.82×10^{-4} (1.82×10^{2})
Nonradiological Fatalities	0 0120[d]	0 00465[d]	0.019[d]	0.0356[d,e]
Total				
Cumulative Dose, person-Sv (person-rem)	0.748 (74.8)	0 223 (22.3)	--	0 971 (97.1)
Fatalities	0 0419	0.0136	0 0190	0 0745[e]

(a) The total number of shipments during decommissioning may be significantly increased if State or local government agencies require removal of all structures and concrete from the site. However, the additional shipments would be uncontaminated material.
(b) Assuming 4.0×10^{-2} LCF/person-Sv (4.0×10^{-4} LCF/person-rem) for crew.
(c) Assuming 5.0×10^{2} LCF/person-Sv (5.0×10^{-4} LCF/person-rem) for general public.
(d) Based on fatal accident rate of 5.5×10^{9} per km (8.8×10^{9} per mi).
(e) The number of fatalities will increase if there are additional shipments of uncontaminated material in proportion to the number of miles driven.

kilometer (8.8×10^{-9} fatalities per mile). Historically, the accident rate for activities at nuclear facilities has been lower than the national average for similar activities because of the industry emphasis on training and adherence to established procedures.

It is not likely that the actual nonradiological impacts of transportation accidents would be as high as indicated or that they would be either detectable or destabilizing.

The number of shipments into the decommissioning facility would be much smaller than the number of shipments from the facility. The concrete used to entomb a plant would be manufactured at a batch plant onsite, or the licensee would use local sources for the materials needed for entombing a facility. Shipments of materials into the facility during decommissioning or following the preparation for entombment of the facility would be minimal. It is anticipated that many of the shipments to the facility undergoing decommissioning, including shipments of equipment and heavy machinery, would come from local sources and, thus, the distance traveled would be minimal. Therefore, the staff concludes that transporting the materials to the site would not significantly impact the overall traffic volume or compromise the safety of the public.

Previous or anticipated decommissioning activities at the FBR or HTGR have not and are not expected to result in impacts on transportation that are different from those found at other nuclear facilities.

4.3.17.4 Conclusions

The staff has considered available information, including comments received on the draft of Supplement 1 of NUREG-0586, on the potential transportation impacts of decommissioning activities. This information indicates that the transportation impacts are not detectable or destabilizing. Therefore, the staff makes a generic conclusion that for all plants, the potential transportation impacts are SMALL. The staff has considered mitigation measures and concludes that no additional mitigation measures are likely to be sufficiently beneficial to be warranted.

4.3.18 Irreversible and Irretrievable Commitment of Resources

Irreversible commitments are commitments of resources that cannot be recovered, and irretrievable commitments of resources are those that are lost only for a period of time. The irreversible and irretrievable commitments of resources that are anticipated during the decommissioning process are similar to those that were considered in the FESs for facility construction permits and operating licenses. The FESs for plant operation cite uranium as the principal natural resource irretrievably consumed in facility operation. However, following permanent cessation of operations, uranium is no longer consumed. As discussed in Chapter 1, disposal of uranium as part of spent nuclear fuel is not within the scope of this Supplement. Other resources considered in some FESs include land, water, human resources, cultural, and threatened and endangered species.

4.3.18.1 Regulations

CEQ regulations at 40 CFR 1502.13 and NRC regulations at 10 CFR 51, Appendix A to Subpart A, state that an environmental impact statement include a discussion of any irreversible or irretrievable commitments of resources. In addition, there are regulations that deal with the use of land (addressed in Section 4.3.1, "Onsite/Offsite Land Use"), water use and quality (Sections 4.3.2 and 4.3.3), and air quality (Section 4.3.4). Disposal of uranium is not within the

scope of this document. Land devoted to LLW disposal sites or in industrial landfills is also not within the scope of this document and is addressed in the licensing documents for the disposal site.

4.3.18.2 Potential Impacts of Decommissioning Activities on Irretrievable Resources

Table E-3 in Appendix E indicates that decommissioning activities with the potential to impact irreversible and irretrievable commitment of resources include structural dismantlement; LLW packaging, storage, and disposal; and transportation.

An irreversible commitment of resources is defined as a loss that is detectable and destabilizing, such as when a species becomes extinct, or, in the case of mining, when ore is removed. Irretrievable commitments can be considered as a tradeoff. If a transportation corridor is constructed, the land uses are not available for as long as the corridor remains. The destabilizing impacts are those that adversely impact the resources discussed in this Supplement (Sections 4.3.1 through 4.3.17).

4.3.18.3 Evaluation

Although most FESs addressed primarily uranium fuel, other resources were discussed in some of the FESs. This included land used for plant buildings, components such as large underground concrete foundations, and certain other equipment considered irretrievable due to practical aspects of reclamation and/or radioactive decontamination. The use of the environment (air, water, and land) by the facilities was not deemed to represent significant irreversible or irretrievable resource commitments but rather a relatively short-term investment.

Whether land is considered to be an irretrievable resource depends largely on the decisions at the time of license termination. If the license is terminated for unrestricted use, then the land will be available for other uses, whether or not the decommissioning process returned the land to a "Greenfield" site or to an industrial complex. If ENTOMB1 is selected, license termination could still allow unrestricted access after 30 to 60 years. However, if the ENTOMB2 option is selected, the land under the facility will not be available for alternative uses and would be considered irretrievable.

The only other irretrievable resources that would occur during the decommissioning process would be materials used to decontaminate the facility (e.g., rags, solvents, gases, and tools), and fuel used for construction machinery and for transportation of materials to and from the site. However, these resources are minor.

Although the use of land, water, air, and fuel oil during decommissioning is minimal or nonexistent, the disposal of radioactive waste and nonradioactive waste would be considerable for some options, such as DECON to a "Greenfield" (nonindustrial) site. Even though the disposal of radioactive waste is outside the scope of this document, the volume of land required for radioactive waste disposal is estimated in Table 4-7 for the SAFSTOR and DECON options, based on data obtained from six plants. The quantities of waste shown in Table 4-7 for the two

ENTOMB options were estimated based on the scenarios described in Chapter 3. The greatest estimated volume of radwaste is from a facility that is being decommissioned to "Greenfield" (no structures remaining onsite). It is located in a State that does not allow disposal of the industrial waste within an in-state industrial waste site.

Table 4-7. Volumes of Land Required for LLW Disposal[(a)]

Decommissioning Option	Reactor Type	Volume of Land Required for LLW Disposal, m^3 (ft^3)	Plant Size (Electrical Capacity, MWe)
DECON	PWR	8000 - 10,000 (282,500 - 353,000)	1130 to 1825
	BWR	2000 (71,000)	240
SAFSTOR	PWR	600 - 45,000 (21,000 -1.5 million)	23 to 1437
	BWR	18,000 (636,000)	660
ENTOMB1	Either	<5000 (<177,000)	Variable
ENTOMB2	Either	<500 (<17,700)	Variable

(a) Data were available from a limited number of facilities and based on actual estimates provided by the licensees.

4.3.18.4 Conclusions

The staff has considered available information on the potential impacts of decommissioning on irreversible and irretrievable commitments of resources, including comments received on the draft of Supplement 1 of NUREG-0586. This information indicates that the impacts of decommissioning on irreversible and irretrievable commitments are neither detectable nor destabilizing. Therefore, the staff makes the generic conclusion that the impacts on irreversible and irretrievable commitments are SMALL. The staff has considered mitigation and concludes that no additional measures are likely to be sufficiently beneficial to be warranted.

4.4 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and utilization facilities."

10 CFR 51. Code of Federal Regulations. Title 10, Energy, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and

transportation of radioactive material."

10 CFR 100. Code of Federal Regulations, Title 10, *Energy*, Part 100, "Reactor site criteria."

14 CFR 150. Code of Federal Regulations, Title 14, *Aeronautic and Space*, Part 150, "Airport noise compatibility planning."

24 CFR 51B. Code of Federal Regulations, Title 24, *Housing and Urban Development*, Part 51B, "Environmental criteria and standards."

29 CFR 1902. Code of Federal Regulations, Title 29, *Labor*, Part 1902, "State plans for the development and enforcement of State standards."

29 CFR 1910. Code of Federal Regulations, Title 29, *Labor*, Part 1910, "Occupational safety and health standards."

29 CFR 1926. Code of Federal Regulations, Title 29, *Labor*, Part 1926, "Safety and health regulations for construction."

29 CFR 1952. Code of Federal Regulations, Title 29, *Labor*, Part 1952, "Approved State plans for enforcement of State standards."

36 CFR 800. Code of Federal Regulations, Title 36, *Parks, Forests, and Public Property*, Part 800, "Protection of historic properties."

40 CFR 50. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 50, "National primary and secondary ambient air quality standards."

40 CFR 51. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 51, "Requirements for preparation, adoption, and submittal of implementation plans."

40 CFR 61. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 61, "National emission standards for hazardous air pollutants; regulation of radionuclides."

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40 CFR 1508. Code of Federal Regulations, Title 40, *Protection of Environment*, Part 1508, "Terminology and index."

49 CFR 171 - 177. Code of Federal Regulations, Title 49, *Transportation*, Parts 171-177, "General information, regulations, and definitions"; "Hazardous materials table, special provisions, hazardous materials, communications, emergency response information, and training requirements"; "Shippers--general requirements for shipments and packagings"; "Carriage by rail"; "Carriage by aircraft"; "Carriage by vessel"; "Carriage by public highway."

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Fish and Wildlife Coordination Act, 16 USC 661 et seq.

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4.5 Related Documents

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Haddam Neck Plant (HNP). 2000. "Haddam Neck Plant License Termination Plan," Rev. 0.

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http://nepa.eh.doe.gov/eis/eis0290/Ch_5/5_10/5_10Noise.html.

5.0 No-Action Decommissioning Alternative

The action discussed in this Supplement and in the *Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (1988 GEIS; NRC 1988) is decommissioning. The only alternative to the action of decommissioning is not to decommission the facility. The option to restart the reactor is not considered to be an alternative to decommissioning because the regulations do not allow the licensee to reload fuel and restart the facility after submitting a certification that the fuel has been removed from the reactor vessel.

The alternative to decommissioning at the end of the licensing period is a "no action" alternative, implying that a licensee would simply abandon or leave a facility after ceasing operations. Once the facility permanently ceases operation, if the licensee does not conduct decommissioning activities to an extent that meets the license termination criteria in 10 CFR 20 Subpart E, then the license will not be terminated (although the licensee will not be authorized to operate the reactor). The licensee will be required to comply with the necessary requirements for the operating license. As a result, the environmental impacts for maintaining the nuclear reactor facility will be considered to be in the bounds of the appropriate, previously issued Environmental Impact Statements.

The objective of decommissioning is to restore a radiologically contaminated facility to a condition such that there is no unreasonable risk from the decommissioned facility to the public health and safety. The U.S. Nuclear Regulatory Commission (NRC) regulations do not allow the option of not decommissioning. Under NRC regulations, the original operating license for a nuclear power plant is issued for up to 40 years. The license may be renewed for additional 20-year periods if NRC requirements are met. However, at the end of the term of the license (whether it has been extended or not), the regulations require that the facility be decommissioned.

5.1 Reference

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities.* NUREG-0586, NRC, Washington, D.C.

6.0 Summary of Findings and Conclusions

6.1 Summary of Findings

This chapter summarizes the findings and conclusions from the evaluation of environmental impacts related to decommissioning of permanently shutdown commercial nuclear power reactors. Table 6-1 presents each environmental issue that was evaluated and identifies whether the issue is considered generic or site-specific. Of the environmental issues assessed (see Table 6-1), most of the impacts are generic and SMALL for all plants regardless of the decommissioning activity and identified variables (see Appendix E for a list of the variables).

Two issues were identified that require a site-specific analysis: threatened and endangered species and environmental justice.

In accordance with the Endangered Species Act of 1973 (16 USC 1531 et seq.), the appropriate Federal agency (either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service) must be consulted about the presence of threatened or endangered species. Informal consultation will be initiated by the U.S. Nuclear Regulatory Commission (NRC) staff with the appropriate service after the licensee announces permanent cessation of operations. It is expected that any formal or informal consultation will be completed prior to the licensee beginning major decommissioning activities, which can occur 90 days after the submission of the post-shutdown decommissioning activities report (PSDAR). At that time, it will be determined whether such species could be affected by decommissioning activities and whether formal consultation will be required to address the impacts. Each State should also be consulted about its own procedure for considering impacts to State-listed species.

Executive Order 12898 (59 FR 7629), dated February 16, 1994, directs Federal executive agencies to consider environmental justice under the National Environmental Policy Act of 1969 (NEPA). Although the NRC is an independent agency, the Commission has committed to undertake environmental justice reviews. Subsequent to the submittal of the PSDAR, the NRC staff will consider the impacts related to environmental justice from decommissioning activities.

Four issues were determined to be, depending on the circumstances, either generic or site-specific: land use, aquatic ecology, terrestrial ecology, and cultural and historic resources. Impacts resulting from onsite land use, impacts to aquatic and terrestrial resources resulting from activities occurring within the facility's operational areas, and impacts to cultural or historic resources resulting from activities within the facility operational area were determined to be generic and SMALL.

Table 6-1. Summary of the Environmental Impacts from Decommissioning Nuclear Power Facilities

Issue	Generic	Impact
Onsite/Offsite Land Use		
- Onsite land use activities	Yes	SMALL
- Offsite land use activities	No	Site-specific
Water Use	Yes	SMALL
Water Quality		
- Surface water	Yes	SMALL
- Groundwater	Yes	SMALL
Air Quality	Yes	SMALL
Aquatic Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Terrestrial Ecology		
- Activities within the operational area	Yes	SMALL
- Activities beyond the operational area	No	Site-specific
Threatened and Endangered Species	No	Site-specific
Radiological		
- Activities resulting in occupational dose to workers	Yes	SMALL
- Activities resulting in dose to the public	Yes	SMALL
Radiological Accidents	Yes	SMALL
Occupational Issues	Yes	SMALL
Cost	NA[(a)]	NA
Socioeconomic	Yes	SMALL
Environmental Justice	No	Site-specific
Cultural and Historic Resource Impacts		
- Activities within the operational areas	Yes	SMALL
- Activities beyond the operational areas	No	Site-specific
Aesthetics	Yes	SMALL
Noise	Yes	SMALL
Transportation	Yes	SMALL
Irretrievable Resources	Yes	SMALL

(a) A decommissioning cost assessment is not a specific National Environmental Policy Act (NEPA) requirement. However, an accurate decommissioning cost estimate is necessary for a safe and timely plant decommissioning. Therefore, this Supplement includes a decommissioning cost evaluation, but the cost is not evaluated using the environmental significance levels nor identified as a generic or site-specific issue.

