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United States Nuclear Regulatory Commission

Protecting People and the Environment

NUREG-1437, Vol. 2
Supplement 45

Generic Environmental Impact Statement for License Renewal of Nuclear Plants

Supplement 45

Regarding Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2

Draft Report for Comment Appendices

Office of Nuclear Reactor Regulation

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Proposed Action	Issuance of renewed operating license NPF-57 for Hope Creek Generating Station and operating licenses DPR-70 and DPR-75 for Salem Nuclear Generating Station, Units 1 and 2 in Lower Alloway Creek Township, Salem County, New Jersey.
Type of Statement	Draft Supplemental Environmental Impact Statement
Agency Contact	Leslie Perkins U.S. Nuclear Regulatory Commission Office of Nuclear Reactor Regulation Mail Stop O-11F1 Washington, D.C. 20555-0001 Phone: 301-415-2375 Email: Leslie.Perkins@nrc.gov
Comments	Any interested party may submit comments on this supplemental environmental impact statement. Please specify NUREG-1437, Supplement 45, draft, in your comments. Comments must be received by December 17, 2010. Comments received after the expiration of the comment period will be considered if it is practical to do so, but assurance of consideration of late comments will not be given. Comments may be emailed to HopeCreekEIS@nrc.gov, SalemEIS@nrc.gov, or mailed to: Chief, Rulemaking, Directives, and Editing Branch U.S. Nuclear Regulatory Commission Mail Stop T6-D59 Washington, D.C. 20555-0001 Please be aware that any comments that you submit to the NRC will be considered a public record and entered into the Agencywide Documents Access and Management System (ADAMS). Do not provide information you would not want to be publicly available.

ABSTRACT

This draft supplemental environmental impact statement (SEIS) has been prepared in response to an application submitted by PSEG Nuclear, LLC (PSEG) to renew the operating licenses for Hope Creek Generating Station (HCGS) and Salem Nuclear Generating Station, Units 1 and 2 (Salem) for an additional 20 years.

This draft SEIS provides a preliminary analysis that evaluates the environmental impacts of the proposed action and alternatives to the proposed action. Alternatives considered include replacement power from a new supercritical coal-fired generation and natural gas combined-cycle generation plant; a combination of alternatives that includes natural gas combined-cycle generation, energy conservation/energy efficiency, and wind power; and not renewing the operating licenses (the no-action alternative).

The preliminary recommendation is that the Commission determined that the adverse environmental impacts of license renewal for Salem and HCGS are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable.

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Appendix A

Comments Received on the Environmental Review

A. Comments Received on the Environmental Review

A.1 Comments Received During Scoping

The scoping process began on October 23, 2009 with the publication of the Nuclear Regulatory Commission's (NRC's) Notice of Intent to conduct scoping in the *Federal Register* (74 FR 54859). The scoping process included two public meetings held at Salem County Emergency Services Building in Woodstown, New Jersey on November 5, 2009. Approximately 70 people attended the meetings. After the NRC staff delivered prepared statements pertaining to the license renewal process, the meetings were open for public comments. Attendees provided oral statements that were recorded and transcribed by a certified court reporter. Transcripts for the afternoon and evening meetings are available using the NRC's Agencywide Documents Access and Management System (ADAMS). The ADAMS Public Electronic Reading Room is accessible at http://www.nrc.gov/reading-rm/adams.html. Transcripts for the afternoon and evening meetings are available in ADAMS under Accession Nos. ML093240195 and ML100471177, respectively (NRC, 2009a; NRC, 2009b). Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS, should contact the NRC's Public Document Room reference staff by telephone at 800-397-4209 or 301-415-4737, or by e-mail at pdr.resource@nrc.gov. In addition to the comments received during the public meetings, comments were received through mail and email and were addressed by the staff.

Each commenter was given a unique identifier so that every comment could be traced back to its author. Table A-1 identifies the individuals who provided comments and the Commenter ID associated with each person's set of comments. To maintain consistency with the Scoping Summary Report (NRC, 2010), the unique identifier for each set of comments used in that report is retained in this appendix. The Scoping Summary Report also contains full text versions of all the comments received at the public meetings, in the mail, and through email.

Specific comments were categorized and consolidated by topic. Comments with similar specific objectives were combined to capture the common essential issues raised by participants. Comments fall into one of the following general groups:

- Specific comments that address environmental issues within the purview of the NRC environmental regulations related to license renewal. These comments address Category 1 (generic) issues, Category 2 (site-specific) issues, or issues not addressed in the GEIS or Category 2 (site-specific) issues. They also address alternatives to license renewal and related Federal actions.

- General comments that are (1) in support of or opposed to nuclear power or license renewal or (2) on the renewal process, the NRC's regulations, and the regulatory process. These comments may or may not be specifically related to this license renewal application.

- Comments that do not identify new information for the NRC to analyze as part of its environmental review.

- Comments that address issues that do not to fall within or are specifically excluded from the purview of NRC environmental regulations related to license renewal. These comments typically address issues such as the need for power, emergency preparedness, security, current operational safety issues, and safety issues related to operation during the renewal period.

Table A-1. Individuals Providing Comments during Scoping Comment Period

Commenter ID	Commenter Name	Affiliation (If Stated)	Comment Source
SHC-1	Lee Ware	Salem County Freeholders Board	Afternoon Scoping Meeting
SHC-2	Greg Gross	Delaware State Chamber of Commerce	Afternoon Scoping Meeting
SHC-3	Brian Duffey	Salem County Chamber of Commerce	Afternoon Scoping Meeting
SHC-4	Fred Stein	Delaware Riverkeeper Network	Afternoon Scoping Meeting, Written
SHC-5	Charles Hassler	IBEW Local Union 94	Afternoon and Evening Scoping Meetings
SHC-6	Carl Fricker	PSEG Nuclear, LLC	Afternoon and Evening Scoping Meetings
SHC-7	Dr. Peter Contini	Salem Community College	Afternoon Scoping Meeting
SHC-8	David Bailey Jr.	Ranch Hope, Inc	Afternoon Scoping Meeting
SHC-9	Kelly Wichman	PSEG Nuclear, LLC	Afternoon Scoping Meeting
SHC-10	Jane Nagaki	New Jersey Environmental Federation	Afternoon Scoping Meeting
SHC-11	Roland Wall	Center for Environmental Policy, Academy of Natural Sciences, Philadelphia	Afternoon Scoping Meeting
SHC-12	Julie Acton	Salem County Freeholder	Evening Scoping Meeting
SHC-13	Frieda Berryhill	Not stated	Evening Scoping Meeting
SHC-14	Nancy Willing	Not stated	Evening Scoping Meeting
SHC-15	Monica Beistline	Salem Generating Station	Evening Scoping Meeting
SHC-16	Fran Grenier	Woodstown Borough Councilman	Evening Scoping Meeting
SHC-17	Gina Carola	Sierra Club	Written Comments
SHC-18	John Greenhill	Not stated	Written Comments
SHC-19	Sidney Goodman	Not stated	Written Comments
SHC-20	William Dunn	Not stated	Written Comments
SHC-21	David Rickards	Instream Energy, LLC	Written Comments
SHC-22	Ellen Pompper	Lower Alloways Creek Township	Written Comments
SHC-23	Norm Cohen	The Unplug Salem Campaign	Written Comments

The comments received during the public meetings or as part of the scoping process are documented in this section, and the disposition of each comment is discussed thereafter. The formatting of the comment found in the source document in not necessarily maintained. Each comment has a unique identifier after the comment. For example, identifier SHC-20-2 corresponds to the second comment made by William Dunn, and identifier SCH-19-7 corresponds to the seventh comment made by Sidney Goodman.

The comments have been grouped by general categories. The categories are as follows:

1. Comments Concerning License Renewal and Its Processes
2. Comments in Support of License Renewal, PSEG, and Nuclear Power
3. Comments Concerning Aquatic Ecology and Related Issues
4. Comments Concerning Postulated Accidents
5. Comments Concerning Uranium Fuel Cycle and Waste Management
6. Comments Concerning Socioeconomics
7. Comments Concerning the Safety Issues and Aging Management of Plant Systems
8. Comments Concerning Alternatives to License Renewal
9. Comments Concerning Human Health
10. Comments Outside the Scope of License Renewal

To the extent practical, preparation of the draft Supplemental Environmental Impact Statement (SEIS) takes into account all the reasonable and relevant issues raised during the scoping process. The draft SEIS addresses both Category 1 and 2 issues, along with any new and significant information identified during the scoping process. The draft SEIS relies on conclusions supported by information in the Generic Environmental Impact Statement (GEIS; NRC, 1996; NRC, 1999) for Category 1 issues and includes the analysis of Category 2 issues, including any new and significant information identified.

A.1.1 Comments Concerning License Renewal and Its Processes

Comment: Now, you made a great deal about respecting public input. You had 20 license renewals approved now. None have been refused. I just wonder how much public input has really worked in these cases. None have been disapproved.

And some of them, by my estimate, should not have been approved. I have been to the NRC reading room in Washington, and there are records of every plant in there. Does Salem County have as complete a file as I would find it at the NRC reading room? Salem County library? Everything is in there? SHC-13-8

Comment: This letter concerns the proposed relicensing of Hope Creek. We oppose extending the license of this nuclear plant. We also oppose the process by which decisions on relicensing are made. This process makes it virtually impossible for most individuals and many organizations to participate. In addition, because only certain issues are deemed acceptable by the NRC for submission as contentions, many issues of safety and health are not even looked at by NRC in making their decision. We also oppose relicensing a nuclear plant twenty years before its license is up for renewal. SHC-23-1

Comment: However, it is important to put our concerns on the record, even though we do not expect NRC to act on any of them. SHC-23-3

Response: *The purpose and need for issuance of a renewed license is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, which may be determined by other energy-planning decision-makers. This definition of purpose and need reflects the Commission's recognition that a renewed license will be issued unless there are findings in the safety review or the National Environmental Policy Act (NEPA) environmental analysis that would lead the NRC to not grant a license renewal. The NRC does not have an energy-planning role in determining if a plant will be allowed to operate under the renewed license. If a renewed license is issued, energy-planning decision-makers and the applicant will ultimately decide whether a plant will continue to operate based on factors such as the need for power or other matters within the purview of the appropriate decision makers.*

The NRC has established an open process to permit all members of the public to participate in the environmental scoping process. The public is invited and encouraged to participate throughout the environmental review process. Input is specifically requested during the scoping period and during the draft SEIS review period. All comments received are evaluated and considered in the preparation of the draft and final SEIS. Finally members of the public and organizations are free to seek leave to intervene in the license renewal process and propose contentions within the scope of license renewal.

Copies of the license renewal applications and draft and final SEISs are made available for public review at the Commission's Public Document Room (One White Flint North, 11555 Rockville Pike, Rockville, MD 20852) as well as electronically on the NRC Web site at http://www.nrc.gov/reactors/operating/licensing/renewal/application.html, as they become available. The applications, as well as many of the supporting documents are also available from the NRC's ADAMS that is accessible from the NRC

ADAMS Web site at http://www.nrc.gov/reading-rm/adams.html. A copy of the applications for Salem Nuclear Generating Station (Salem)and Hope Creek Generating Station (HCGS), draft SEIS, and final SEIS are also available, or will be made available, at the Salem County Library.

These comments provide no new and significant information and will not be evaluated further in development of the SEIS.

Comment: If the NRC can give Oyster Creek a 20 year extension, even though that nuclear plant could not be built under today's standards, and is a meltdown waiting to happen, it is clear that the relicensing process for Hope Creek will be nothing more than paperwork and rubber stamping. SHC-23-2

Response: *The NRC performs a comprehensive review of each License Renewal application submitted. The NRC's review of each application for license renewal has four components: (1) a safety review,(2) an environmental review, (3) onsite inspections and audits, and (4) an independent review by the Advisory Committee on Reactor Safeguards (ACRS). The NRC staff performs a safety review of the information provided in the application, with additional* *information provided by the applicant at the NRC's request, and information elicited during audits and inspection. The results of the staff's safety review are documented in a publicly available safety evaluation report. The NRC staff's environmental review results in the publication of this document, a site-specific draft SEIS on license renewal. The public is invited to comment on the draft SEIS. Then, after considering all public comments, the NRC staff issues the final SEIS. Teams of inspectors with experience in nuclear plant safety visit the site and verify that the applicant has implemented its aging management plans as committed to in the application. The results of plant inspection(s) conducted as part of the license renewal process are made publicly available. The ACRS is an independent panel of experts that advises the Commission on matters related to nuclear safety. The ACRS reviews the applicant's application, the staff's safety evaluation report, and the results of the on-site audits and inspection(s) and makes its recommendation to the Commission regarding issuance of the renewed license. Only after all of these steps are satisfactorily completed will the NRC decide whether or not to renew a plant's operating license.*

This comment provides no new and significant information and will not be evaluated further in development of the SEIS.

A.1.2 Comments in Support of License Renewal, PSEG, and Nuclear Power

Comments: These comments can be located in Section A.2 with the alpha numeric comment identifiers: SHC-1-1, SHC-2-2, SHC-3-2, SHC-5-1, SHC-5-2, SHC-6-1, SHC-6-4, SHC-6-5, SHC-6-8, SHC-7-1, SHC-7-3, SHC-8-2, SHC-9-1, SHC-12-1, SHC-12-3, SHC-15-1, SHC-16-1, SHC-20-2, SHC-20-5, SHC-22-1

***Response**: These comments are general in nature and are primarily supportive of PSEG, nuclear power, and license renewal for Salem and HCGS. The comments provide no new and significant information and will not be evaluated further in development of the SEIS.*

A.1.3 Comments Concerning Aquatic Ecology and Related Issues

Comment: Speaking now directly to the environmental impact study, the Delaware Riverkeeper Network calls on the NRC and other reviewing agencies to hold the applicant to the highest scientific and regulatory standards as they prepare the EIS. Previous permits issued to PSE&G were based on data which were found to be faulty, misleading, biased and incomplete. In 1999 for instance, when PSE&G's permit came up for renewal, the company submitted over 150 volumes of information, data and arguments to support its case that it should be allowed to continue to kill Delaware River fish unimpeded.

Every year the Salem Nuclear Generating Station kills over 3 billion Delaware River fish including: Over 59 million Blueback Herring; Over 77 million Weakfish; Over 134 million Atlantic Croaker; Over 412 million White Perch; Over 448 million Striped Bass; and over 2 billion Bay Anchovy. Even NJDEP's own expert agrees that PSE&G assertions were not credible and were not backed by the data and studies PSE&G had presented. In fact according to ESSA consultants hired by NJDEP, PSE&G had greatly underestimated its impacts on Delaware River fish. According to ESSA, PSE&G "underestimates biomass lost from the ecosystem by perhaps greater than 2-fold." (ESA report p. xi) And "… the actual total biomass of fish lost to the ecosystem … is at least 2.2 times greater than that listed" by PSE&G. (ESSA Report p. 75)

ESSA Technologies' 154-page review of PSE&G's permit application documented ongoing problems with PSE&G assertions and findings including bias, misleading conclusions, data gaps, inaccuracies, and misrepresentations of their findings and damage. Some examples of ESSA's findings: With regards to fisheries data and population trends, ESSA said “The conclusions of the analyses generally overextend the data or results.” (p. ix); PSE&G “underestimates biomass lost from the ecosystem by perhaps greater than 2-fold.” (p. xi) “… the actual total biomass of fish lost to the ecosystem … is at least 2.2 times greater than that listed in the Application” (p. 75); “Inconsistency in the use of terminology, poorly defined terms, and a tendency to draw conclusions that are not supported by the information presented detract from the rigor of this section and raises skepticism about the results. In particular, there is a tendency to draw subjective and unsupported conclusions about the importance of Salem's impact on RIS finish species.” (p. 77); and Referring to PSE&G's discussion and presentation of entrainment mortality rates, ESSA found PSE&G's “discussion in the section of the Application to be misleading.” (p. 13).