Impacts resulting from offsite land use to support decommissioning activities, impacts to aquatic and terrestrial resources resulting from activities occurring outside the facility's operational areas, and impacts to cultural, historic or archeological resources resulting from activities beyond the operational areas cannot be evaluated generically and would require a site-specific analysis before undertaking the activity. These are termed conditionally site-specific.

Before a licensee conducts any decommissioning activity that might result in the disturbance of historic properties or archeological resources outside the site operational area, the NRC will, in accordance with the National Historic Preservation Act of 1966, as amended (16 USC 470 et seq.), consult with the appropriate State (or Tribal) Historic Preservation Officer to evaluate potential impacts.

The issue of cost was addressed in this Supplement but was not evaluated.

The staff also determined that the issue of long-term radiological aspects of Rubblization or onsite disposal of slightly contaminated material could not be evaluated generically and would require a site-specific analysis. The site-specific analysis would be conducted at the time the license termination plan (LTP) for the site is submitted.

For the 19 reactors listed in Table F-1 that have permanently ceased operation during the period 1963 through 1997, the staff has determined that no issue or activity must be re-evaluated immediately, provided that the licensee does not change the decommissioning option previously chosen. The NRC staff conducted a detailed environmental review on a number of these facilities prior to 1996 as part of the decommissioning plan review. Licensees for several of these reactors have submitted LTPs for NRC review and approval, and the staff has evaluated or is evaluating site-specific environmental impacts as part of that review. Therefore, for many of the 19 facilities, a site-specific assessment has been performed. Because decommissioning is substantially underway at all 19 reactors, the impacts for the issue of environmental justice have already occurred and an evaluation at the present time would provide little value and opportunity for mitigation. Impacts on threatened and endangered species are considered on an ongoing basis and the issuance of this Supplement would not accelerate a review of the issue solely because the issue is one that cannot be evaluated generically. The staff will continue to conduct site-specific consultations with the appropriate resource agency, as the need arises.

Therefore, the NRC has determined that it is not necessary at this time to conduct an evaluation of the environmental justice or impacts on threatened and endangered species at the 19 permanently shutdown reactors listed in Table F-1. However, should a licensee choose a different decommissioning option from its current choice (e.g., SAFSTOR rather than DECON),

then the site-specific issues would need to be considered prior to undertaking a decommissioning activity not previously evaluated.

For the 19 facilities listed in Table F-1 that have initiated decommissioning, as well as for any facilities that permanently cease operation in the future, any planned decommissioning activity would require a site-specific analysis prior to undertaking the proposed activity (see Section 1.5) if the activity:

- results in an impact outside the range of impacts postulated by this Supplement or
- raises environmental issues that were not considered in this Supplement or
- involves an issue determined to be site specific or conditionally site-specific as described above in this Supplement or
- involves a combination of the above.

6.2 Conclusions

A licensee undergoing or planning decommissioning of a nuclear reactor facility may use this Supplement in its evaluation of the environmental consequences from decommissioning activities. The impacts identified in this Supplement are designed to span the range of impacts for all commercial power reactor facilities that have permanently shut down as well as for the reactor facilities that are currently operating, including the facilities that have, or may, renew their operating license beyond the original 40-year license.

For those issues that have been determined to be generic, licensees may proceed with the decommissioning activity without further analysis provided that the impacts resulting from those activities fall within the range of impacts as described in Chapter 4. However, if the impacts of an activity fall outside the range predicted in Chapter 4, or if the activity results in impacts to environmental issues not considered in this Supplement, or if the impact involves an environmental issue determined to be conditionally site-specific as defined above, then the activity cannot be performed until a further site-specific analysis is completed along with a license-amendment request and NRC has approved the license amendment (the license-amendment request will provide an opportunity for a public hearing).

6.3 References

Endangered Species Act of 1973, as amended, 16 USC 1531 et seq.

Executive Order 12898. 1994. "Environmental Effects of Federal Programs on Minority and Low-Income Populations." 59 FR 7629, February 16, 1994.

National Environmental Policy Act (NEPA) of 1969, as amended, 42 USC 4321 et seq.

National Historic Preservation of 1966, as amended, 16 USC 470 et seq.

Appendix A

Appendixes A and B have been moved and redesignated as Appendixes N and O. All comments and responses, whether written or oral, are now contained in Appendixes N, O, and P, which comprise Volume 2 of this Supplement.

Appendix B

Appendixes A and B have been moved and redesignated as Appendixes N and O. All comments and responses, whether written or oral, are now contained in Appendixes N, O, and P, which comprise Volume 2 of this Supplement.

Appendix C

Contributors

Appendix C

Contributors

The overall responsibility for the preparation of this Supplement to the Generic Environmental Impact Statement (GEIS) on Decommissioning was assigned to the Office of Nuclear Reactor Regulation (NRR), U.S. Nuclear Regulatory Commission (NRC). This Supplement was prepared by members of the NRR with assistance from other NRC organizations and the Pacific Northwest National Laboratory.

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Appendix C

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James V. Ramsdell, Jr.	Staff Scientist	Air Quality
Melissa Peffers	Research Scientist	Industrial Hygiene
Steve Short	Staff Engineer	Cost
Phil Daling	Staff Engineer	Transportation
Mark C. Bierschbach	Development Engineer	Cost
Dennis Haffner	Senior Research Scientist	Cost
Kathleen Rhoads	Senior Research Scientist II	Radiological
James R. Weber	Technical Comm Specialist	Technical Editor
Barbara Wilson	Technical Comm Specialist	Technical Editor
Jean M. Cheyney	Text Processor	Administrative Support
Rose M. Urbina	Text Processor	Administrative Support
Tara O. Eschbach	Research Scientist	Assistant
Bev Miller	Research Scientist	Assistant
Sue Gulley	Program Administrator	Assistant
Amanda Stegen	Research Scientist	Assistant
Terri Miley	Research Scientist	Assistant

(a) Retired in January 2002.
(b) Nuclear Materials Safety and Safeguards.
(c) Pacific Northwest National Laboratory is operated for the U.S. Department of Energy by Battelle.
(d) Currently with the Office of Nuclear Regulatory Research, NRC.

Appendix D

Further Discussion of Out-of-Scope Activities

Appendix D

Further Discussion of Out-of-Scope Activities

Various activities that are performed during decommissioning may seem intuitively to be part of the decommissioning process. However, they are not considered within the scope of this Supplement because these activities have already received an environmental review during the promulgation of the U.S. Nuclear Regulatory Commission (NRC) regulations governing such activities. They are reviewed and regulated by the NRC under other regulations. These activities include the following:

- Independent Spent Fuel Storage Installation (ISFSI): construction/maintenance/decommissioning: An ISFSI is a facility designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. The ISFSI may be located at the same site as the nuclear power facility or at another location. ISFSIs are used by operating plants that require increased spent fuel storage capacity because their spent fuel pools have reached their capacity and the U.S. Department of Energy (DOE) facility for disposing of spent fuel and high-level nuclear waste is not yet available. Decommissioning facilities may use ISFSIs as an alternative to leaving the fuel in the spent fuel pool while waiting for DOE to take ownership of the spent fuel. Licensees that remove the spent fuel from their pools and place it in an ISFSI can then complete the decommissioning process on the power-generation facilities and subsequently terminate the facility license. In some instances, the license for the nuclear power reactor can be terminated while the ISFSI, which has a separate license and is located on the facility site, would continue to be regulated by the NRC.

  An ISFSI can be operated either under the same license that is used for the operating or decommissioning facility (called a "Part 50 license," referring to 10 CFR Part 50), or under a site-specific license (called a "Part 72 license," referring to 10 CFR Part 72). Regulations for the licensing and operation of an ISFSI, including quality assurance and quality control requirements, are found in 10 CFR Part 72. If a licensee chose to operate the ISFSI under a Part 50 license, they could, by way of a license-amendment request, change the ISFSI to a Part 72 license, thus allowing termination of the Part 50 license at the end of the reactor facility decommissioning process.

The decommissioning of the ISFSI is also handled separately from the decommissioning of the nuclear power facility. The 1988 Generic Environmental Impact Statement (GEIS) (NRC 1988) contained a section on decommissioning of ISFSIs, which is not updated in this Supplement.

- Spent fuel storage and maintenance: The Commission has independently, in a separate proceeding, the "Waste Confidence Proceeding," made a finding that there is:

  > reasonable assurance that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 30 years beyond the licensed life for operation (which may include the term of a revised license) of that reactor at its spent fuel storage basin, or at either onsite or offsite independent spent fuel storage installations. (54 FR 39767)

  The Commission has committed to review this finding at least every 10 years. In its most recent review, the Commission concluded that experience and developments since 1990 were not such that a comprehensive review of the Waste Confidence Decision was necessary at that time (64 FR 68005). Accordingly, the Commission reaffirmed its finding of insignificant environmental impacts cited above. This finding is codified in the Commission's regulations at 10 CFR 51.23(a). The operation of a spent fuel pool or an ISFSI is not uniquely linked to decommissioning. All operating nuclear power facilities have spent fuel pools and some (with the number anticipated to increase) have ISFSIs generally located adjacent or near to the power reactor facility.

- Spent fuel transport and disposal away from the reactor location: The temporary storage or future permanent disposal of spent fuel at a site other than the reactor site is not within the scope of this Supplement. Licensees are prohibited from shipping spent fuel from one reactor's spent fuel pool to another's without NRC approval. Amendment of one or both of the facilities' licenses would be required before fuel transfer.

  Transportation of spent fuel and other high-level nuclear wastes is governed by regulations in 10 CFR Part 71, "Packaging and Transportation of Radioactive Material." Disposal of spent fuel and high-level wastes (HLW) are governed by the Nuclear Waste Policy Act (NWPA) of 1982, as amended, which defined the goals and structure of a program for permanent, deep geologic repositories for the disposal of high-level radioactive waste and non-reprocessed spent fuel. Under this Act, the DOE is responsible for developing permanent disposal capacity for spent fuel and other high-level nuclear wastes. On July 9, 2002, the U.S. Congress approved Yucca Mountain as the first long-term geologic repository for spent nuclear fuel and high-level radioactive waste. A HLW repository will be built and operated by DOE and licensed by the NRC. Title 10 CFR Part 61 contains rules

governing the licensing to receive and possess source, special nuclear, and by-product material at a geological repository operations area that is sited, constructed, or operated in accordance with the NWPA (1982). However, the Commission proposes to supersede the generic criteria in Part 60 for disposal at a waste repository with specific criteria in a new 10 CFR Part 63 issued on February 22, 1999 (64 FR 8640).

- Interim storage of Greater-than-Class-C (GTCC) Waste: The NRC regulations at 10 CFR 61.55 define three classes of low-level waste (LLW) (A, B, and C) that are suitable for near-surface disposal. Class C waste is required to meet the most rigorous disposal requirements. The LLW that exceeds the concentration limits set for Class C waste is referred to as GTCC waste. Typically, GTCC waste is composed of activated metal components and process wastes.

  On October 11, 2001 the NRC amended its regulations (in 66 FR 51823), to permit interim storage of GTCC waste used or generated by commercial power reactors within an ISFSI or monitored retrievable storage (MRS) facility. This change permits the co-locating of spent fuel and solid reactor-related GTCC waste in different casks and containers within the ISFSI or MRS. Commingling of spent fuel and GTCC waste in the same storage cask is not permitted, except on a case-by-case basis. Ultimately, GTCC waste must be disposed of in a geologic repository.

- LLW disposal at a licensed LLW site or treatment of LLW at compactor facilities: The disposal of LLW is not within the scope of this Supplement. LLW is defined as any radioactive waste that is not classified as HLW, spent nuclear fuel, transuranic waste,[a] or uranium or thorium mill tailings. LLW often contains small amounts of radioactivity dispersed in large amounts of material, but may also have activity levels requiring shielding and remote handling. LLW that is generated during decommissioning is usually composed of the following material contaminated with radionuclides: rags, papers, filters, solidified liquids, ion-exchange resins, tools, equipment, discarded protective clothing, dirt, construction rubble, concrete, and piping.

  Regulations related to LLW disposal are in 10 CFR Part 61 and 10 CFR Part 20, Subpart K. A final GEIS supporting the regulations in 10 CFR Part 61, was published in 1982 as "Final Generic Environmental Impact Statement for 10 CFR Part 61," NUREG-0945 (NRC 1982). A license for the LLW disposal site is not issued until the applicant provides an environmental report (ER) indicating that the applicant's proposed disposal site, design,

(a) Transuranic waste contains man-made elements heavier than uranium that decay by emitting alpha particles. Such waste is produced during reactor fuel assembly, weapons fabrication, and chemical processing operations.

operations, site closure, and post-closure institutional controls are adequate to protect public health and safety. The licensee for the LLW site must show that there is reasonable assurance that (1) the general population will be protected from releases of radioactivity, (2) that individual inadvertent intruders are protected, (3) that standards for radiation protection in 10 CFR Part 20 are met, and (4) that the long-term stability of the disposed waste and the disposal site will be achieved and will eliminate, to the extent practical, the need for ongoing active maintenance of the disposal site following closure. The ER will be reviewed by the NRC and the impacts of LLW disposal evaluated in an Environmental Impact Statement (EIS) that is written for the specific LLW site. The technical requirements for land-disposal facilities are covered in Subpart D of 10 CFR Part 61. The financial assurance requirements are covered in Subpart E of 10 CFR Part 61.

- Activities related to the ENTOMBMENT Period:

  On October 16, 2001, the Commission issued an advance notice of proposed rulemaking (ANPR) inviting input from stakeholders on "Entombment options for Power Reactors" (66 FR 52551). Consistent with the environmental evaluation of the DECON and SAFSTOR decommissioning options, the staff has limited its environmental evaluation of ENTOMB to those issues related to activities necessary to prepare the facility for entombment.

  Issues and resulting impacts related to the ENTOMB option after the facility begins entombment, such as NRC oversight and monitoring requirements, durability of institutional controls and engineered barriers, indefinite retention onsite of radioactive materials, and other long-term site-specific issues are outside the scope of this Supplement.

  A future environmental assessment in support of NRC rulemaking related to the entombment options may address these issues depending on the proposed changes to the regulations.

- Activities following license termination under restricted use conditions: Licensees are allowed by regulations in 10 CFR Part 20, Subpart E, "Radiological Criteria for License Termination," to release the site for restricted use. The impacts following a restricted release license termination will not be considered by this Supplement because the licensee is required to conduct a site-specific analysis to support development of an NRC site-specific EIS.