The ESSA report contained no less than 51 recommendations for citations which PSE&G needed to take on its 2001 permit application before DEP made its decision, but that did not happen. It is our understanding that while NJDEP pursued some of these (which ones we do not know because it was not referenced in the draft permit documents) many of them were never addressed, and still others were turned into permit requirements to be dealt with over the next 5 years.

In addition to ESSA recommendations, NJDEP received comment from the State of Delaware and USF&W, both of whom conducted independent expert review of the permit application materials and found important problems with sampling, data, analyses and conclusions.

While we are urging you today to hold the applicant to high standards, I conclude by re-stating the fact that because Salem is clearly having an adverse environmental impact on the living resources of the Delaware Estuary and River, regardless of PSE&G's self-serving claims based on faulty scientific studies, the Clean Water Act requires “that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.” SHC-4-4; SHC-4-2

Comment: Not only that, but deceitful testimony has been given in support of the environmental impact of the existing nuclear plants. The statement for renewal states that the existing plants had no adverse effects on the Delaware Estuary. In fact, Salem kills 3 billion fish annually. Environmental expert Robert F. Kennedy Jr. sued the EPA in 1993. He revealed that Salem alone killed more than 3 billion Delaware River fish each year, according to the plant's own consultant. Fish kills are illegal and represent criminal acts. SHC-19-2

Response: *The comments are related to aquatic ecology and the quality and quantity of aquatic ecology data. As part of the staff’s environmental review and subsequent SEIS development, the data generated by the plant owners, as well as other available data, will be reviewed and assessed. The Staff’s evaluation of aquatic resources is presented in Chapters 2 and 4 (Sections 2.2.5 and 4.5, respectively) of the SEIS.*

Comment: [T]he Delaware Riverkeeper Network wants to reaffirm our long-standing position and call to convert the Salem Generating Station to closed-cycle cooling as mandated by Section 316(b) of the Clean Water Act. The Act states that generating plants such as Salem "shall be required that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." The application before the NRC does not call for the compliance of the Clean Water Act as it relates to best technology available. According to a study conducted by a NJDEP hired expert in 1989 as well as experiences at other facilities, installation of closed cycle cooling towers at Salem would reduce their fish kills by 95%. And dry cooling at Salem could reduce their fish kills by 99%. SHC-4-3; SHC-4-1

Comment: [T]he Environmental Federation is, also, very firmly committed to the idea that if the relicensing goes forward, on Salem 1 and 2, that best available technology should be applied at those plants, which would be cooling towers to offset the millions of gallons of water that cycle through that plant every day. There has been a lot of talk, today, about how nuclear energy produces no air emissions. And, generally, when we think about environmental impacts we are thinking air, releases to the air, releases to the water, and releases to the land. And while it is true that there may be no air emissions, from the plant, there certainly is a consumptive use of millions of gallons of water a day, run through the cooling cycle, and then discharged back into the Delaware Bay, with a concurrent loss, as Fred mentioned of billions of fish per year, in all stages of life, from larval stage, to small stage, to large scale fish that are impinged on the once-through cooling system, which I have toured, by the way, and witnessed the huge structure that takes through millions of gallons of water a day. So if there is one environmental issue that I would like to highlight today, is the impact of the Salem Nuclear Plant on water in the Delaware Bay, and the concurrent fish and wildlife that that water, the Delaware Bay supports. We talked about nuclear energy as being a major employer in this area, and I'm certainly respectful of the workers that work there, that keep the plant safe every day, and the niche in the economy that it provides. But there is, also, a huge other economy in the Delaware Bay that is the fishing industry, that is severely affected by the operation of this plant. And so if I were to say the huge, the most huge, environmental impact of this plant, is the impact of water, in that once through cooling system. That needs to be addressed in the environmental impact statement. SHC-10-1

Comment: Now, also, actually these plants were operating against the law, with more than three billion fish killed, annually, from the Delaware River; [and] anything under three inches is taken up through the intake structure. The NEPA Act, which you have mentioned, which was passed in 1969, was passed just because this kind of damage. On December 18th, 2001, Congress allowed these once-through cooling systems to continue as long as they restored the fish killed. SHC-13-5

Comment: Enclosed is a resolution, passed by the New Jersey Chapter of Sierra, requesting that the Nuclear Regulatory Commission and the New Jersey Department of Environmental Protection require PSE&G to erect cooling towers at the Salem Nuclear Plants as a requirement to renewing the operating licenses. The Executive Board of the New Jersey Chapter is making this request on behalf of over 20,000 members of the New Jersey Chapter. Thank you for your consideration in this very important matter. SHC-17-1

Comment: Every Power Plant currently using intakes, either for once through operations or to replenish water lost from evaporation, should be required to partner with the most local municipality and pipe their treated wastewater to the power plant to eliminate intakes.

Intakes kill millions of fish annually and once through operations adversely modifies the environment surrounding the outflow area. Municipalities need to dispose of their treated wastewater and to pipe this affluent to a facility that can use it is a least expensive and obviously the most environmentally friendly method.

All power plants should upgrade to a cooling tower technology. If too much heat in generated to recycle the water, cooling units can be added to the outflow troughs to reduce the temperature of the water prior to reuse.

The kinetic energy available in cooling tower outflows can be tapped with UEK turbine technology to generate enough electricity to run cooling coil units. ENERGY RECOVERED = GOOD MANAGEMENT. SHC-21-1

Response: *These comments relate to the impact on aquatic ecology associated with Salem's once-through cooling systems and call for the installation of cooling towers at Salem. The impacts of impingement and entrainment from Salem's once-through cooling system is discussed in Section 4.5 of the SEIS. However, with respect to the comments regarding mandating a closed-cycle cooling system at Salem, the New Jersey Department of Environmental Planning (NJDEP) Division of Water Quality is the regulatory authority that mandates alterations to a plant's cooling system. The NJDEP accomplishes this through its review and approval of the New Jersey Pollution Discharge Elimination System (NJPDES) permit for each facility. In 2006, PSEG submitted to the NJDEP an application for renewal of its 2001 NJPDES permit for Salem, which included a Section 316(b) determination under the Clean Water Act (33 U.S.C 1251 et seq.). Until that request is reviewed and approved by the NJDEP, the 2001 NJPDES remains in effect. In accordance with the 2001 NJPDES permit, PSEG has not been required to replace its once-through cooling system at Salem with cooling towers. (See Appendix B of PSEG, 2009 for Salem's 2001 NJPDES permit.)*

The staff's evaluation of Salem and HCGS's effect on aquatic ecology is discussed in Chapter 2 and 4 (Sections 2.2.5 and 4.5, respectively) of the SEIS.

Comment: This [Estuary Enhancement Program] involves ongoing restoration, enhancement, and preservation of more than 20,000 acres of degraded salt marsh, and adjacent uplands within the estuary.

The estuary enhancement program is the largest privately funded wetlands restoration project in the country. More importantly, it was created with extensive public participation, and open communication with regulatory agencies and the public.

As a result all the estuary enhancement program sites are open to the public, and offer boardwalks, nature trails, outdoor education, and classroom facilities.

Studies show that the overall health of the estuary continues to improve. In addition, analysis of long-term fish populations in the estuary show that, in most cases, the populations are stable or increasing.

And that fish population trends are similar through the other areas along the coast. We also recognize our important role and impact to the local community. SHC-6-2; SHC-6-6

Comment: So going back to another impact, and the result of the Salem 1 and 2 plants not having cooling towers is that PSEG Nuclear entered into a very large estuary enhancement program, which was referred to earlier, preserving 20,000 acres of wetlands. And I would be remiss if I didn't mention a concern that environmental groups raised at the beginning of the restoration project, because many of the acres of wetlands were restored simply by breaching dikes of old salt hay farms, and allowing inundation of phragmites by salt water. And thus controlling the phragmites and growing a more beneficial kind of vegetation, called Spartana. But there are acres and acres of phragmites, you know what they are, the tall waiving foxtails, as they are often called, which were considered nuisance vegetation, or not favorable vegetation in the wetland restoration. And so in order to control that phragmites, massive aerial herbicide event took place starting in 1995 and '96, over 2000 acres were really sprayed with a pesticide called Glyphesate. And it was thought that one, maybe two applications of that herbicide would take care of the problem. But, to this day, in the year 2009, and continuing on until at least 2013, annual applications by herbicide by aircraft are made to wetlands, as part of this project. The acreage is down now, to around 120 acre realm. But it has been as high as thousands of pounds of a year. And so one of the environmental issue raised by this is, is there going to be continued applications of an herbicide in wetland areas as part of this restoration project, which was meant to offset the impacts caused by the lack of cooling towers. The reason we are concerned about this application of herbicides is that it actually triggered an increase in the use of this herbicide, state-wide. PSEG kind of became the model for how to restore wetlands. And so many other wetland restoration projects began utilizing this methodology. And the result has been a nine-fold increase in the use of Glyphesate in the state of New Jersey. And so while the use at this particular Alloways creek area is decreasing, not over yet, but still decreasing, the increase in the use, state-wide, is of concern because as you know pesticides generally have a habit of infiltrating our groundwater and surface water. They become part of our drinking water, part of our surface water. And the effect of this herbicide has been linked to cancer effects, birth defect effects, effects on fish, insect populations, and so forth. So we certainly raise this as an issue that needs to be addressed, because nobody has really looked at the cumulative impact of this year after year application of herbicide to control a nuisance plant, all in the name of restoring wetlands. SHC-10-4

Comment: My comments today are based on observations of Academy scientists, particularly those of our senior fishery scientist, Dr. Rich Horowitz, who is unable to be here today. The estuary enhancement program began in 1994. And, since that time, [there] has been a large scale effort to restore and preserve portions of the Delaware estuary, in both New Jersey and Delaware, encompassing more than 32 square miles, as you heard earlier, it is the nation's largest privately-funded wetlands restoration project. Restoration efforts have included the goal of replacing former salt hay farms, as you heard. And also to remove marshes that are dominated by the invasive phragmites, with saltcord grass dominated marsh. This has required a substantial effort to control phragmites, and to change drainage patterns to foster topography and tidal flow typical of Delaware Bay salt marshes.

The Academy has studied many of these sites, prior to restoration and a number of them following restoration. Yes, the enhancement program has been successful in restoring typical salt marsh conditions at these sites, with most sites being targets for reduction of phragmites, and establishment of salt cordgrass. At the remainder of sites where goals have been partially met, the estuary enhancement program continues to work to further improve marsh conditions. The EP has also preserved open space, as at the bayside track. Among other improvements at the restored sites, tidal flow and development of tidal channels have increased, allowing for re-colonization of salt cordgrass and other species. The restored marshes support large numbers of targeted fish species, as well as number of other fishes and invertebrates. These populations continue to contribute to bay productivity, most notably, at the salt hay farms. The restoration sites also provide important habitat for terrapins, birds, and mammals, and several of the sites are now part of New Jersey's Audubon designated important bird areas. SHC-11-1

Comment: The basic restoration activities, particularly controlling phragmites and fostering development of tidal marsh topography and hydrology, have advanced the field of ecological restoration. The ecological engineering technique of forming primary channels, and then using estuarian processes to further develop channels and topography, is especially notable. And in that way the estuarian enhancement program does provide an important model for marshland restoration. PSEG has also installed fish passage structures at dams in Delaware and New Jersey. These fish ladders have established river herring spawning in nursery areas, and several impoundments, increasing bay-wide populations of these species. PSEG has continued to conduct monitoring programs of Delaware fish populations, which greatly increase our knowledge of Delaware Bay fisheries.

To conclude, the Academy would like to commend PSEG on its demonstrated initiative, and long-term commitment to restoring the critical wetlands of the Delaware estuary. The estuary enhancement program has had numerous positive impacts on the ecology and biodiversity of the region, and has made important contributions to the recreational and educational opportunities available to local communities. The scale and scope of this effort has supported large scale scientific research, has improved our understanding of the process of environmental restoration. The Academy of Natural Sciences has been pleased to have the opportunity to participate in, and to contribute, to our scientific expertise to this project. SHC-11-3

Comment: Now, I saw that you had a display back there about that Habitation Restoration Act of 2001. But are you really raising fish? Twenty-thousand tons of poison was spread to kill the phragmite. You can't kill that phragmite. I looked at the picture that you had back there, that phragmite keeps coming up. How many tons of poisons are you going to spray over there? Now, I was just told, a while ago, that you are replacing the fish. I would like to know how many fish that you are replacing, and what the story is on that. SHC-13-5

Response: *These comments address the estuary enhancement program currently being conducted by PSEG. The estuary enhancement program is a provision of the Salem's 2001 NJPDES permit. (See Appendix B of PSEG, 2009 for Salem's 2001 NJPDES permit.) The impacts of the estuary enhancement program will be discussed, as appropriate, in Chapter 4 (Section 4.5.5) of the SEIS.*

Comment: Hope Creek has leaked hydrazine into the Delaware Bay. SHC-23-4

Response: *There have been two recent hydrazine discharges at Salem reported to the NJDEP. These events are summarized below:*

In June of 2006, PSEG submitted a Discharge Confirmation Report to the NJDEP for the discharge of approximately 2000 gallons of water containing hydrazine and ammonium hydroxide from the Salem Unit 1 Condensate Polisher System to the ground, with an additional discharge of 2000 gallons to the Delaware River through a permitted outfall. The discharge, which occurred on May 10, 2006, was reported to the NJDEP hotline (case number 06-05-10-0235-20) and to the NRC. The source of the discharge was a lifted relief valve within the Salem Unit 1 Condensate Polisher Building. It was terminated immediately upon discovery. It was reported that 8.3 ounces, or 3 parts per million (ppm), of hydrazine was discharged to the

Delaware River and 8.3 ounces, or 3 ppm, was discharged to the ground without recovery. The Department issued a fine in the amount of $8250.00 which was paid in full. (NJDEP, 2009)

On June 25, 2007, PSEG submitted a Discharge Confirmation Report to the NJDEP for the release of approximately 20,000 gallons of water, containing hydrazine, from a catastrophic failure of the 24 Demineralizer Vessel sight glass in the condensate polisher system at Salem Unit 2. In this event, condensate water had discharged into the yard area east of the Salem Unit 2 Condensate Polisher Building. The discharge, which occurred on May 24, 2007, was reported to the NJDEP hotline (case number 07-05-24-0259-32) and to the NRC. The discharge to land was managed in accordance with PSEG Discharge Prevention, Containment, and Countermeasure Plan. Sampling and analyses were performed that demonstrated there was no discharge to surface water as a result of this event. (NJDEP, 2009)

To date, there has not been a reported discharge of Hydrazine into the Delaware Bay by HCGS. Minor chemical spills and their effect on water quality have been previously considered in the GEIS as a Category 1 issue. The NRC found the impact from these types of spills to be SMALL over the period of extended operations, as the effects are readily controlled through New Jersey's NJPDES permit process (as demonstrated above) and are not expected to have a significant impact on water quality. The comments do not provide new and significant information and will not be evaluated further in development of the SEIS.