- Activities and impacts from living or working on the site after license termination: Analysis of radiological impacts from unrestricted use after decommissioning and license termination are presented in NUREG-1496, *Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities* (NRC 1997). This GEIS analyzed regulatory

alternatives for establishing radiological criteria for decommissioning structures and lands of licensed facilities. The scope included both radiological and nonradiological impacts on human health and safety, including radiation exposure resulting from occupancy of site buildings and residence on site lands following decommissioning and license termination.

D.1 References

10 CFR 20. Code of Federal Regulations, Title 10, *Energy*, Part 20, "Standards for protection against radiation."

10 CFR 50. Code of Federal Regulations, Title 10, *Energy*, Part 50, "Domestic licensing of production and initialization facilities."

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, "Environmental protection regulations for domestic licensing and related regulatory functions."

10 CFR 61. Code of Federal Regulations, Title 10, *Energy*, Part 61, "Licensing requirements for land disposal of radioactive waste."

10 CFR 63. Code of Federal Regulations, Title 10, *Energy*, Part 63, "Disposal of high-level radioactive wastes in a geologic repository at Yucca Mountain, Nevada."

10 CFR 71. Code of Federal Regulations, Title 10, *Energy*, Part 71, "Packaging and transportation of radioactive material."

10 CFR 72. Code of Federal Regulations, Title 10, *Energy*, Part 72, "Licensing requirements for the independent storage of spent nuclear fuel and high-level radioactive waste."

54 FR 39767. "10 CFR Part 51 Waste Confidence Decision Review." *Federal Register*. September 28, 1989.

64 FR 8640. "10 CFR Parts 2, 19, 20, 21, 30, 40, 51, 60, 61, and 63 Disposal of High-Level Radioactive Wastes in a Proposed Geologic Repository at Yucca Mountain, Nevada." *Federal Register*. February 22, 1999.

64 FR 68005. "Waste Confidence Decision Review." *Federal Register*. December 6, 1999.

66 FR 51823. "Interim Storage for Greater Than Class C Waste 10 CFR Parts 30, 70, 72, and 150." *Federal Register*. October 11, 2001.

66 FR 52551. "Entombment Options for Power Reactors." *Federal Register*. October 16, 2001.

Nuclear Waste Policy Act of 1982, as amended, 42 USC 10.101 et seq.

U.S. Nuclear Regulatory Commission (NRC). 1982. *Final Generic Environmental Impact Statement for 10 CFR Part 61*. NUREG-0945, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1988. *Final Generic Environmental Impact Statement for Decommissioning of Nuclear Facilities*. NUREG-0586, NRC, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1997. *Final Generic Environmental Impact Statement in Support of Rulemaking on Radiological Criteria for License Termination of NRC-Licensed Nuclear Facilities*. NUREG-1496, Vol. 1, NRC, Washington, D.C.

EXHIBIT 36

August 12, 2016

Via U.S. Mail and Email

Cynthia Herzog
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California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825
Email: CEQAcomments@slc.ca.gov

Marlayna Vaaler, Project Manager
U.S. Nuclear Regulatory Commission
Office of Nuclear Material Safety and Safeguards
Washington, DC 20555-0001
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Subject: Environmental Review Scoping Comments for the San Onofre Nuclear Generating Station Units 2 & 3 Post-Shutdown Decommissioning Project

Dear Ms. Herzog:

On behalf of the City of Laguna Beach ("City"), this letter provides preliminary scoping comments on the Notice of Preparation ("NOP") of a draft environmental impact report ("DEIR") for the San Onofre Nuclear Generating Station Units 2 & 3 Post-Shutdown Decommissioning Project ("Project).

A portion of the proposed Project is located within the jurisdiction of the California State Lands Commission ("SLC"), on land within the Marine Corps Base Camp Pendleton, three (3) miles south of the community of San Clemente, west of Interstate 5 (I-5) and adjacent to the Pacific Ocean in northern San Diego County. The Project consists of the following four phases:

- Phase 1 – Decontamination and Dismantlement (2017-2025);
- Phase 2 – Partial Site Restoration and Offshore Conduit Disposition (2020-2035);
- Phase 3 – ISFSI Operation and Maintenance (2035-2049); and
- Phase 4 – Phase 4: ISFSI Removal and Final Site Restoration (2049-2051).

According to the NOP, the Project has the potential to cause a number of significant short-term, long-term and cumulative environmental impacts. The SLC, as the lead agency under the California Environmental Quality Act ("CEQA"),[1] has correctly determined that an EIR is required. As a responsible agency under CEQA and a cooperating agency under the National Environmental Policy Act ("NEPA"),[2] the City respectfully submits the following scoping comments.

[1] Pub. Res. Code §§ 21000 *et seq.*; *see also* Cal. Code Regs., tit. 14, ch. 3, § 15000 et seq. ("CEQA Guidelines").

[2] 42 USC §§ 4341 et seq.; *see also* Council on Environmental Quality ("CEQ") NEPA Regulations, contained in 40 C.F.R. Parts 1500-1508.

1. Consultation with the City concerning this Project's traffic, recreation, and open space impacts is required.

On July 12, 2016, the City of Laguna Beach became aware of the Project when City staff received the NOP. Section 15083 of the CEQA Guidelines encourages lead agencies to consult with other interested parties early in the environmental review process. The NOP solicits input from such interested parties, including the City. The City hereby submits these comments within the period requested in the NOP.

Because the Project is one of regional and areawide significance, a scoping meeting is required pursuant to Public Resources Code, section 21083.9(a)(2). Further, because the City exercises authority over resources that may be affected by the Project, including transportation facilities within its jurisdiction that could be affected, the SLC is required to consult with the City concerning potential effects to those resources.[3] We hereby request consultation concerning the Project's impacts to all potentially impacted transportation facilities within the City and to the area's beaches, adjacent ocean resources, open space and wildlife habitat resources.

Pursuant to Public Resources Code, section 21092.2, we also request notice of all stages of environmental review for the Project and any and all actions that the SLC proposes to take on this Project. Please send any and all notices via email to the following persons:

a) Mike Phillips, Environmental Specialist, at mphillips@lagunabeachcity.net;
b) Christa Johnson, Assistant City Manager, cjohnson@lagunabeachcity.net; and
c) Jason Holder, outside legal counsel retained for this matter, jason@holderecolaw.com.

Additionally, please send paper copies of notice documents solely to the undersigned.

2. Because the Nuclear Regulatory Commission Must Ultimately Approve the Decommissioning Project, There is a Federal Nexus Triggering the Need for a Joint EIR/EIS.

The Project is subject to oversight and review by the U.S. Nuclear Regulatory Commission ("NRC") under Title 10 of the Code of Federal Regulation, Part 50, Section 50.59 (10 CFR 50.59), applying to design changes, tests and experiments carried out at licensed nuclear facilities. The Project involves design changes to SONGS that will ultimately require NRC approval. For example, the NRC will have to approve SCE's license termination plan. Arguably, the Project also requires a license amendment.[4] When it fulfills its statutory duties,

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[3] PRC, § 21092.4; CEQA Guidelines, § 15086(a).

[4] For example, the NRC has not approved the design of the Holtec UMAX system that SCE has proposed for the ISFSI, and that partially subterranean design may reduce radiation safety. The proposed changes and alterations to the SONGS facility's design associated with decommissioning, including the Spent Fuel Pool Island Project ("SFPI") and the expanded and modified Independent Spent Fuel Storage Installation ("ISFSI"), require a license amendment because these changes were never addressed in the SONGS Final Safety Analysis Report ("FSAR") or any of the updates to the FSAR. *See* 10 C.F.R. §§ 50.56, 50.59(c). In addition, the Updated FSAR also does not consider the effects of sea level rise caused by

NRC will be the federal lead agency for review of the Project pursuant to NEPA. To adequately address the environmental impacts of the whole of the Project, SLC and NRC should jointly prepare an EIR/EIS for the Project. (*See* CEQA Guidelines, §§ 15006(j), 15170, 15220, 15222.) The CEQA Guidelines are clear:

> If a Lead Agency finds that an [Environmental Impact Statement ("EIS")] or Finding of No Significant Impact for a project would not be prepared by the federal agency by the time when the Lead Agency will need to consider an EIR or Negative Declaration, the Lead Agency should try to prepare a combined EIR-EIS or Negative Declaration-Finding of No Significant Impact. To avoid the need for the federal agency to prepare a separate document for the same project, the Lead Agency must involve the federal agency in the preparation of the joint document.
>
> This involvement is necessary because federal law generally prohibits a federal agency from using an EIR prepared by a state agency unless the federal agency was involved in the preparation of the document.[5]

Similarly, the CEQA regulations for implementing NEPA encourage cooperation with state and local agencies in an effort to reduce duplication in the NEPA process.[6]

In the required Draft EIR/Environmental Impact Statement ("DEIR/S"), NRC should fully address the radiological safety concerns that are purportedly preempted by federal law.[7] This is the elephant in the room that can no longer be concealed or brushed aside under a blanket claim of federal preemption. The public's interests and legal rights to understand the full environmental impacts of the decommissioning process will be circumvented if radiological safety issues are not addressed in the DEIR/S analysis.

When conducting this analysis, NRC will have to analyze site-specific radiological safety concerns.[8] The NRC's past "generic" EIS documents do not satisfy the requirement for detailed impact analysis. These boilerplate analyses do not address the specific circumstances that make SONGS decommissioning particularly worrisome to neighboring stakeholders, including the City's residents, businesses, and visitors. In *Natural Resources Defense Council v. Morton*, the

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climate change and associated reductions of radiation safety at SONGS. *See* SONGS FSAR, Hydrologic Engineering Chapter, available at: http://www.nrc.gov/docs/ML1114/ML11145A032.pdf.

[5] CEQA Guidelines, § 15222; *see also id* at §§ 15226, 15228.

[6] 40 CFR § 1506.2.

[7] As discussed further below, when recently approving the ISFSI, the California Coastal Commission did not analyze the "radiological safety" impacts of spent fuel storage casks based on a claim of federal preemption. (*See* Addendum to CCC Staff Report, dated Oct. 5, 2015 (CCC ISFSI Addendum), pp. 10-11, available at: http://documents.coastal.ca.gov/reports/2015/10/Tu14a-10-2015.pdf.) Comments made to the Coastal Commission and included in the CCC ISFSI Addendum are hereby incorporated herein by reference.

[8] The 2002 Supplement to NRC's *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* (NUREG-0586 Supplement 1) (the "Supplement") does not address storing spent fuel in a seismically active marine environment such as that characterizing the Project site. *See generally* Supplement, available at: http://www.nrc.gov/docs/ML0234/ML023470304.pdf.

Bureau of Land Management attempted to grant individual licenses, relying solely on a program EIS for the entire licensing program.[9] The court found that the program EIS failed to provide the decisionmaker with information regarding the specific and particular consequences of the action.[10] A similar finding was made by the court in *Natural Resources Defense Council v. Administrator*: "As a general rule, the preparation of a [program EIS] does not obviate the necessity of preparing a particularized impact statement for individual major federal actions that are components of a subject program."[11] Several courts have confirmed that site-specific environmental analyses are required before a lead agency can dispense with environmental review.[12]

Here, the NRC's Supplement generically analyzing the impacts of decommissioning identified two categories of impacts to be site-specific: threatened and endangered species and environmental justice. These issues must be addressed in the DEIR/S for this Project. It also identified four categories of impacts that it termed "conditionally site-specific":

- Land use involving offsite areas to support decommissioning activities
- Aquatic ecology for activities beyond the operational area
- Terrestrial ecology for activities beyond the operational area
- Cultural and historic resources for activities beyond the operational area with no current cultural and historic resource survey.[13]

The Supplement also concluded that environmental justice impacts must be determined on a site-specific basis.[14] The DEIR/S required for this Project must also address each of these site-specific impact categories and any others implicated by the proposed actions.

The NRC's Supplement also acknowledged site-specific analysis would be required when circumstances for decommissioning are unusual. Additionally, the NRC's more recent *Generic EIS for Continued Storage of Spent Nuclear Fuel* acknowledged that prior studies did not consider seismic risks at western nuclear reactors including San Onofre.[15] Here, because the Project site is located in a seismically active area and is immediately adjacent to a sensitive

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[9] *Natural Resources Defense Council v. Morton* (1974) 388 F.Supp. 829.

[10] *Id.* at 838.

[11] *Natural Resources Defense Council v. Administrator* (1978) 451 F.Supp. 1245, 1258.

[12] The Ninth Circuit of the U.S. Court of Appeals, which includes California, adopted similar reasoning. (*See, Natural Resources Defense Council v. Hodel* (9th Cir. 1987) 819 F.2d 927, 928 (refers to *NRDC v. Morton, supra*, as "the leading case in this area"); *City of Tenakee Springs v. Block* (9th Cir. 1985) 778 F.2d 1402, 1407 ("[w]here there are large-scale plans for regional development, NEPA requires both a programmatic and a site-specific EIS"); *Oregon Environmental Council v. Kunzman* (9th Cir. 1983) 714 F.2d 901 (Oregon Department of Agriculture ordered to prepare site-specific EIS for herbicide spraying program and had erred in relying on earlier program EIS).

[13] Supplement, p. xvi.

[14] *Id.* at p. 4-65.

[15] *See NRC Generic EIS for Continued Storage of Spent Nuclear Fuel* (NUREG–2157), pp. xlii, F-10 fn. 5, available at: http://www.nrc.gov/docs/ML1419/ML14196A105.pdf.

marine ecosystem, the site-specific analysis must consider the associated risks of radiological contamination.

In September 2014, SCE submitted a post-shutdown decommissioning activities report ("PSDAR"), the licensee's required analysis of the extent to which the Project's impacts are covered by the analysis in NRC's Supplement.[16] In its PSDAR, SCE asserted that "[b]ased on current plans, no decommissioning activities unique to the site have been identified and no activities or environmental impacts outside the bounds considered in the GEIS have been identified."[17] The City strenuously disagrees with this conclusion and requests that the NRC conduct an independent assessment of the extent to which the environmental impacts of the Project require site-specific analysis in the DEIR/S, especially given the Project's unique environmental setting.

When engaging in further consultation with the City and other concerned stakeholders, please confirm that the SLC and NRC will prepare a joint DEIR/S that will address radiological safety issues and will support the analysis with substantial evidence.