A.1.4 Comments Concerning Postulated Accidents

Comment: What is unique about our community? What is unique about Artificial Island is that it is an island that was constructed of dredge spoil material. It is not an island that existed before the geology of the time. So one of the concerns, environmental concerns would be how stable is the structure of the island to support this plant for another 20 years. Or three plants, actually. I think that issue will be addressed, more specifically, tonight by another environmental group. What is the effect of sea level rise? We talked about global warming and how nuclear power doesn't produce the kinds of emissions that contribute to global warming. But there is global warming going on, and there is sea level rise. What is the effect of sea level rise on the plant's artificial island? You know, is the island going to be inundated with water, how much over the next few years? Does more infrastructures need to be built there to support the plant? We know that salt water and the effects of the salinity of the bay have contributed to the rusting out of parts of the plant. We know that there has been extensive replacement of structures, and underground piping at the plant. And that is both, you know, that is an environmental impact, the salinity of the area, on the integrity of the structure of the plant. And that is an environmental issue that needs to be integrated into the safety and the aging issues of the plant. SHC-10-3

Comment: I have been involved with Salem before it was licensed to operate, for the simple reason that Delmarva Power and Light, at the time, also planned to build a nuclear power plant right across the river from here, which would have made this area the largest nuclear complex in the world. I was an intervener, a case I couldn't lose, because they ordered a high temperature gas-cooled reactor, and you know what happened to that. I'm very concerned about this. I attended many hearings on the subject, ever since 1970. These plants should never have gotten a building permit. Upon examining the documents I found, to my shock, clearly described in detail, on the large map, the soil condition of Artificial Island.

You see, there was no land here. It is called Artificial Island, because the island is built from dredgings of the Delaware River. And in the documents you will find that the borings of 35 feet are essentially nothing but mud and sand. The next 35 feet are gravel and sand. The last 35 feet are described as Vincentown Formation, which is a different kind of gravel and sand. Borings up to 100 feet have not revealed rock bottom. There is no rock bottom under these plants. The spent fuel pools, the auxiliary buildings, all of it, is sitting perched on cement pilings, I call them stilts, going 75 feet into the mud. And that is what is holding these plants up. Now I have with me pictures of toppled buildings that have simply collapsed with the pilings still sticking to them. And I am deeply concerned to have a fourth reactor on that island. SHC-13-1

Comment: Liquefaction is discussed in the documents. Liquefaction is the phenomenon when there is an earthquake, not a major earthquake, the sand is liquefies, and the building -- the hundreds of examples all over the world, where you can find that. And you can find some of it even on Google. And I have made statements to that effect before the Delaware House Energy Committee, and other agencies. It doesn't seem to really matter what citizens say. Yes, there was an earthquake up in Morris County. It was, actually, quite sizeable. But there is an earthquake fault, also, on the Delaware River. And, really, it scares me to think that it is only a matter of time, really, that an earthquake could happen here. The Morris earthquake threw people out of the house; they thought there was a big explosion somewhere. It was not just a minor shaking or rattling. Now, as to what could happen, I would like to just go back to the Rasmussen report, which was produced in 1970, as to the safety of nuclear power plants. That wasn't satisfactory, so they commissioned another report in 1985, called “Consequences of Reactor Accident”, called the “[CRAC] Report”. To just -- the numbers are just staggering. The [CRAC] Report for Salem reads as follows: Early peak fatalities, 100,000 Salem, 100,000 Salem 2. Early peak injuries, 70,000 for Salem 1, 75,000 for Salem 2. Peak cancer deaths, Salem 1 40,000, Salem 2, 40,000. Damages, Salem 1, 140 billion, Salem 2, 135 billion. This is not fantasy, this is the government report. SHC-13-2

Comment: While speaking with the state official from the [New Jersey] Bureau of Nuclear Energy…., before the evaluation hearing had started I asked about having heard that Salem was built on swamp land. And the gentleman, whose name I don't have here, he said of course not, and he proceeded to claim that the pilings went on through the sand, and gravel on Artificial Island, and were drilled securely into the bedrock. So that was the opinion stated at that meeting, to me, by an official from the Bureau of Nuclear Energy here in New Jersey. So I took the question to the record, when I had a chance to speak, and formally ask the question, about Artificial Island structures, do they actually secure into bedrock, or don’t they? Because Frieda Berryhill had told me that in her investigations, that they had not. So I asked, for the record, and the officials promised me that they would investigate that discrepancy, and give it back to me in writing, which they never did, I never got anything from them.

My concern was based on having heard that yet one more unit was planned to be constructed at the Salem complex. For the structures to be floating on a bed of gravel, and sand, and the result of a significant earthquake, six or seven on the Richter scale, would mean that the base of the structures, containing this nuclear material, would likely experience liquefaction, which Frieda got into a little bit.

That is the changing from compression of the earthquake, of the gravel and sand mix, into a jelly-like material. Liquefaction of the ground underneath causes structures to tip, slide, collapse, and otherwise break apart. It was an unhappy coincidence that the evacuation hearing was on the same day as the earthquake. So it was an interesting experience. Another earthquake was centered a few miles away from the Salem plant. And although it wasn't more than maybe two on the Richter scale, I'm not sure what it was, it isn't unheard of to think that we would have a more significant earthquake. The officials told me, that day, that the structures are built to withstand up to six or so on the Richter scale. But would that prevent a significant earthquake, maybe not up to that, would that prevent the leaks and cracks of an aging plant that is floating on a bed of gravel and sand, so to speak, should another earthquake occur. So the scope of the licensing process, here today, I think should be investigating that these are drilled into bed rock, that they are subject to liquefaction, and that would the aging of structures, brittle…would the aging, basically, have an impact on potential earthquake activity and contamination of the environment? And I think that is, hopefully that would be in your scope, some serious study of that. SHC-14-3

Comment: To renew the license for these nuclear plants represents extreme neglect of the public safety and welfare. It was incredibly poor judgment that these plants were built on "Artificial Island" in the first place. These plants should be shut down, with operation not allowed to continue, much less have their operation greatly extended. Incredibly, PSE&G is considering putting another nuclear plant on this island in this earthquake prone region. None of the nuclear plants are built on solid rock. They are filled in land. The letter I received from Bruce A. Boger (August 24) confirmed that these plants are not on solid rock. They rest on compacted engineering fill material or concrete, which have a depth of approximately 70 feet. Concrete pilings are used. The NRC presumes that this will enable them to resist the worst assault that an earthquake can deliver. SHC-19-1

Comment: What can happen from building on unstable land was exemplified in Shanghai, China. At around 5:30 AM on June 27, 2009 an unoccupied building, still under construction at Lianhuanan Road in the Mining district of Shanghai City toppled. Just before toppling, there were reports of cracks on the flood-prevention wall near the buildings and "special geological conditions" in the water bank area. In Japan, seven reactors at the Kashiwasz-Kariwa nuclear power plant in Japan were shut down due to an earthquake, fire and nuclear leak. People were killed and injured by the 6.8 magnitude earthquake, which struck in July, 2007. A new fire at the still shut down plant occurred in March, 2009. 600,000 residents signed a petition opposing restart of the plant. The arrogance of building nuclear plants in an earthquake prone area is almost unbelievable. Believe it! This arrogance is also invested in the other Nuclear Regulatory Commission rules. SHC-19-3