3. <u>The DEIR/S Must Analyze the Impacts of the Whole Project.</u>

Both CEQA and NEPA require lead agencies to analyze the impacts of the "whole of the project."[18] Here, the whole of the project is the entire decommissioning process. The NRC defines "decommission" in 10 CFR 50.2 as a process "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits (1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." This process necessarily includes each step following the decision to cease operations to the termination of the NRC license. Indeed, in its PSDAR, SCE admits that the decommissioning process necessarily includes Spent Nuclear Fuel Management Periods.[19]

Unfortunately, there has already been a pattern of piecemealed review and approval of various smaller "projects" that are in actuality inextricably connected to SONGS decommissioning. For example, the CPUC approved SCE's decommissioning cost estimate in December 2014. This decision was not preceded by any environmental impact analysis. Then,

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[16] *See* SCE's PSDAR for SONGS, available at: http://www.nrc.gov/docs/ML1426/ML14269A033.pdf.

[17] *See id.* at p. 8. The PSDAR is ostensibly supported by SCE's Environmental Impact Evaluation ("EIE"). *See* PSDAR for SONGS, p. 18. Like the PSDAR, the EIE concluded that "SCE's review confirmed that the anticipated or potential impacts are within the bounds of the generic impacts that the NRC described in the decommissioning GEIS." *See* EIE, p. ES-3, available at: https://www.songscommunity.com/docs/eieaug1.pdf. The EIE, however, provides only a cursory review of potential environmental impacts from the Project applicant's undeniable self-interested perspective, and that review relies on multiple unsupported assumptions. An independent review of Project impacts, conducted by state and federal agencies, is required.

[18] *See* CEQA Guidelines § 15378(a) [a "project" means the whole of an action that may cause either a direct or reasonably foreseeable indirect physical change in the environment]; *see also McQueen v. Board of Directors of the Midpeninsula Regional Open Space District* (1988) 202 Cal.App.3d 1136, 1143; *see also Thomas v. Peterson*, 753 F.2d 754 (9th Cit. 1985); *see also Save Yaak Comm. v. Block*, 840 F.2d 714 (9th Cir. 1988).

[19] *See* SCE's PSDAR for SONGS, p. 8.

in 2015, the Coastal Commission approved the SFPI and several months later approved the ISFSI for SONGS. These components of the overall decommissioning project should have been analyzed together in a single EIR/S. Instead, their individual effects have been minimized by chopping up the larger project into smaller pieces.

The DEIR/S must analyze the impacts of all phases of decommissioning, including the SFPI and the ISFSI. Again, the public's interests and legal rights to understand the full environmental impacts of the SONGS decommissioning process will be thwarted if the DEIR/S analysis does not consider all necessary aspects of decommissioning.

4. The SLC Has Broad Authority to Analyze Radiological Safety Issues and to Regulate Non-Radioactive Health and Safety Issues.

As noted above, the City recognizes that some of the issues identified above may be considered radiologic safety issues that could be preempted under federal law. The Coastal Commission did not analyze many safety issues raised by commenters based on a claim of federal preemption. Specifically, it asserted:

> Without assessing the validity of these concerns, the Commission staff notes that the consequences of any failure, malfunction, or defects in the proposed cooling system are related to radiological safety, which is under the exclusive jurisdiction of the federal [NRC]. [20]

While a state agency may be prevented from imposing restrictions on nuclear power plants based on federal preemption, nothing prevents the state agency from analyzing radiological safety issues and recommending restrictions (i.e., mitigation measures and alternatives) that the NRC can and should adopt.

Further, while both federal and state regulatory agencies have oversight over nuclear power facilities, it is well-settled that state regulators maintain their traditional authority to regulate non-radioactive health and safety issues, including land-use, environmental, and economic concerns associated with nuclear power generation.[21] SLC regulatory action for this Project is not preempted when motivated by non-preempted concerns and when it neither conflicts with nor frustrates the Congressional purpose of the Atomic Energy Act ("AEA").[22] Thus, even if the NRC does not presently assume its proper role as co-lead agency for this Project, for purposes of performing the analysis of radiological safety impacts, SCE must satisfy its duty to analyze non-radioactive health and safety issues.

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[20] CCC ISFSI Addendum, pp. 10-11.

[21] *Pacific Gas & Electric Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205, 212 (1983) (*PG&E*).

[22] *Id.* at 220-223.

5. The DEIR/S must adequately analyze the Project's potentially significant impacts to marine life, air and water quality, City transportation and recreation facilities, and it must consider secondary impacts and analyze a reasonable range of Project alternatives.

The DEIR/S must include thorough analysis of the following potentially significant environmental impacts that could affect the City and its residents:

a) Demolition impacts – Impacts to air and ocean water quality during demolition of Units 2 & 3 reactor structures

b) Damage to roadways and other infrastructure caused by the transportation of structures, systems, and components ("SSCs"), hazardous materials, and any contaminated soils and water[23]

c) Impacts to groundwater supplies caused by potential radiation contamination and contamination that may have already occurred

d) Impacts associated with disposing of spent fuel pool water – Discussion of how contaminated water from the spent fuel cooling pool is disposed of after rods are removed

e) Impacts to special status species

The NOP acknowledges that four special-status reptiles have the potential to occur within the offshore Project area and that several other special-status species have the potential to occur within the onshore Project site.[24]

f) Impacts to marine life if cooling system intake and discharge conduits, and the fish return system conduit are left partially or completely in place

g) Seismic-related hazards associated with the storage of spent nuclear fuel storage casks for at least 20 years and quite possibly longer[25]

h) Impacts that may occur if the dry storage casks in the ISFSI crack and release radiological contamination

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[23] SCE's EIE states that decommissioning will involve the transportation of millions of cubic feet of radioactive and nonradioactive waste. *See* EIE, p. ES-16. It then explains that "SCE plans to ship the bulk of radiological waste by rail; however, there may be times when truck shipments will be required." *Ibid.*

[24] *See* NOP, Attachment, p. 19.

[25] In a June 2015 staff report, Coastal Commission staff noted that "Though SCE seeks temporary development authorization until 2051, there is no assurance that SCE will be able to transfer the spent fuel to DOE custody and decommission the proposed facility as planned by 2051, complicating the analysis of the project's exposure to geologic hazards and its potential to adversely affect coastal resources. The uncertain duration of the ISFSI's presence at the proposed location also has implications for SCE's alternatives analysis…." (CCC ISFSI Addendum, Staff Report, p. 20.)

i) Cumulative impacts – Please address the potential impacts to the surrounding environment (earth, land, sea, air) of short-term, long-term, and indefinite storage of spent nuclear fuel on the Project site.

j) Mitigation Measures – please include measures to reduce or eliminate all potentially significant Project impacts

If the SLC concludes that mitigation measures are within the responsibility and jurisdiction of another agency, such as the NRC, then it must recommend that those measures "can and should" be adopted by that agency.

k) Weekday and peak traffic impacts on all surrounding roads and intersections caused by transporting SSCs, spent nuclear fuel storage casks, and any contaminated soils and water

l) Weekend and off-peak traffic impacts on Highway 1 and SR 133 (Laguna Canyon Road)

m) Impacts on the City's recreation facilities including its beaches and shoreline caused by the Project[26]

n) Public service impacts to the City's residents, including any reduced police, fire, or ambulance services or increased response times caused by Project activities[27]

o) Secondary impacts caused by increased Project traffic, including air quality impacts and increased greenhouse gas (GHG) emissions

p) Consideration of a reasonable range of Project alternatives, including options for removal of the dry storage casks from the Project site and to either a Consolidated Interim Storage ("CIS") location or to a permanent spent nuclear fuel storage facility

Please include all technical support for the above analyses in appendices to the DEIR/S.

* * *

We request that the SLC and NRC provide a joint environmental impact analysis that considers the Project in its entirety. The requested DEIR/S must enable fulfillment of duties to protect communities and natural resources by considering and minimizing all potentially

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[26] The NOP indicates that SLC staff has concluded that the Project would not have any potentially significant impacts to recreation. (NOP, p. 18.) This conclusion is incorrect and is unsupported by substantial evidence. Because the Project is located adjacent to the Pacific Ocean and near several state beaches, it has the potential to impact these recreation facilities. Those impacts must be analyzed in the DEIR/S and mitigated to the extent feasible.

[27] Again, the NOP indicates that SLC staff has concluded that the Project would not have any potentially significant impacts to public services. (NOP, p. 18.) This conclusion is similarly incorrect and is also unsupported by substantial evidence.

significant impacts of the Project, including those that have heretofore been disregarded as the exclusive province of the federal government.

If you have any questions concerning these comments, please contact Michael Phillips at (949) 497-0390 and at mphillips@lagunabeachcity.net.

Sincerely,

John Pietig
City Manager

cc: (via email only)
City Council
Christa Johnson, Assistant City Manager
David Shissler, Director of Water Quality
Mike Phillips, Environmental Specialist
Jason Holder, outside legal counsel

EXHIBIT 37

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 5, 2018

Ms. Cynthia Herzog
Senior Environmental Scientist
California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825

SUBJECT: ADDITIONAL INFORMATION REGARDING THE CALIFORNIA STATE LANDS COMMISSION RESPONSE TO THE CITY OF LAGUNA BEACH ENVIRONMENTAL REVIEW PUBLIC SCOPING COMMENTS FOR THE SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3, DECOMMISSIONING PROJECT

Dear Ms. Herzog:

Thank you for the opportunity to review the Draft Environmental Impact Report (EIR) prepared by the California State Lands Commission (CSLC) in regard to the San Onofre Nuclear Generating Station, Units 2 and 3 (SONGS), Decommissioning Project, which was released on June 27, 2018. The operator of SONGS, Southern California Edison (SCE), holds facility operating licenses from the U.S. Nuclear Regulatory Commission (NRC). As noted in your correspondence, the CSLC, as the lead agency under the California Environmental Quality Act (CEQA), has determined that an EIR is required for the SONGS decommissioning project, and is currently soliciting feedback on the Draft EIR. While I understand that the public comment period on the Draft EIR closed on August 28, 2018, I hope that this additional information from the NRC staff will be useful to the CSLC as you move forward with the CEQA process.

In Appendix C of the Draft EIR, the CSLC has dispositioned public scoping comments received as a result of the Notice of Preparation issued on June 12, 2016, regarding the scope and content of the EIR for the SONGS decommissioning project. One of the comment letters, dated August 12, 2016, was received from the City of Laguna Beach, California (the City) and addressed to both the CSLC and the NRC. This letter included numerous comments on the ongoing decommissioning activities at SONGS, and made several requests of the CSLC and the NRC with respect to environmental oversight during this process.

In order to facilitate your ongoing review and finalization of the Draft EIR for the SONGS decommissioning project, in the attachment to this letter, the NRC staff has provided some additional information in support of your disposition of the City's comments. The City's letter, as well as other publicly available documents referenced in the attachment, can be found in the NRC's document repository at Agencywide Documents Access and Management System (ADAMS). You may obtain publicly available documents online in the ADAMS Public Documents collection at http://www.nrc.gov/reading-rm/adams.html. To begin the search, select "ADAMS Public Documents" and then select "Begin Web-based ADAMS Search."

If you have any additional questions or clarifications regarding the information provided in the attachment to this letter, please contact the SONGS decommissioning project manager, Marlayna Vaaler, at 301-415-3178, or via email at marlayna.vaaler@nrc.gov.

Sincerely,

/RA/

Bruce A. Watson, CHP, Chief
Reactor Decommissioning Branch
Division of Decommissioning, Uranium Recovery, and Waste Programs
Office of Nuclear Material Safety and Safeguards

Docket Nos. 50-361 and 50-362

Attachment: Supplemental Information Regarding the CSLC Responses to the City of Laguna Beach's Comments on the Scope and Content of the EIR for the SONGS Decommissioning Project

cc: electronic Distribution via Listserv

Additional hard copies to:

Mr. Thomas J. Palmisano
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San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

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City Manager
City of Laguna Beach
505 Forest Avenue
Laguna Beach, CA 92651

Supplemental Information Regarding the CSLC Responses to the City of Laguna Beach's Comments on the Scope and Content of the EIR for the SONGS Decommissioning Project

CSLC Responses to Comments from the City of Laguna Beach (City)

In Appendix C of the Draft EIR for the SONGS decommissioning project, the CSLC has identified the City's August 12, 2016, letter as "Comment Set 7" and has identified seven specific comments within the letter. The CSLC has designated these seven comments from the City's letter as #7-1 to #7-7. The NRC staff appreciates the CSLC's specific responses to comments #7-1 to #7-7 and concurs with them. In addition, the NRC staff recommends that the CLSC comment responses be further supplemented as follows:

1. Role of the NRC

The NRC's mission is set forth in its organic statutory authority, the Atomic Energy Act of 1954, as amended (AEA).[1] Under the AEA, the NRC is charged with regulating the civilian use of radioactive material. Thus, the NRC's regulatory program concerns protecting human health and property from the dangers of radioactivity that could potentially arise from such civilian use, and for ensuring the physical security of radioactive material under the ownership or control of its licensees. The NRC accomplishes its mission through a comprehensive radiation protection program for both members of the public and occupational workers (e.g., workers at a nuclear power plant). The NRC regulates its licensees through regulation, license terms and conditions, and through a robust inspection and enforcement program.[2] The NRC also provides extensive guidance documents to assist its licensees with regulatory compliance. The construction and operation of a nuclear power plant, and the associated use and possession of radioactive material at the plant requires a facility operating license from the NRC.[3]

Once licensed, the NRC is responsible for ensuring that a nuclear power plant licensee meets the applicable NRC radiation protection requirements, including those set forth in the NRC's 10 CFR Part 20 and 50 regulations, and maintains the required level of physical security and emergency preparedness for the licensed site and the radioactive material under its control. The NRC, however, is not responsible for operating the plant; nor does the NRC own or otherwise control the radioactive material on site. Likewise, the NRC does not hold any real property interest in the licensed site itself; nor does it have any land management authority over the site. In addition, the NRC has no role in the ultimate disposition or use of the site after the facility operating license is terminated.

The regulation of non-radioactive material or non-radioactive pollutants at a nuclear power plant is also outside the scope of the NRC's regulatory authority. Further, the NRC only has regulatory authority over those portions of a nuclear power plant that contain or process radioactive material or have a role in the nuclear fission (electricity generating) process, such as the buildings housing the reactor vessel, the spent fuel pool, and the control room. Other than

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1 42 [United States Code] U.S.C. §§ 2011 *et seq*.

2 The NRC's general radiation protection regulations, applicable to all licensees, are set in Title 10 of the *Code of Federal Regulations* (10 CFR) Part 20, "Standards for Protection Against Radiation." The NRC's regulations concerning the licensing of nuclear power plants like SONGS, including decommissioning, are set forth in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."

3 42 U.S.C. § 2133.

ensuring that the licensee meets the requisite physical security requirements for the facility, or those requirements concerning the transport of radioactive material into and out of the licensed facility, the NRC does not have regulatory authority over the licensee's visitor center, administrative office spaces, cafeteria, roads, parking lots, daycare centers, and other buildings and structures that have no role in either holding, storing, or processing radioactive material.