Comment: Hope Creek is vulnerable to a severe earthquake because Artificial Island is built on compacted mud, and its pilings do not reach bedrock. SHC-23-6

Response: *These comments address the formation and stability of the land on which Salem and HCGS are built and the susceptibility of the area to natural disasters such as earthquakes and a resulting liquefaction scenario.*

The potential for liquefaction was previously evaluated by the NRC in NUREG-1048, "Safety Evaluation Report Related to the Operation of Hope Creek Generating Station" (NRC, 1984). The report concluded that the river bottom sand will be stable under safe shutdown earthquake conditions that the plant is designed to withstand. In addition, issues related to the impacts of *natural disasters on the plant and the plant's ability to continue operating under its current license are addressed on an ongoing basis as part of the NRC's day-to-day oversight process.*

With respect to the commenter's concern regarding calculations from the CRAC report, the NRC has devoted considerable research resources, both in the past and currently, to evaluating accidents and the possible public consequences of severe reactor accidents. The NRC's most recent studies have confirmed that early research into the topic led to extremely conservative consequence analyses that generate invalid results for attempting to quantify the possible effects of very unlikely severe accidents. In particular, these previous studies did not reflect current plant design, operation, accident management strategies or security enhancements. They often used unnecessarily conservative estimates or assumptions concerning possible damage to the reactor core, the possible radioactive contamination that could be released, and possible failures of the reactor vessel and containment buildings. These previous studies also failed to realistically model the effect of emergency preparedness. The NRC staff is currently pursuing a new state-of-the-art assessment of possible severe accidents as part of its ongoing effort to evaluate the consequences of such accidents.

These comments do not provide new and significant information and will not be evaluated further in development of the SEIS.

Comment: I am unable to attend the hearings on 11/15/09 but would like to submit the following questions. There were incidents on 03/13/1989 and 9/19/1989 at the Salem 1 and 2 Nuclear Plants sites when geomagnetic storms caused damage to the single phase, generator step-up transformers which caused them to be taken out of service. The damages were due to geomagnetically induced currents caused by the geomagnetic storms.

Questions:

1. Is there a publically available report that describes these incidents?
2. What was the magnitude of the currents that caused the damage?
3. How long did the damaging currents persist?
4. What was the protective relay system in place at that time such as the IEEE Std C37.91 1985?
5. Where there any modifications to the transformer protective system put into effect?
6. How will the step-up transformers at Salem and hope Creek sites be protected if a super geomagnetic storm (10 times the size of the 1989 storms) occurs during the 20 year extension?
7. Do the sites have spare step-up transformers?

An initial cursory look shows a possible problem with the draft EIS when one examines table 5-2. The probability of a super solar storm of the 1859 or 1921 size is about 1/100 years or 1 % year. This size storm leads to a continental long term (many months) grid outage because of damage to all the U.S. step-up transformers similar to the damage that occurred at Salem New Jersey in 1989 during a fairly mild solar storm. With such an outage the emergency generators (that drive the cooling pumps) fuel supply would run out and could not be replaced because the commercial fuel suppliers would be out of fuel as well. Without fuel for the cooling pumps, the core damage frequency (CDF) appears to be several orders larger that the CDF given in the table 5-2. Perhaps a solar storm initiating event should be included in all the final EIS documents including the Salem and Hope Creek. SHC-18-1; SHC-18-2; SHC-18-3

Response: *The seven questions listed in the comment above have been provided to the appropriate NRC Region I staff and a separate response was provided to the commenter. These questions raise concerns that are related to current operational issues at the plant but do not fall within the scope of the license renewal environmental review and, therefore, will not be evaluated in development of the SEIS.*

With respect to the comment's suggestion that solar storms should be included as an initiating event for severe accident mitigation alternatives (SAMA), the staff considers the issue as follows: The SAMA analysis considers potential ways to further reduce the risk from severe reactor accidents in a cost-beneficial manner. The process for identifying and evaluating potential plant enhancements involves use of the latest plant-specific, peer-reviewed probabilistic risk assessment (PRA) study. These risk assessment studies typically show that loss of offsite power (LOSP) and station blackout (SBO) sequences are among the dominant contributors to core damage frequency (CDF) for nuclear power plants and account for about 20 to 50 percent of the CDF. As a result, enhancements to mitigate SBO events initiated by a LOSP are routinely identified and evaluated in the SAMA analysis. Consideration of SBO events initiated by a solar storm would not be expected to result in identification of additional SAMAs to mitigate LOSP and SBO events since license renewal applicants already perform a search for potential means to mitigate these risk contributors.

Consideration of solar storms would not be expected to substantially impact the CDF for LOSP/SBO events because postulated damage to generator step-up transformers would not affect the operation of the emergency diesel generators (EDGs). The EDGs would function to cool the reactor core until connections to the electrical grid are reestablished or alternative means of core cooling are established. Onsite fuel storage is typically sufficient to provide for at least 7 days of EDG operation and would be replenished during this period, as demonstrated at the Turkey Point plant following Hurricane Andrew in 1992 (NRC, 1992). Even with a major disruption in the supply chain, the 7-day period is sufficient for alternative arrangements to be made to resupply fuel for nuclear power plant EDGs in accordance with the National Response Framework (see National Response Framework, Emergency Support Function #12 – Energy Annex, www.fema.gov/pdf/emergency/nrf/nrf-esf-12.pdf). Alternative means of core cooling would be viable in the longer term, given that core cooling requirements (e.g., required pumped flow rates) would be substantially reduced days and weeks after reactor shutdown, and given the substantial industry and Federal resources that would be available to facilitate these measures.

If there is incompleteness in current PRAs with respect to an underestimate of the frequency or consequence of solar storm-initiated LOSP/SBO events, the sensitivity analysis performed on the SAMA benefit calculation would capture the increased benefit that might result from a more explicit consideration of solar storm-induced events. This analysis typically involves increasing the estimated benefits for all SAMAs by an uncertainty multiplier of approximately 2 to determine whether any additional SAMA(s) would become cost-beneficial and retaining any such SAMA(s) for possible implementation. In summary, the consideration of solar storm-initiated events would not be expected to alter the results of the SAMA analysis since *enhancements that address these types of events are already considered in the applicants' search for SAMAs to mitigate SBO/LOSP events, and any potential underestimate of the benefit of these SAMAs would be captured in existing applications by the use of the uncertainty multiplier on the SAMA benefits.*

A.1.5 Comments Concerning Uranium Fuel Cycle and Waste Management

Comment: Has the company made any request for dry-cask storage? …With Yucca Mountain canceled you will have to, eventually, go the dry cask storage, I just want to know how soon, or whether you have made any plans, and who is producing them. You don't know that? SHC-13-7

Comment: Because Yucca Mountain, the national depository for spent nuclear fuel, will not be operative, Lower Alloways Creek will become, and actually is now, a long term nuclear waste dump, which violates the zoning board agreement between PSEG and Lower Alloways. SHC-23-7