In this regard, the NRC is not the only regulator of a nuclear power plant facility; several other federal, state, and local agencies typically have regulatory or permitting roles. For example, the licensee must meet the requirements of the Clean Water Act, requiring the licensee to obtain a National Pollutant Discharge Elimination System (NPDES) permit from either the United States Environmental Protection Agency (EPA), or if delegated by the EPA, the appropriate state agency. To the extent there are wetlands on the licensed site, the licensee must obtain the appropriate permit from the United States Army Corps of Engineers. The licensee must satisfy the requirements of all applicable state and local health, safety, and environmental protection laws—those laws are implemented and enforced by the applicable state agencies. Finally, the licensee must satisfy all local or municipal zoning ordinances.

Role of the NRC During Decommissioning and License Termination

In terms of decommissioning, the nuclear power plant licensee must first certify to the NRC that it has permanently stopped operating (i.e., stopped generating electricity by nuclear fission) and that it has removed all nuclear fuel from the reactor vessel.[4] The decommissioning process usually lasts several years, possibly decades, and under the applicable NRC regulation, can take up to sixty years.[5] At the end of the decommissioning process, the licensee will seek to terminate its operating license. The NRC will terminate the license if the licensee demonstrates that it has reduced the residual radioactivity at the licensed site to acceptable levels, i.e., those set forth in Subpart E, "Radiological Criteria for License Termination," of 10 CFR Part 20, "Standards for Protection Against Radiation." SCE has informed the NRC that it intends to pursue license termination in accordance with 10 CFR 20.1402, "Radiological criteria for unrestricted use."[6] Section 20.1402 states, in part,

> A site will be considered acceptable for unrestricted use if the residual radioactivity that is distinguishable from background radiation results in a [total effective dose equivalent][7] to an average member of the critical group[8] that does not exceed 25 mrem (0.25 mSv) per year, including that from groundwater

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4 10 CFR 50.82(a)(1)(i)-(ii).

5 10 CFR 50.82(a)(3).

6 As explained in item 3 below, SCE will continue to operate one small portion of its current licensed site, the independent spent fuel storage installation (ISFSI), indefinitely. Thus, the SCE operating license will, in effect, be reduced to the area of the ISFSI upon successful completion of the decommissioning process for the remainder of the licensed site.

7 "Total effective dose equivalent" or TEDE, is defined as "the sum of the effective dose equivalent (for external exposures) and the committed effective dose equivalent (for internal exposures)." 10 CFR 20.1003. The terms "effective dose equivalent" and "committed effective dose equivalent" are also defined in 10 CFR 20.1003, which is the definitions section for 10 CFR Part 20.

8 "Critical group" is defined as "group of individuals reasonably expected to receive the greatest exposure to residual radioactivity for any applicable set of circumstances." 10 CFR 20.1003.

> sources of drinking water, and the residual radioactivity has been reduced to levels that are as low as reasonably achievable (ALARA).[9]

Thus, whether the licensee has demonstrated to the NRC that it has reduced the site's level of residual radioactivity to the standard specified in 10 CFR 20.1402[10] *is the only factor* that the NRC considers in determining whether the license can be terminated.[11]

Ensuring that the licensee safely meets the regulatory level of residual radioactivity for license termination is the goal of decommissioning. In this regard, "decommissioning" itself is the process by which the licensee reduces the site's residual radioactivity to the regulatory level by removing or otherwise mitigating on-site radiological contamination.[12] Thus, the presence of non-radioactive contaminants on the site (e.g., PCBs, asbestos, lead-based paint), and the remediation or mitigation of such non-radiological hazards, are beyond the scope of the NRC's regulatory authority. Similarly, whether the licensee dismantles and demolishes the facility's buildings and structures, or chooses to leave them standing as part of the decommissioning process, is not within the NRC's purview. The NRC's regulatory objective is that the licensee meets all applicable NRC public and occupational radiological safety requirements throughout the decommissioning process, and that at the completion of that process the licensee is able to demonstrate the requisite level of residual radioactivity.

2. Environmental Impacts of Decommissioning have been Previously Analyzed and are Not Significant

In its August 12, 2016, letter, the City asserts that the NRC must analyze the site-specific radiological safety concerns associated with the SONGS decommissioning project in a site-specific NEPA document, and that the agency's generic NEPA decommissioning analyses are not sufficient. The analyses conducted by the NRC in support of the decommissioning of nuclear power reactors are set forth in the "Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," NUREG-0586 (1988), as supplemented and updated by the "Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities," NUREG-0586, Supplement 1 (2002) (collectively, the Decommissioning GEIS).[13] As explained below, the NRC disagrees with these assertions.

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9 10 CFR 20.1402 (alteration added). The term ALARA is defined in 10 CFR 20.1003 and the NRC's ALARA requirements are generally defined in 10 CFR 20.1101, "Radiation protection programs."

10 The NRC defines "residual radioactivity" as "radioactivity in structures, materials, soils, groundwater, and other media at a site resulting from activities under the licensee's control. This includes radioactivity from all licensed and unlicensed sources used by the licensee, but excludes background radiation. It also includes radioactive materials remaining at the site as a result of routine or accidental releases of radioactive material at the site and previous burials at the site, even if those burials were made in accordance with the provisions of 10 CFR part 20." 10 CFR 20.1402.

11 As explained in item 3 below, the SCE operating license will be reduced to the area of the ISFSI and will remain in effect, indefinitely, for the ISFSI only. The NRC will apply the 10 CFR 20.1402 residual radioactivity standard in determining whether the SONGS licensed site, except for the ISFSI, can be released for unrestricted use (i.e., released from the NRC license and hence, from NRC regulatory authority).

12 The NRC defines the term "decommission" as "to remove a facility or site safely from service and reduce residual radioactivity to a level that permits—(1) Release of the property for unrestricted use and termination of the license; or (2) Release of the property under restricted conditions and termination of the license." 10 CFR 50.2, "Definitions."

13 The "GEIS is considered 'generic' in that it evaluates impacts from decommissioning activities common to a number of nuclear power facilities." NUREG-0586, Supp. 1, at xi, n. (a); available at ADAMS Accession No. ML023500395.

1996 Decommissioning Rulemaking

In the preamble to the 1996 rulemaking that promulgated the NRC's current nuclear power plant decommissioning regulation (10 CFR 50.82, "Termination of license"), the NRC described its finding that nuclear power plants undergoing decommissioning present much lower radiological safety risks than operating nuclear power plants, primarily because nuclear fission is no longer occurring in the reactor vessel and all nuclear fuel assemblies have been permanently removed from the reactor vessel and placed into the facility's spent fuel pool.[14] Specifically, the NRC found that "the activities performed by the licensee during decommissioning do not have a significant potential to impact public health and safety and [therefore] require considerably less oversight by the NRC than during power operations."[15]

Additionally, the systems and processes required to safely maintain a decommissioning plant are much simpler than those required to run an operating plant.[16] For example, unlike an operating plant, a decommissioning plant will not draw in large quantities of cooling water, which after being run through the plant systems and processed as needed, is then released back into the environment. The gaseous and liquid radioactive effluents of a decommissioning plant, to the extent that there are any, will also be far more limited than those of an operating plant. The NRC determined that any environmental impacts were expected to be "minor" and that "[a]ny site impact should be bounded by the impacts evaluated by previous applicable GEISs as well as any site-specific [environmental impact statement (EIS)]."[17]

NRC's NEPA Compliance

The NRC fulfills its NEPA obligations with respect to the decommissioning of nuclear power plants through a combination of generic and site-specific environmental analyses. The NRC prepares a site-specific EIS to support construction and operation of the plant.[18] Subsequent to the issuance of the SONGS operating licenses in 1982, the NRC performed additional environmental reviews to support its decisions regarding the approval or disapproval of specific license amendment or exemption requests. The NRC documented these reviews in accordance with NEPA; specifically, the NRC staff would prepare an environmental assessment (EA) with a finding of no significant impact (FONSI).[19] In addition to the analyses set forth in these site-

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[14] 61 FR 39278, "Decommissioning of Nuclear Power Reactors," (July 29, 1996) at 39278-79. After several years in the spent fuel pool, spent fuel assemblies are typically removed from the pool and placed into "dry" storage in an ISFSI located on the site. SCE expects to transfer all spent fuel assemblies currently in the SONGS spent fuel pools to the onsite ISFSI by the end of 2018.

[15] *Id*., at 39279 (alteration added).

[16] *Id*.

[17] *Id*., at 39283 (alteration added).

[18] The results of the environmental reviews are typically provided as a "NUREG" document for each facility; NUREG-0490, "Final Environmental Statement related to the operation of San Onofre Nuclear Generating Station, Units 2 and 3", dated April 1981 (ADAMS Accession No. ML18239A414), is the EIS supporting the NRC's decision to issue the operating licenses for the SONGS, Units 2 and 3, facilities.

[19] *E.g.*, 61 FR 50513 (September 26, 1996) (EA/FONSI for amendments of operating licenses to allow an increase in fuel enrichment); 66 FR 32964 (June 19, 2001) (EA/FONSI for amendments of operating licenses to allow SCE to increase its maximum reactor core power level for both Units 2 and 3); 80 FR 21271 (April 17, 2015) (EA/FONSI for issuance of an exemption from emergency planning requirements due to SONGS being in a decommissioning status).

specific NEPA documents, some of which may remain applicable through the decommissioning process,[20] the decommissioning of SONGS is covered by the Decommissioning GEIS.

The Decommissioning GEIS is a comprehensive generic EIS that covers the potential environmental impacts likely to arise during decommissioning.[21] The NRC's prior operational experience served as the basis for the 1988 Decommissioning GEIS, and was supplemented with additional experience in conducting decommissioning during the 2002 update of the Decommissioning GEIS. The NRC has found that most potential environmental impacts resulting from decommissioning are common to all nuclear power plants and therefore, can be analyzed generically. Additionally, for all environmental impacts dispositioned generically, the NRC has found that decommissioning activities will have only "small" impacts (i.e., impacts that are not significant under NEPA). Therefore, decommissioning is not a "major Federal action" under NEPA.[22] In short, the NRC considers decommissioning activities to present such low safety and environmental risks that the only licensee decommissioning action triggering a required NRC decision (and as such, triggering a site-specific NEPA review) under 10 CFR 50.82 is the submission of a license termination plan (LTP), which the licensee is required to submit at least two years before the expected license termination date.[23] Thus, if a licensee does not submit any other license amendment or exemption requests during decommissioning, the only site-specific NRC NEPA review will be the one conducted for the LTP.

Since the Decommissioning GEIS was supplemented and updated in 2002, the NRC's operational experience has continued to show that the extensive, detailed analyses set forth in the Decommissioning GEIS will bound or account for most reasonably foreseeable, potential environmental impacts that may arise at any decommissioning plant, including SONGS.[24] As long as the licensee's decommissioning activities remain within the scope of the Decommissioning GEIS's analyses, or applicable site-specific NEPA analyses conducted in support of previous licensing actions, those activities will be "bounded" and the potential impacts will be considered to be previously analyzed and not significant for NEPA purposes.

The review of those potential site-specific decommissioning environmental impacts (i.e., those not dispositioned generically in the Decommissioning GEIS) are first addressed in the

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[20] For example, the June 2001 EA/FONSI analyzed the increase to water temperature resulting from the proposed increase of the maximum reactor core power level. The temperature increase would impact the cooling water discharged into the Pacific Ocean. As the increase in water temperature was within the limit on differential temperature allowed by the California Regional Water Quality Control Board, the increase was not found to be a significant environmental impact. As a decommissioning plant does not need water to cool its reactor, this EA/FONSI bounds any impacts to water temperature (at least with respect to temperature increases) arising from the SONGS decommissioning process, and complements the findings in the Decommissioning GEIS.

[21] In adjudicating a challenge to the NRC's use of generic NEPA analyses, the United States Supreme Court held that "[t]he generic method chosen by the agency is clearly an appropriate method of conducting the hard look required by NEPA." *Baltimore Gas and Electric Co., v. Natural Resources Defense Council*, 462 U.S. 87, 101 (1983).

[22] Council on Environmental Quality (CEQ) regulations define the terms "Major Federal action" and "Significantly." 40 CFR 1508.18 and 1508.27. The NRC has adopted these CEQ definitions. 10 CFR 51.14(b).

[23] 10 CFR 50.82(a)(9) (LTP requirements); 10 CFR 50.82(a)(10) (NRC approval requirements). During its review of the LTP, the NRC will prepare a safety evaluation and an EA, and if approved, the NRC will incorporate the LTP into the operating license via a license amendment.

[24] As of August 2018, the NRC has overseen the successful decommissioning of ten nuclear reactor units and is currently overseeing the decommissioning of twenty reactor units (several nuclear power plants, such as SONGS, have more than one reactor unit).

construction and operation EIS (in the case of SONGS, NUREG-0490, referenced above).[25] Additionally, such site-specific impacts would have been analyzed in the EA/FONSIs for license amendment or exemption requests during the plant's operation, such as those referenced above. Finally, during decommissioning, these site-specific impacts will be analyzed by the NRC staff in the appropriate NEPA document (most likely an EA but if necessary, an EIS) in the event the licensee submits a license amendment or exemption request, or after the licensee submits the license amendment request to approve the LTP.[26]

10 CFR 50.82

The NRC's NEPA compliance is supported by the requirements of 10 CFR 50.82. Section 50.82 prohibits a licensee from performing any decommissioning activity that would "result in significant environmental impacts not previously reviewed."[27] This provision was added by the 1996 rule "[t]o account for site-specific situations that may occur outside these environmental impact considerations;" the intent of this provision was to prohibit decommissioning activities that could result in significant environmental impacts not previously reviewed.[28]

The licensee is also required to submit to the NRC a post-shutdown decommissioning activities report (PSDAR), which is one of the regulatory prerequisites that must be satisfied before a licensee may begin decommissioning.[29] The NRC does not approve or disapprove the PSDAR; the submission of a PSDAR is a licensee reporting requirement. As such, the submission of the PSDAR does not result in an agency action. As there is no agency action, there is no requirement to perform a NEPA analysis on the licensee's PSDAR submission. The licensee, however, must include in the PSDAR "a discussion that provides the reasons for concluding that the environmental impacts associated with site-specific decommissioning activities will be bounded by appropriate previously issued environmental impact statements."[30] Although not approved, the NRC staff will still review the PSDAR and to extent that the NRC has concerns with the PSDAR's environmental compliance discussion or other required portions of the PSDAR, the NRC staff may request additional information from the licensee. Further, 10 CFR 50.82 requires a licensee to inform the NRC and affected States, in writing, before "performing any decommissioning activity inconsistent with, or making any significant schedule change from, those actions and schedules described in the PSDAR."[31]

Thus, if the licensee wishes to perform a decommissioning activity that would result in a significant impact not previously reviewed, the licensee would be required to submit a license

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[25] *E.g.*, NUREG-0490, § 5.2, "Impacts on Land Use," § 5.4.1, "Environmental Impacts/Terrestrial Environment," § 5.4.2, "Environmental Impacts/Impacts on the Aquatic Environment," § 5.5.2, "Radiological impacts on biota other than man," § 9.4, "Decommissioning," and Appendix D, "Cultural Resources."

[26] Any site-specific NEPA analysis prepared during decommissioning will rely on the Decommissioning GEIS' analyses for the generically dispositioned issues. In this regard, the site-specific NEPA analysis "tiers" off the Decommissioning GEIS. 40 CFR 1502.20 and 1508.28 (CEQ regulations); 10 CFR Part 51, Appendix A, 1(b) (adopted by NRC).

[27] 10 CFR 50.82(a)(6)(ii).

[28] 61 FR, at 39283.

[29] 10 CFR 50.82(a)(4)(i). Prior to the 1996 rule, licensees were required to submit a decommissioning plan, which was subject to NRC approval. The 1996 rule replaced the decommissioning plan with the PSDAR. 61 FR at 39279 ("A major change from the current rule is that power reactor licensees would no longer be required to have an approved decommissioning plan before being permitted to perform major decommissioning activities").

[30] 10 CFR 50.82(a)(4)(i).

[31] 10 CFR 50.82(a)(7).

amendment request or an exemption request. The NRC would then analyze the proposed action and prepare the necessary site-specific NEPA analysis. If the licensee wishes to perform a decommissioning activity that is otherwise inconsistent with the PSDAR, the licensee would be required to notify the NRC and affected States in writing before taking any action. The NRC and affected States would then have the opportunity to review the proposed action and request additional information from the licensee before the action is taken.

Preparation of a Joint EIR/Environmental Impact Statement (EIS)

In its August 12, 2016, letter, the City asserts that the NRC and the CSLC should prepare a joint EIR. In response, the NRC staff does not agree that it should prepare a joint EIR/EIS with CSLC (nor does the NRC need to prepare a "stand-alone" EIS). According to the draft EIR, the jurisdiction of the CSLC is "seaward of the ordinary high-water mark."[32] The proposed CSLC action concerns the disposition of submerged lands leased to SCE and the City of Riverside, California,[33] and the improvements thereon, namely, the SONGS, Units 2 and 3, offshore intake and discharge conduits and associated appurtenances, navigational and environmental monitoring buoys, and riprap along shore seaward of the ordinary high-water mark.[34]

Whether these improvements should remain in place indefinitely or be partially or wholly removed is a question that is not within the NRC's regulatory authority. As with any part of the NRC-licensed SCE site, the NRC's regulatory objective is that SCE be able to demonstrate that it has met the 10 CFR 20.1402 level of residual radioactivity at the conclusion of the decommissioning process.

SONGS PSDAR

In its August 12, 2016, letter, the City states that it disagrees with the conclusion reached by SCE in its PSDAR, submitted in September 2014 (ADAMS Accession No. ML14269A033). In its PSDAR, SCE stated that "[b]ased on current plans, no decommissioning activities unique to the site have been identified and no activities or environmental impacts outside the bounds considered in the GEIS have been identified."[35]

By letter dated August 20, 2015 (ADAMS Accession No. ML15204A383), the NRC acknowledged receipt of SCE's PSDAR, documented the review, and summarized comments received during the PSDAR public meeting held near the SONGS site in October 2014. In its August 20, 2015, letter, the NRC staff stated:

> [SCE] compared the SONGS, Units 2 and 3, facility to the reference facility in NUREG-0586 and found that the SONGS, Units 2 and 3, environmental impacts were bounded by the analysis provided in NUREG-0586. After reviewing [SCE's] comparison, the NRC staff finds that the potential environmental impacts associated with SONGS, Units 2 and 3, decommissioning activities are bounded by the previously issued GEIS and its [supplement], are described consistent

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32 CSLC, "Draft Environmental Impact Report for the San Onofre Nuclear Generating Station (SONGS) Units 2 & 3 Decommissioning Project," State Clearinghouse No. 2016071025, CSLC EIR No. 784 (June 2018) at ES-3.

33 The City of Riverside is not an NRC licensee and the NRC has no regulatory authority over the City of Riverside.

34 *Id.*, at ES-1.

35 SCE, PSDAR (September 23, 2014) at 8.

with the guidance in RG 1.185,[36] and meet the requirements of 10 CFR 50.82(a)(4)(i).[37]

The City has provided no information that any of the potential environmental impacts that may result from the planned decommissioning activities, as described in SCE's September 2014 PSDAR, are beyond the scope of the Decommissioning GEIS and other previously prepared NRC site-specific NEPA documents or are, in any other way, significant. In response to the City's assertion that the NRC must analyze the site-specific radiological safety issues, presumably in an EIS, the analyses provided in the Decommissioning GEIS are sufficient and bound any reasonably foreseeable impact.

Major Decommissioning Activities; NRC Oversight During Decommissioning

The NRC makes a distinction between an environmental issue, which is analyzed under NEPA, and a safety issue, for which the NRC is responsible under the AEA. Safety issues are analyzed in NRC safety reports, such as a nuclear power plant's final safety analysis report or FSAR, which is part of the plant's licensing basis, and is updated on a regular basis. Any changes that may impact the safety of the plant are evaluated by the NRC staff as part of the safety evaluation reports that accompany licensee requests for the approval of a license amendment or exemption request, or are otherwise reviewed by the NRC staff as part of the licensee reporting and NRC inspection processes. As a "safety" agency, the NRC handles safety issues as they arise on an ongoing and operational basis.

A licensee is prohibited from engaging in "major decommissioning activities" until ninety days after the submission of the PSDAR, provided that the licensee has submitted its 10 CFR 50.82(a)(1)(i)-(ii) certifications that it has permanently ceased operations and has removed all fuel assemblies from the reactor vessel.[38] Once the post-PSDAR ninety day period has run and the requisite certifications have been submitted to the NRC, the licensee may begin major decommissioning activities. The licensee does not need prior NRC approval to conduct such major decommissioning activities, provided that the licensee's activities remain within a certain defined scope, as prescribed by 10 CFR 50.59, "Changes, tests and experiments."[39]

During the decommissioning process, the NRC maintains comprehensive regulatory oversight over the plant. The licensee remains subject to the terms and conditions of its license, and as such, remains subject to NRC inspection and enforcement. As described in Inspection Manual Chapter (IMC) 2561, "Decommissioning Power Reactor Inspection Program" (ADAMS Accession No. ML17348A400), the NRC staff will engage in regular on-site inspections that

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36 Regulatory Guide (RG) 1.185, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report," Revision 1 (June 2013) (ADAMS Accession No. ML13140A038). RG 1.185 is an NRC guidance document developed to assist licensees in complying with the PSDAR requirements.

37 NRC, Letter to T.J. Palmisano, Vice President and Chief Nuclear Officer, SCE (August 20, 2015), at 5.

38 The term "major decommissioning activity" means, "for a nuclear power reactor facility, any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components for shipment containing greater than class C waste in accordance with § 61.55 of this chapter." 10 CFR 50.2.

39 Section 50.59 provides parameters by which a licensee may make certain changes to the facility without prior NRC approval. If the licensee's intended action will exceed the 10 CFR 50.59 parameters, the licensee must seek NRC approval before taking the action, typically in the form of a license amendment or exemption request. The NRC will then conduct a site-specific safety and environmental analysis (NEPA) prior to approving or disapproving the licensee's proposed action.

emphasize radiological controls and management, procedure compliance, spent fuel pool operation, and the safety review program. Many activities that occur during decommissioning are routine and occur frequently in operating plants. These include decontamination of surfaces and components, surveys for radioactive contamination, waste packaging and disposal, and other activities. During active decommissioning periods, NRC inspectors may be at the facility 2 or 3 weeks of the month in order to observe ongoing activities. During a long-term storage period, inspectors would be present to conduct inspections at least once a year in accordance with the decommissioning reactor inspection program outlined in IMC 2561.

The NRC has also issued several regulatory guidance documents for nuclear power plant decommissioning, including Regulatory Guide (RG) 1.184, "Decommissioning of Nuclear Power Reactors," Revision 1 (October 2013; ADAMS Accession No. ML13144A840); RG 1.185, "Standard Format and Content for Post-Shutdown Decommissioning Activities Report," Revision 1 (June 2013; ADAMS Accession No. ML13140A038)); and RG 4.21, "Minimization of Contamination and Radioactive Waste Generation: Life-Cycle Planning" (June 2008; ADAMS Accession No. ML080500187). The guidance is directed toward NRC licensees and provides suggested procedures and methodologies to meet the applicable NRC regulatory requirements during decommissioning. Although compliance with guidance is not required, licensees have an incentive to follow the procedures and methodologies set forth in the guidance documents as NRC practice is to presume that compliance with the guidance means that the licensee is in compliance with the applicable NRC regulation upon which the guidance is based (e.g., 10 CFR 50.82 and 10 CFR 20.1402).

Finally, the NRC's regular contact with the licensee during decommissioning, through its on-site inspection program and otherwise, allow the NRC and licensee to address, on a site-specific basis, any radiation related safety concern that may arise during the process. Based upon its operating experience, the NRC has determined that all expected and reasonably foreseeable safety issues for SONGS are bounded by the Decommissioning GEIS, the current SONGS licensing basis (e.g., the FSAR and NRC staff safety evaluations associated with various licensing actions), and can be appropriately controlled through the existing safety programs.

3. SONGS Independent Spent Fuel Storage Installation; Seismic Concerns

The City's August 12, 2016, letter raises concerns about the radiological safety impacts of spent fuel storage casks, specifically in regard to "storing spent fuel in a seismically active marine environment."[40] As explained below, the NRC staff has determined that the storage of spent fuel, in storage casks, at SONGS meets all applicable NRC safety criteria.

Reduction of SONGS License to the ISFSI

The NRC issued to SCE the SONGS operating licenses in accordance with its regulations in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." As a Part 50 license holder, SCE holds a general license to install and operate an "independent spent fuel

[40] City of Laguna Beach, Letter to C. Herzog, Senior Environmental Scientist, CSLC and M. Vaaler, Project Manager, NRC (August 12, 2016), at 3, n. 8.

storage installation" or ISFSI, on the SONGS site.[41] An ISFSI consists of a large concrete structure to safely store the spent fuel. The spent fuel assemblies are contained in the storage casks that are placed on or within the concrete structure of the ISFSI; the casks can consist of one or more cask designs, all of which must have been approved by the NRC.[42] The storage casks are passive systems; they are designed with one purpose, to safely store spent fuel. In addition to the concrete structure and storage casks, an ISFSI is typically fenced or otherwise secured as it is required to be located in a restricted access area.

The SONGS ISFSI is not included in the scope of the current SONGS decommissioning project and in all likelihood, will not be included in the LTP when submitted to the NRC. Thus, the aim of the current decommissioning process is to satisfy the requirements of 10 CFR 20.1402 for all areas of SONGS except the ISFSI. After the NRC approves the SONGS LTP, and SCE has completed the current decommissioning process and demonstrated its compliance with 10 CFR 20.1402, the NRC will amend SCE's Part 50 facility operating license such that the license will be reduced to an area that only encompasses the ISFSI facility. At that point, the only remaining licensee activities that are permitted and regulated by the NRC are those related to spent fuel storage and the eventual decommissioning of the ISFSI itself, once the spent fuel has been permanently removed from the ISFSI.[43]

ISFSI Design and Operation

During the period of ISFSI operation, the SONGS ISFSI will continue to be governed by the NRC's general license regulations for ISFSIs in Subpart K, "General License for Storage of Spent Fuel at Power Reactor Sites," of 10 CFR Part 72, ""Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater than Class C Waste." The NRC's regulations in 10 CFR Part 72 provide requirements for the safe design and operation of ISFSIs. Any operational conditions, required actions, monitoring or surveillance requirements, or other technical specifications that are needed for safe operation of the casks located at a general license ISFSI are included in the certificate of compliance that the NRC issues to the cask manufacturer. Section 72.212 requires licensees to comply with the terms, conditions, and specifications of the cask certificate.[44] In particular, the licensee must perform written evaluations before use of a given cask system that demonstrate that

> [c]ask storage pads and areas have been designed to adequately support the static and dynamic loads of the stored casks, considering potential amplification of earthquakes through soil-structure interaction, and soil liquefaction potential or other soil instability due to vibratory ground motion.[45]

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41 Under the applicable NRC regulations in 10 CFR Part 72, ""Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater than Class C Waste," the general ISFSI license is incident to the Part 50 license. The applicable regulation, 10 CFR 72.210, "General license issued," states that "[a] general license is hereby issued for the storage of spent fuel in an independent spent fuel storage installation at power reactor sites to persons authorized to possess or operate nuclear power reactors under 10 CFR part 50 or 10 CFR part 52." The conditions of the general ISFSI license are set forth in 10 CFR 72.212, "Conditions of general license issued under § 72.210."

42 10 CFR 72.212(b)(2)-(3); 10 CFR 72.214, "List of approved spent fuel storage casks."

43 As a general license ISFSI, the SONGS ISFSI will be decommissioned in accordance with 10 CFR 50.82.

44 10 CFR 72.212(b)(3).

45 10 CFR 72.212(b)(5)(ii) (alteration added).

Such written evaluations are subject to NRC inspection.

NRC regulations also require general ISFSI licensees to conduct radiation monitoring to ensure compliance with the NRC requirements for radiation dose limits for the public and ISFSI workers.[46] The NRC maintains oversight of ISFSIs, and the agency staff routinely inspects the site operations to ensure continued compliance with all applicable regulatory requirements, including the conditions and specifications of the applicable cask certificates.

In addition, the NRC requires aging management programs for spent fuel storage casks as storage operations continue into a renewed storage term.[47] Aging management programs include monitoring and inspections of both the ISFSI support structure and storage casks to detect any degradation, and corrective actions (such as further inspections, repairs or replacement of components, and other mitigation measures) to ensure that the ISFSI continues to meet the NRC's requirements for safe spent fuel storage. Licensees assess the effectiveness of these programs on an ongoing basis to determine if they need to be adjusted to address unexpected degradation, or degradation that may be occurring at a greater rate than was initially assumed. The NRC's oversight of ISFSIs includes inspection of a licensee's aging management activities.