Response: *The safety and environmental effects of long-term storage of spent fuel onsite have been assessed by the NRC, and, as set forth in its Waste Confidence Decision (codified at 10 CFR 51.23), the Commission generically determined that such storage could be accomplished without significant environmental impact. In the Waste Confidence Decision, the Commission determined that spent fuel can be stored onsite for at least 30 years beyond the license operating life, which may include the term of a renewed license. At or before the end of that period, the fuel would be removed to a permanent repository. In its Statement of Consideration for the 1990 update of the Waste Confidence Decision (55 FR 38472), the Commission addressed the impacts of both license renewal and potential new reactors. In its December 6, 1999, review of the Waste Confidence Decision (64 FR 68005), the Commission reaffirmed the findings in the rule. In addition to the conclusion regarding safe onsite storage of spent fuel, the Commission states in the rule that there is reasonable assurance that at least one geologic repository will be available within the first quarter of the 21st century, and sufficient repository capacity for the spent fuel will be available within 30 years beyond the licensed life for operation of any reactor. Accordingly under 10 CFR 51.23(b), no site-specific discussion of any environmental impact of spent fuel storage in reactor facility storage pools or ISFSIs is required in an environmental impact statement associated with license renewal. These comments do not provide new and significant information and will not be evaluated further in development of the SEIS.*

Comment: As far as, there is no radiation produced at this plant, there is some radiation produced at this plant. It meets limits, so called acceptable limits. There is waste that is stored on-site. And so another environmental issue, that the environmental impact statement should address, is how much more waste is going to be generated and stored at the plant, at those enclosures that currently keep all the waste, ever produced at that plant, on the site forever. So, waste production concurrent with the relicensing is another very major environmental issue. SHC-10-2

Comment: Third, based on my research on the emerging nuclear fusion technology, the disposal of nuclear waste will one day be safely transmuted to useful isotopes. Nuclear fusion and fission will be paired to provide almost unlimited power without the issue of residual radioactivity. SHC-20-3

Response: *The GEIS considered a variety of spent fuel and waste storage scenarios, including onsite storage of these materials for up to 30 years following expiration of the operating license, transfer of these materials to a different plant, and transfer of these materials to an ISFSI. For each potential scenario, the GEIS determined that existing regulatory requirements, operating practices, and radiological monitoring programs were sufficient to ensure that impacts resulting from spent fuel and waste storage practices would be SMALL, and therefore, were a Category 1 issue. These comments do not provide new and significant information and will not be evaluated further in development of the SEIS.*

A.1.6 Comments Concerning Socioeconomics

Comment: I didn't realize that we have about in excess of three hundred employees, from Delaware, that come across that bridge each day. But it is not just about the 300 folks that come across that bridge, it is also about the families they support. SHC-2-1

Comment: Approximately 400 businesses and community organizations are members of the Salem County Chamber of Commerce, and this includes PSEG Nuclear, who is a long-time member.

On behalf of the Chamber, I would like the NRC to know that PSEG Nuclear plays a leading role in our community. They have supported the Chamber's efforts to build relationships, within the community, and to make Salem County a premier place to live, work, and conduct business.

They purchase goods and services from dozens of local businesses, and Chamber members, and with our support they are helping to drive the local economy.

Earlier this year PSEG Nuclear, hosted the Chamber Board of Directors for a tour of the Salem and Hope Creek facilities. It became very clear, to the Board of Directors that PSEG operates in a culture of safety and security.

That visit also reinforced the Board's belief that PSEG Nuclear operations provide a safe and clean source of energy. We also believe that nuclear power can help to combat climate change, and that PSEG's operations will continue to play a positive role in Salem County's future.

Without these plants hundreds of people would be left without jobs, dozens of local businesses would struggle, and our local economy would suffer a great loss. SHC-3-1

Comment: As such we have looked to partner with local communities, with our local community, to meet our needs to providing good paying local jobs. We have launched innovative partnerships with the Salem County Community College, and the Salem County Vocational Technical schools, to develop specialized training programs.

Both have been overwhelmingly successful, and will lead to a skilled workforce that will only strengthen the local economy. In Salem County we provide more than 1.4 million dollars, each year, to the local economy through local property taxes.

This funding is vital to supporting local schools and projects. From an economic development point of view, we have also helped to drive the local economic development through projects like revitalization of downtown Salem, and the construction of the Gateway Business Park in Oldmans Township.

We are also active partners in the Salem Main Street Program, and the Salem County Chamber of Commerce. Our support also goes well beyond dollars. Many of our employees are active participants and supporters within the local community. SHC-6-3; SHC-6-7

Comment: Their support is not just verbal. Their support is certainly implementing. And as you know, and you heard Carl say, there is going to be a growing need for employees, as certainly portions of the workforce ages out, and we hope, also, the expansion of opportunity in the future.

As a result we work collaboratively with PSE&G Nuclear, in focusing on a particular area that we think is of great need, an energy, nuclear energy technician position.

We were able to couple with them, and partner at the national level with the Nuclear Energy Institute. And we were selected as one of six community colleges, across the country, that are working on standardizing the curriculum to ensure that educational experience that our students have, will not only prepare them, but certainly ensure safety and security in the future in this field.

And you also heard about the center that has been revitalized in Salem City. Well, I'm proud to tell you that a portion of that center will be hosting a portion of our program.

And through a high tech classroom, as well as laboratory facilities, our students will be working with state of the art equipment. And, most importantly, be supportive both in scholarships, as well as internships.

So we see this as a real win-win. Thinking about this, that we have only, in less than one year, been able to implement this program, we now have a fully accredited nuclear energy technician program, technology program, what we refer to as NET, we now have over 50 students in that program.

The corresponding program, Sustainable Energy, is also working at about 20 students. We see that balance, and PSE&G Nuclear sees that balance, also. And they have been very collaborative in working with Energy Freedom Pioneers, as we look for other alternatives to energy in addition to nuclear.

These are important things, they are important things for our community and, certainly, for our students. But they also go beyond. Two years ago we had an emergency in our Salem center, hosting our one-stop career center. A fire, a fire that immediately caused the dislocation of over 30 workers, and 200 clients a day.

Within two hours we had a commitment from PSE&G Nuclear to relocate that entire program to the former training center. And within two days we were fully operational for the next four months. SHC-7-2

Comment: Ranch Hope, Inc., is a 501c(3) non-profit organization, founded in 1964. Again, our Alloway headquarters are within minutes of the Salem and Hope Creek facilities. Our mission is to provide behavioral health care, educational, and adventure-based environments for children and families from throughout the state of New Jersey, and within the Delaware Valley.

Through its generosity and support of local organizations, such as Ranch Hope, PSE&G Nuclear has touched the lives of thousands of residents, making our community a better place to live.

At Ranch Hope's Alloway campus PSE&G Nuclear supports our efforts to create a green community for children with treatment and educational facilities, not only environmental responsible, but energy efficient, and healthy for children and staff to live and work.

This unique collaboration with PSEG Nuclear not only focuses on changing the lives of children and families, but also energy efficiency, two topics you don't normally see together. SHC-8-1

Comment: In addition to ecological restoration, the enhancement program has developed increased opportunities for human use and experience, to interact with the estuary.

Public use areas were designed to meet the general education, public access, and ecotourism interest of each community hosting an EEP site.

This has included improved access to many of the sites by land and water, with boat access and parking areas, in turn, supporting extensive recreational activities.

The public use areas have become important settings for numerous formal and informal educational programs. The restored areas have also become significant research sites, and research by EEP, and other organizations, including the Academy, has advanced our knowledge of tidal marsh ecology. SHC-11-2

Comment: Not only are they a great community partner, but they are the county's largest employer. A majority of their employees are local residents, who live in our community.

In tough economic times PSEG Nuclear provides an example of integrity and commitment to positive growth that we all need to see.