Operating experience from the ISFSIs currently in operation is continually assessed by the licensees and the NRC to determine if new information, knowledge, and experience warrant any changes to licensed spent fuel storage operations. If a potential environmental impact (e.g., increased seismic activity) that could adversely affect the safe operation of the ISFSI is identified, the NRC will determine if the licensee will need to reevaluate its analyses and associated spent fuel storage operations to address the identified change.

Seismic Issues

In its development of the 2002 update to the Decommissioning GEIS, the NRC staff considered various site-specific issues at SONGS, including seismic risks. A draft was made available for public comment and one SONGS-specific comment was received. The comment stated,

> SONGS is located in a highly active seismic zone, where seismic activity is speculated by some geological experts to generate quakes up to 7.6 Magnitude on the Richter Scale (by new evidence of local off-shore blind thrust faults, which cause a greater extent of groundshaking and acceleration than the manner in which quakes are traditionally studied). SONGS was only designed and constructed to withstand a maximum quake of 7.0 Magnitude. SONGS is located in an area immediately on the southern California coastline, with most facilities elevated only to a level of 20 ft. above mean sea level. These facilities are highly exposed and vulnerable to effects of rising sea levels, and tsunamis, and are insufficiently protected.[48]

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46 10 CFR 72.104, "Criteria for radioactive materials in effluents and direct radiation from an ISFSI or [monitored retrieval storage] MRS;" 10 CFR 72.106, "Controlled area of an ISFSI or MRS." Both sections 72.104 and 72.106 are made applicable to general ISFSI licenses by operation of paragraph (c) of 10 CFR 72.13, "Applicability."

47 10 CFR 72.240, "Conditions for spent fuel storage cask renewal."

48 Decommissioning GEIS, NUREG-0586, App. O (2002) at O-124.

In response, the NRC replied,

> NRC staff recognizes that there is wide variability among nuclear power plants. However, based on the results of our analysis, the impacts resulting from decommissioning are similar regardless of plant characteristics, including site-specific information from San Onofre. The NRC established an envelope of environmental impacts resulting from decommissioning activities, identified those activities that can be bounded by a generic evaluation, and identified those that require a site-specific analysis. The NRC concentrated the environmental analysis on those activities with the greatest likelihood of having an environmental impact. Even for those impacts that have been determined to be generic, a licensee is required to do a site-specific analysis [in the PSDAR] to determine whether the impacts fall within the generic envelope. If they are outside of the bounds of the generic envelope, the licensee must seek approval from the NRC.[49]

The NRC is aware of no information, and the City has not provided any, that would invalidate the NRC's environmental and safety analyses, as set forth in the Decommissioning GEIS with respect to seismic activity or any other issue.

[49] *Id.*, at O-124 to O-125.

SUBJECT: ADDITIONAL INFORMATION REGARDING THE CALIFORNIA STATE LANDS COMMISSION RESPONSE TO THE CITY OF LAGUNA BEACH ENVIRONMENTAL REVIEW PUBLIC SCOPING COMMENTS FOR THE SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3, DECOMMISSIONING PROJECT dated September 5, 2018

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EXHIBIT 38

AUDIT REPORT

Audit of NRC's Compliance With 10 CFR Part 51 Relative to Environmental Impact Statements

OIG-13-A-20 August 20, 2013

All publicly available OIG reports (including this report) are accessible through NRC's Web site at:
http:/www.nrc.gov/reading-rm/doc-collections/insp-gen/

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICE OF THE
INSPECTOR GENERAL

August 20, 2013

MEMORANDUM TO: R. William Borchardt
Executive Director for Operations

FROM: Stephen D. Dingbaum **/RA/**
Assistant Inspector General for Audits

SUBJECT: AUDIT OF NRC'S COMPLIANCE WITH 10 CFR PART 51 RELATIVE TO ENVIRONMENTAL IMPACT STATEMENTS (OIG-13-A-20)

Attached is the Office of the Inspector General's (OIG) audit report titled, *Audit of NRC's Compliance With 10 CFR Part 51 Relative to Environmental Impact Statements.*

The report presents the results of the subject audit. The agency provided comments to the report on July 22, 2013. The agency's comments have been incorporated into the report at Appendix D.

Please provide information on actions taken or planned on each of the recommendations within 30 days of the date of this memorandum. Actions taken or planned are subject to OIG followup as stated in Management Directive 6.1.

We appreciate the cooperation extended to us by members of your staff during the audit. If you have any questions or comments about our report, please contact me at 415-5915 or Sherri Miotla, Team Leader, Nuclear Materials & Waste Safety Audit Team, at 415-5914.

Attachment: As stated

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EXECUTIVE SUMMARY

BACKGROUND

The National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA) established a national policy to encourage productive and enjoyable harmony between man and his environment, promote efforts that will prevent or eliminate damage to the environment, and enrich the understanding of ecological systems and natural resources important to the United States. To implement NEPA, Federal agencies must undertake an assessment of the environmental effects of their proposed actions prior to making a decision. The two major purposes of the NEPA process are better informed decisions and citizen involvement.

NEPA requires that Federal agencies prepare a detailed statement on the environmental impacts and effects, alternatives to the action, and irreversible commitments of resources involved in the action. This detailed statement is called an Environmental Impact Statement (EIS).

NRC's NEPA Role

The Nuclear Regulatory Commission's (NRC) regulations to implement NEPA are found in Title 10, Code of Federal Regulations, Part 51 (10 CFR Part 51). NRC's process for preparing an EIS begins when the agency receives an application for a proposed action that requires an EIS. A typical NRC environmental review includes analyses of impacts to specific resource areas, including air, water, animal life, natural resources, and property of historic, archeological, or architectural significance. In its NEPA review, NRC also evaluates cumulative, economic, social, cultural, and environmental justice impacts.

NRC's Commitments to the Public

The purposes of NEPA and its implementation dovetail with NRC's organizational values of openness and transparency, as expressed in the Principles of Good Regulation and the Strategic Plan. NRC activities generate a great deal of public interest. For their participation to be meaningful, stakeholders must have access to clear and understandable information about NRC's role, process, activities, and decisionmaking.

OBJECTIVE

The audit objective was to determine whether NRC complies with the regulations in 10 CFR Part 51 relative to the preparation of environmental impact statements.

RESULTS IN BRIEF

Areas of Current Noncompliance

In recent years, NRC has taken steps to enhance its NEPA reviews and procedures. These initiatives have generated important discussions and provide a context for long-term progress. However, the Office of the Inspector General (OIG) has identified areas of noncompliance with 10 CFR Part 51 relative to disclosure and public involvement. In order to clearly communicate the results of and involve the public in its environmental reviews, NRC management should strengthen its EIS preparation process by:

- Publishing a Record of Decision (ROD) that complies with 10 CFR 51.102 and 51.103.
- Publishing an EIS that complies with the format provided in 10 CFR Part 51, Appendix A.
- Performing all regulatory requirements for scoping for EISs that tier off of a generic EIS.

RECOMMENDATIONS

This report makes six recommendations to bring the agency into compliance with 10 CFR Part 51 relative to the preparation of EISs.

AGENCY COMMENTS

On July 22, 2013, NRC provided comments to the draft report. The agency stated its belief that its NEPA implementation activities have been fully compliant with the relevant regulations in 10 CFR Part 51. OIG's central message in the report is that through lack of compliance with NRC's NEPA-implementing regulations, the agency has made it difficult for stakeholders to access information developed in environmental reviews and may have omitted opportunities for public participation in certain environmental reviews. Appendix D contains NRC's comments

and Appendix E contains OIG's analysis of the agency's comments. The agency said it will consider OIG's recommendations as part of the agency's continuous improvement efforts because the recommendations could help enhance effectiveness, efficiency, and consistency across NRC programs in implementing NEPA.

ABBREVIATIONS AND ACRONYMS

ASLB	Atomic Safety and Licensing Board
ASLBP	Atomic Safety and Licensing Board Panel
CFR	Code of Federal Regulations
EIS	Environmental Impact Statement
FSME	Office of Federal and State Materials and Environmental Management Programs
NEPA	The National Environmental Policy Act of 1969
NMSS	Office of Nuclear Material Safety and Safeguards
NRO	Office of New Reactors
NRR	Office of Nuclear Reactor Regulation
NRC	Nuclear Regulatory Commission
OIG	Office of the Inspector General
ROD	Record of Decision

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I. BACKGROUND

The National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA) established a national policy to encourage productive and enjoyable harmony between man and his environment, promote efforts that will prevent or eliminate damage to the environment, and enrich the understanding of ecological systems and natural resources important to the United States. To implement NEPA, Federal agencies must undertake an assessment of the environmental effects of their proposed actions prior to making a decision. The two major purposes of the NEPA process are better informed decisions and citizen involvement.

NEPA requires that for a major Federal action significantly affecting the quality of the human environment, Federal agencies must prepare a detailed statement on the environmental impacts and effects, alternatives to the action, and irreversible commitments of resources involved in the action. This detailed statement is called an Environmental Impact Statement (EIS).

NEPA also established the White House Council on Environmental Quality to monitor and foster Federal agency compliance with NEPA. The Council on Environmental Quality promulgated regulations to ensure that agency procedures produce high quality environmental information, make that information available to the public and to agency decisionmakers, and ultimately to make "better decisions" as stated in NEPA. The Council on Environmental Quality regulations require Federal agencies to develop their own implementing procedures.[1]

NRC's NEPA Role

The Nuclear Regulatory Commission's (NRC) regulations to implement NEPA are found in Title 10, Code of Federal Regulations, Part 51 (10 CFR Part 51), "Environmental Protection Regulations for Domestic Licensing

[1] NRC revised its environmental regulations to meet the Council on Environmental Quality requirement to develop NEPA implementing procedures.

and Related Regulatory Functions." Part 51 identifies licensing actions that require the preparation of an EIS, including issuance of:

- An early site permit for a nuclear power reactor.
- A combined license to construct and operate a nuclear power reactor.
- A license renewal for an operating nuclear power reactor.
- A license to possess and use special nuclear material for processing and fuel fabrication or conversion of uranium hexafluoride.
- A license to possess and use source material for uranium milling or production of uranium hexafluoride.
- A license for a uranium enrichment facility.

NRC's process begins when the agency receives an application for a proposed action that requires an EIS. Once NRC considers the application complete and "accepts" it for review, an environmental review to comply with 10 CFR Part 51 and NEPA begins, paralleling the separate agency review for compliance with its technical or "safety" regulations. A typical NRC environmental review includes analyses of impacts to specific resource areas, including air, water, animal life, natural resources, and property of historic, archeological, or architectural significance. In its NEPA review, NRC also evaluates cumulative, economic, social, cultural, and environmental justice impacts.

The major steps in NRC's process for conducting this review and preparing the EIS are outlined in Appendix A of this report. Several steps provide opportunities for public involvement throughout preparation of the EIS. The Record of Decision (ROD) ties together the results of the environmental review and serves as an important vehicle for informing the public of the agency's conclusions and decision.

NRC's Commitments to the Public

The purposes of NEPA and its implementation dovetail with NRC's organizational values of openness and transparency, as expressed in the Principles of Good Regulation and the Strategic Plan.

Principles of Good Regulation

NRC has a longstanding goal of conducting its regulatory responsibilities in an open manner, and keeping the public informed of the agency's regulatory, licensing, and oversight activities. In pursuing its mission to protect public health and safety and the environment, NRC strives to adhere to the Principles of Good Regulation – independence, openness, efficiency, clarity, and reliability. More specifically, in the Principles, NRC says nuclear regulation is the public's business, and it must be transacted publicly and candidly. Furthermore, NRC commits that the public must be informed about and have the opportunity to participate in the regulatory process as required by law. Additionally, NRC states that open channels of communication must be maintained with Congress, other government agencies, licensees, and the public.

NRC's Strategic Plan 2008-2013

Ensuring appropriate openness explicitly recognizes that the public must be informed about, and have a reasonable opportunity to participate meaningfully in NRC's regulatory processes. NRC activities generate a great deal of public interest. For their participation to be meaningful, stakeholders must have access to clear and understandable information about NRC's role, processes, activities, and decisionmaking. In the Strategic Plan published in 2008, NRC adopted strategies to achieve openness goals, including:

- Communicating about NRC's role, processes, activities, and decisions in plain language that is clear and understandable to the public.

- Initiating early communication with stakeholders on issues of substantial interest.

When NRC updated its 2008-2013 Strategic Plan in 2012, the agency affirmed the importance of openness strategies to its effectiveness. The revised plan notes that "public stakeholders must have timely access to clear and understandable information." Further, the plan states that "participation allows members of the public to contribute ideas and expertise so that the NRC can make regulatory decisions with the benefit of information from a wide range of stakeholders."

II. OBJECTIVE

The audit objective was to determine whether NRC complies with the regulations in 10 CFR Part 51 relative to the preparation of environmental impact statements. Appendix B to this report contains information on the audit scope and methodology.

III. FINDINGS

In recent years, NRC has taken steps to enhance its NEPA reviews and procedures. For example, NRC has contracted to bring courses from the Duke University Environmental Leadership Program to NRC to develop a cadre of NEPA professionals in the agency. In addition, the agency's NEPA Executive Steering Committee was formed to identify common issues for NEPA implementation across NRC's program offices, including best practices and areas needing guidance. These initiatives have generated important discussions and provide a context for long-term progress. However, the Office of the Inspector General (OIG) has identified areas of noncompliance with 10 CFR Part 51 relative to disclosure and public involvement. In order to clearly communicate the results of and involve the public in its environmental reviews, NRC management should strengthen its EIS preparation process by:

- Publishing a ROD that complies with 10 CFR 51.102 and 51.103.

- Publishing an EIS that complies with the format provided in 10 CFR Part 51, Appendix A.

- Performing all regulatory requirements for scoping for EISs that tier off of a generic EIS.

A. Records of Decision Not in Full Compliance With Regulations

NRC offices with EIS preparation responsibilities do not publish a ROD that complies with the requirements in 10 CFR Part 51. NRC regulations provide specific criteria for the publication of a ROD and what must be included in a ROD. NRC does not publish a ROD that complies with its regulations because within the agency there are incorrect and varying interpretations of what the regulations require. Thus, NRC is not in compliance with its regulations. As a result, NRC (1) does not adequately notify the public, including Congress, Federal agencies, government partners and other stakeholders,[2] of its decision and the basis of that decision and (2) undermines its extensive efforts to be clear, open, and transparent.

NRC Regulations Require a Concise Public ROD

Any Commission decision for which an EIS is prepared must include or be accompanied by a ROD. A ROD is a document that explains NRC's decision, describes the alternatives considered, discusses potential environmental effects, and summarizes license conditions and monitoring programs adopted in connection with mitigation of environmental impacts. The ROD closes the NEPA process. 10 CFR 51.102 and 51.103 are the NRC regulations that require publication of a ROD and state what it must contain.

10 CFR 51.102

Section 51.102 specifies that for any action for which an EIS has been prepared, the EIS must include or be accompanied by a concise public ROD. If a hearing is held on the proposed action, the initial decision of the presiding officer will constitute the ROD. If the proposed action can only be taken by the Commissioners acting as a collegial body, the final

[2] Government partners include tribal governments, State governments, and local or municipal governments. Other stakeholders include public interest groups and any other interested member of the public.

decision of the Commission will constitute the ROD. The designated NRC staff director[3] is responsible for preparation of the ROD, except for instances when a hearing is held on the proposed action or the action is concluded as a result of a Commission decision.

10 CFR 51.103

Section 51.103 prescribes what all RODs must include, regardless of whether a hearing is held. Table 1 depicts these specifications.

Table 1. Requirements for a ROD

51.103(a): The ROD must be clearly identified and must:	
(1)	State the decision.
(2)	Identify all alternatives considered by the Commission in reaching the decision, state that these alternatives were included in the range of alternatives discussed in the EIS, and specify the alternative(s) which were considered to be environmentally preferable.
(3)	Discuss preferences among alternatives based on relevant factors, including economic and technical considerations where appropriate, NRC's statutory mission, and any other essential considerations of national policy, which were balanced by the Commission in making the decision and state how these considerations entered into the decision.
(4)	State whether the Commission has taken all practicable measures within its jurisdiction to avoid or minimize environmental harm from the alternative selected, and if not, to explain why those measures were not adopted. Summarize any license conditions and monitoring programs adopted in connection with mitigation measures.
(5)	In making a final decision on a license renewal action pursuant to Part 54 of this chapter, the Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decisionmakers would be unreasonable.

Source: 10 CFR 51.103(a)

[3] Section 51.4 defines the NRC staff director as the, (1) Executive Director for Operations, (2) Office of Nuclear Reactor Regulation (NRR) Director, (3) Office of New Reactors (NRO) Director, (4) Office of Nuclear Material Safety and Safeguards (NMSS) Director, (5) Office of Federal and State Materials and Environmental Management Programs (FSME) Director, (6) Office of Nuclear Regulatory Research Director, (7) Office of Governmental and Public Affairs Director, and (8) the designee of any NRC staff director.

51.103(b) and (c)

Additionally, a ROD meeting these requirements may be integrated into any other record prepared by NRC in connection with the action or may incorporate by reference material contained in the final EIS.

NRC Does Not Publish a ROD that Complies With the Regulations

For the sample of RODs provided by NRC and reviewed by OIG, NRC offices that prepare and publish EISs do not publish a ROD that complies with 10 CFR 51.102 and 51.103. OIG requested that NRC provide the RODs for 10 specific licensing actions. NRC responded to this request, providing documents that the offices asserted to be the ROD. See Appendix C for the specific licensing actions and OIG's methodology in selecting those actions.

The Documents Provided Are Not Concise

The documents provided by NRC are not concise as required by 10 CFR 51.102. For 4 of the 10 licensing actions, NRC provided multiple documents for each ROD. For example,

- For a fuel cycle facility, NRC provided (1) the 6-page materials license, (2) a 91-page decision from the Atomic Safety and Licensing Board (ASLB),[4] and (3) a 116-page decision from ASLB.[5]

- For another fuel cycle facility, NRC provided (1) the materials license, (2) the Federal Register Notice for the publication of the EIS, and (3) the Federal Register Notice for the publication of the Safety Evaluation Report.

- For each of the two Early Site Permits, NRC provided two documents: (1) a 100+ page ASLB decision and (2) a Commission Order.

[4] Decision Title: "First Partial Initial Decision (Uncontested/Mandatory Hearing on Safety Matters)" dated April 8, 2011.

[5] Decision Title: "Second and Final Partial Initial Decision (Uncontested/Mandatory Hearing on Environmental Matters)" dated October 7, 2011.

For an additional 4 of the 10 licensing actions, NRC provided a Federal Register Notice notifying the public that NRC had issued a license. The Federal Register Notices fail to state the required information, although they refer the reader to the EIS for "further information." However EISs are not concise. They are lengthy and complex documents, as depicted in Table 2.

Table 2. Length of EIS by Responsible Office

Responsible NRC Office	Range of Page Length of EIS
FSME	570 to 749 pages
NMSS	493 to 537 pages
NRO	504 to 919 pages
NRR	309 to 751 pages

Source: OIG analysis of NRC EISs in sample (See Appendix C)

Generally, the Documents Did Not Meet Regulatory Requirements for a ROD

Generally, the documents provided by NRC did not comply with the requirements of section 51.103(a), as depicted in Table 3. Table 3 represents OIG's analysis of the documents provided by NRC in response to OIG's request.

Table 3. Compliance With 51.103(a) Requirements by Office

Office	State the decision *51.103(a)(1)*	Identify alternatives *51.103(a)(2)*	Specify the environmentally preferred alternative *51.103(a)(2)*	Discuss preferences among alternatives *51.103(a)(3)*	State whether all practicable measures were taken to avoid environmental harm *51.103(a)(4)*	Summarize license conditions and monitoring programs *51.103(a)(4)*	Commission determination for license renewal[6] *51.103(a)(5)*
FSME	YES	YES[7]	NO	NO	NO	NO	N/A
NMSS	YES	NO	NO	NO	NO	NO	N/A
NRR	YES	YES[7]	NO	NO	NO	NO	NO
NRO	YES	NO[7]	NO	NO	NO	NO	N/A

Source: OIG analysis of documents provided by NRC for the sample of licensing actions (See Appendix C)

[6] 51.103(a)(5) states, "In making a final decision on a license renewal action pursuant to Part 54 of this Chapter, the Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decisionmakers would be unreasonable."

[7] 51.103(c) allows NRC to incorporate by reference material contained in the final EIS. Among documents sent to OIG in response to the request were Federal Register Notices from different offices. For two offices, FSME and NRR, the Federal Register Notices identified alternatives considered and refer to the EISs for further discussion. However, the NRO Federal Register Notices do not mention alternatives but only state where to locate documents associated with the licensing action, including the EIS.

NRC Offices Are Incorrectly Interpreting Regulations

NRC is not in compliance with 10 CFR 51.102 and 51.103 because the offices that publish EISs have varying and incorrect interpretations of the regulatory requirements. NRC managers gave varying responses as to what constitutes a ROD. For example, a senior manager advised OIG that "there is no such thing as a ROD in this [NRC] environment." Another senior manager said the ROD issue is an ongoing debate. Another senior manager said that the license, Safety Evaluation Report, and EIS constitute the ROD.

NRC staff also gave varying responses to what constitutes a ROD. For example, some FSME staff said that the Federal Register Notice is the ROD and others said the licenses or licensing documents are the ROD. An NRR staff member advised that the Federal Register Notice constitutes the ROD. Generally, NRO staff advised that the hearing or hearing decision constitutes the ROD. However, it is not clear, from staff responses, which document in the hearing record they consider to be the ROD. Additionally, another NRO staff member advised that the license is the ROD.

NRC Is Not in Compliance With Its Regulations

NRC is not in compliance with the requirements for publishing a ROD in sections 51.102 and 51.103. As a result, NRC does not adequately notify the public, including Congress, Federal agencies, government partners, and other stakeholders, of its decision and the basis for its decision.

A senior official from another Federal agency noted he looked for RODs in order to be more informed of the final decisions made by NRC, but found none. Another staff member of the same agency advised she could not find the information, for a specific licensing action, that should have been in a ROD.

Some members of the public were unable to identify NRC RODs and had difficulty with the information provided by NRC in lieu of a ROD. One stakeholder stated that NRC makes NEPA information available to the public by putting it on NRC's Web site. However, according to the stakeholder, the problem is there are voluminous amounts of data and it is

overwhelming to the average person. The information is not clear and concise, as required of a ROD. Another stakeholder opined that for a specific NRC licensing action that the stakeholder's group commented on, there was no ROD. This stakeholder informed OIG of reminding NRC that a ROD is required according to NRC's regulations. Another stakeholder said that NRC should summarize and simplify NEPA data so the average person can understand it. This stakeholder was experienced with NRC's Web site and understands environmental documents; however, this stakeholder opined, without a ROD the general public would have a difficult time understanding the data.

NRC does not publish a ROD that complies with its own regulations, and therefore does not adequately close the NEPA process. This fosters public skepticism that undermines the agency's extensive efforts to be clear, open, and transparent.

Recommendations

OIG recommends that the Executive Director for Operations:

1. Develop agencywide guidance for NRC staff to prepare and publish a concise public document that meets the requirements of 10 CFR 51.102 and 51.103.

2. Implement the agencywide guidance to ensure that all offices will consistently prepare and publish a concise public document that meets the requirements of 10 CFR 51.102 and 51.103.

B. NRC EISs Do Not Follow the Required Format

NRC's EISs do not follow the format described by 10 CFR Part 51, Appendix A. Appendix A to 10 CFR Part 51 identifies the format elements that must be included. NRC's EISs do not follow the Appendix A format because controls are not in place to assure use of that format. Thus, NRC is not in compliance with its regulations. As a result, NRC (1) does not clearly present, in an accessible way, the proposed action, alternatives, and conclusions to stakeholders and (2) undermines its extensive efforts to be clear, open, and transparent.

NRC Regulations Require a Specific Format

Appendix A to 10 CFR Part 51 prescribes a format that EISs "should" follow. The stated purpose of the standard format is to encourage good analysis and clear presentation of the alternatives, including the proposed action. The Appendix A format requires each EIS to have the following elements:

- *Summary*. The regulations require a summary that adequately and accurately summarizes the EIS. The purpose of a summary is to stress the major issues, discuss the areas of controversy, identify any remaining issues to be resolved, and present the major conclusions and recommendation.

- *Index.* The regulations require each EIS to have an index.

- *Cover Sheet*. The regulations require each EIS to have a cover sheet that includes the name, address, and telephone number of an individual at NRC who can provide further information. The cover sheet must also list the State, county, or municipality where the facility is located. Lastly, the cover sheet is not to exceed one page.

Appendix A allows a different format to be used, if there is a compelling reason to do so. However, if a different format is used, it "shall" include a summary, index, and cover sheet.

EIS Format Does Not Meet Regulatory Requirements

Based on OIG's sample, NRC's EISs do not follow the format required by 10 CFR Part 51, Appendix A, regarding a summary, index, and cover sheet. OIG reviewed a sample of 10 EISs prepared by NRC for 10 licensing actions. A list of those licensing actions and the methodology for OIG's sample selection is in Appendix C of this report. None of the 10 EISs reviewed fully met the Appendix A requirements for a summary or cover sheet. Only one of the EISs reviewed contained an index.

Summary

Each EIS contained an executive summary; however, none of the executive summaries adequately summarized the EIS or fully complied with the Appendix A requirements for a summary.

- For one office, the summaries did not stress the major issues considered, discuss areas of controversy, or identify any remaining issues to be considered.

- For another office, it is not clear whether the summaries stress the major issues considered,[8] and the summaries did not discuss the areas of controversy or identify any remaining issues to be considered.

- For another office, both summaries reviewed stressed major issues considered and one identified remaining issues to be considered. However, neither summary discussed areas of controversy.

Index

Of the 10 EISs reviewed, 9 lacked an index. The sole EIS that contained an index included key NEPA terms such as "alternatives," "mitigation," and "scoping" as well as a reference to Federal agencies such as the

[8] It is not clear whether these summaries stressed the major issues considered because the summaries included a summary of the environmental impacts for each resource area analyzed in the EIS. It is not apparent that each resource area is a major issue. Each resource area is required to be assessed in each EIS the office publishes.

Department of Energy and the Environmental Protection Agency and to State agencies.

Cover Sheet

While all of the EISs reviewed did have a cover sheet, none of the 10 EISs fully met the Appendix A requirements. Specifically:

- None of the cover sheets contained the name, address, and telephone number of an individual who could be contacted for further information.
- Four of the cover sheets did not contain the State, county, or municipality where the facility is located.
- None of the cover sheets contained the required information on a single page; instead, the information spanned three to five separate pages.

Controls Not in Place To Assure Proper Format

NRC EISs are not in compliance with the formatting requirements set forth in 10 CFR Part 51, Appendix A. Although NRC managers said they expect staff to follow the format prescribed in Appendix A, these managers are allowing EISs to be issued that are not properly formatted. The EISs are missing key components prescribed in Appendix A because controls assuring proper formatting are not in place. Although each NRC office that publishes an EIS has guidance that staff must follow to standardize environmental reviews, the "environmental standard review plans" instruct staff only to follow the Appendix A format. There is no clear, agencywide guidance to implement the requirements and thereby assure that EISs contain the key components.

Figure 1: NRC's most recent final EIS, published in four volumes.
Source: OIG

NRC Is Not in Compliance With Its Regulations

NRC is not in compliance with the format requirements for an EIS prescribed in 10 CFR Part 51, Appendix A. As a result, NRC is not presenting, in an accessible way, the proposed action, alternatives, major issues, controversies, remaining issues, and conclusions and recommendations to the public, including Congress, Federal agencies, government partners, and other stakeholders.

OIG interviewed stakeholders who provided public comments on EISs published by NRC. Generally, the stakeholders opined that information provided is not clear. One stakeholder, a former Federal Government employee familiar with looking at documents, stated that NRC's NEPA information is not clear or concise. This stakeholder further commented that reading and digesting the data provided by NRC is very difficult because the data is so voluminous. NRC ought to break down the information "in a common sense approach so the average person can do a quick read and learn how they may be impacted by the action," this stakeholder explained. Another stakeholder opined that some of NRC's EISs were long and complex and it was difficult for the stakeholder's organization to understand everything. As a result, this stakeholder's organization felt compelled to consult with other organizations to help them understand NRC's information. Another stakeholder opined that the way NRC reports information is difficult to understand. NRC provides a lot of technical information, but the meaning of the information is not obvious, added this stakeholder.

By not following the Appendix A format, NRC does not adequately present to the EIS reader the proposed action and alternatives considered by NRC. This inadequate presentation fosters public skepticism that undermines the agency's extensive efforts to be clear, open, and transparent.

Recommendations

OIG recommends that the Executive Director for Operations:

3. Develop agencywide guidance for NRC staff to comply with 10 CFR Part 51, Appendix A.

4. Implement the agencywide guidance to ensure that all EISs include all cover sheet information, a consistent summary format, and an index in compliance with 10 CFR Part 51, Appendix A.