PSEG Nuclear takes a very proactive role in developing positive relationships with members of the Salem County community, whether it is providing funding and support to local community groups, or attending their events. SHC-12-2

Response: *These comments, in general, are supportive of the applicant and also address the socioeconomic benefits of Salem and HCGS on local/regional communities and economy, including other related issues such as employment, taxes, education, and philanthropy. The staff addresses the socioeconomic impact of renewing the Salem and HCGS operating licenses in Chapter 2 and 4 (Sections 2.2.8 and 4.9, respectively) of the SEIS. In addition, the socioeconomic impact of not renewing the operating licenses of these generating stations is discussed in Chapter 8.*

A.1.7 Comments Concerning Safety Issues and Aging Management of Plant Systems

Comment: But I do want to say that some of the safety concerns, and environmental concerns, are related mainly to this issue of the aging of the plant, the salinity, the lack of a firm under-structure to the plant, all make the plant more vulnerable to failures of structure that could lead to an environmental release of radiation, which is the ultimate disaster that everybody fears at this plant. And so while the radiation leakage issue, and emissions issue, is not a day to day concern, you know, when the plant is operating optimally, if there isn't an aggressive strategy for preventive maintenance, that not just waits for something to happen, and then addresses it, but actually anticipates and replaces structures as they age, before they age. This vulnerability will continue, you know, to be of great concern. SHC-10-5

Comment: Clearly this plant should have never received a building permit, and surely it should not receive a license to operate for another 20 years. They were originally licensed for 40 years. You are dealing with embrittlement, and all sorts of problems with that. There was a reason for it. SHC-13-4

Comment: I don't agree with the renewal of the 20 year licenses for the 40 year old structures that exist here today. I don't think it is a wise and reasonable choice for the citizens. We do enjoy the energy that comes out of them, but we also have to expect to live our full lives here in this area. A 40 year life span pretty much says it all, it is a 40 year life span, and the thought of another 20 year service from the Salem and Hope Creek structures seems to be asking too much, and offering uncertainty and trepidation to the public. With age come leaks and cracks. The life span of potential contamination isn't worth that bargain, in my view. SHC-14-2

Comment: The environmental impact appears to be minimal for granting an extension of the facilities license and there is certainly a justified need to upgrade portions of nuclear power generating operations to replace aging equipment that will improve the power generating capabilities and mitigate safety issues of an aging plant. SHC-20-1

Comment: The electrical system that connects Hope Creek to the grid is old and has had a number of failures, including transformer failures.

PSEG has a spotty record when it comes to keeping diesel generators working. This is a concern because all three nuclear plants rely on diesel generators if offsite power is interrupted.

PSEG has a serious Safety Conscious Work Environment (SCWE) and Safety Culture problem. This has been a chronic problem at all 3 of PSEG's plants, and continues to show up in NRC inspections under “cross-cutting issues of human performance.” One key example at Hope Creek was the loss of 5000 gallons of cooling water, due to human error. This event could have escalated into a TMI-type of situation. SHC-23-5

Comment: Hope Creek has buried pipes and electrical conduits that have not been inspected and, based on other nuclear plants, may be leaking tritium or in danger of electrical shorts happening. SHC-23-8

Response: *NEPA focuses on the environmental impacts of a major Federal action (such as license renewal) rather than on issues related to the safety of an operation. Safety issues become important to the environmental review when they could result in environmental impacts, which is why the environmental effects of postulated accidents will be considered in the SEIS. Because the Council on Environmental Quality (CEQ) regulations implementing NEPA do not include a safety review, the NRC has codified regulations for conducting an environmental impact statement separate from the regulations for reviewing safety issues during its review of a license renewal application. The regulations governing the environmental review are contained in 10 CFR Part 51, and the regulations covering the safety review, including the aging management issues discussed in most of these comments, are contained in 10 CFR Part 54. For this reason, the license renewal review process includes an environmental review that is distinct and separate from the safety review. Because the two reviews are separate, operational safety issues and safety issues related to aging are considered outside the scope for the environmental review, just as the environmental issues are not considered as part of the safety review.*

With respect to the safety aspect of such systems and components being able to operate for another 20 years, the staff makes that determination as part of its license renewal safety review, which focuses on the programs and processes that are designed to ensure adequate protection of the public health and safety during the 20-year license renewal period through management of aging components. As part of the license renewal safety review, PSEG Nuclear, LCC is required to demonstrate that the effects of aging will be adequately managed. For example, regarding buried piping, NRC staff performing the safety review are incorporating recent industry operating experience into aging management programs proposed by the applicant.

These comments are not within the scope of the license renewal environmental review and will not be evaluated further in development of the SEIS.

A.1.8 Comments Concerning Alternatives to License Renewal

Comment: Fourth, the option of purchasing more electricity by decommissioning these facilities will likely require modifying and building additional transmission lines to support this option. This will have a far more deleterious effect on the environment and communities where these lines will be constructed that continuing to operating these nuclear facilities. Furthermore, importing electricity will likely originate from either coal or gas fired units that produced the greenhouse gases CO2 (and other pollutants) as compared to nuclear power that generates zero greenhouse gas. SHC-20-4

Comment*:* Hope Creek should be decommissioned at the end of its 40 year license. Affected employees should be relocated and retrained by PSEG. Artificial Island should be turned into a wind power and solar power "park" to produce some of the electrical energy formerly produced by the nuclear plants. SHC-23-12

Response: *These comments refer to the alternatives to license renewal, including the alternative of not renewing the operating licenses for Salem and HCGS, also known as the "no-action" alternative. The staff has evaluated all reasonable alternatives in Chapter 8 of the SEIS.*

A.1.9 Comments Concerning Human Health

Comment: Hope Creek emits continual amounts of low level radiation and radionuclides, which contribute to the cancer cases and immune system disorders in the 50 mile zone around Artificial Island. SHC-23-10

Response: *Although radiation may cause cancers at high doses, currently there are no reputable scientifically conclusive data that unequivocally establish the occurrence of cancer following exposure to low doses, below about 10 roentgen equivalent man (rem; 0.1 sievert [Sv]). However, radiation protection experts conservatively assume that any amount of radiation may pose some risk of causing cancer or a severe hereditary effect and that the risk is higher for higher radiation exposures. Therefore, a linear, no-threshold dose response relationship is used to describe the relationship between radiation dose and detriments, such as cancer induction. Simply stated, any increase in dose, no matter how small, results in an incremental increase in health risk. This theory is accepted by the NRC as a conservative model for estimating health risks from radiation exposure, recognizing that the model probably over-estimates those risks. Based on this theory, the NRC conservatively establishes limits for radioactive effluents and radiation exposures for workers and members of the public. While the* *public dose limit in 10 CFR Part 20 is 100 millirem (mrem; 1 millisievert [mSv]) for all facilities licensed by the NRC, the NRC has imposed additional constraints on nuclear power reactors. Each nuclear power reactor, including Salem and HCGS, has enforceable license conditions that limit the cumulative annual whole body dose to a member of the public from all radioactive emissions in the offsite environment to 25 mrem (0.25 mSv). In addition, there are license conditions to further limit the dose to a member of the public from radioactive gaseous effluents to an annual dose of 5 mrem (0.05 mSv) to the whole body and 15 mrem (0.15 mSv) to any organ. For radioactive liquid effluents, the dose standard is 3 mrem (0.03 mSv) to the whole body and 10 mrem (0.1 mSv) to any organ.*

Nuclear power reactors were licensed with the knowledge that they would release radioactive materials into the environment. NRC regulations require that the radioactive material released from nuclear power facilities be controlled, monitored, and reported in publically available documents. The amount of radioactive effluents released into the environment is known to be small. The radiation exposure received by members of the public from commercial nuclear power reactors is so low (i.e., less than a few mrem) that resulting cancers attributed to the radiation have not been observed and would not be expected. To put this in perspective, each person in this country receives a total annual dose of about 300 mrem (3 mSv) from natural sources of radiation (e.g., 200 mrem from naturally occurring radon, 27 mrem from cosmic rays, 28 mrem from soil and rocks, and 39 mrem from radiation within our body) and about 63 mrem (0.63 mSv) from man-made sources (e.g., 39 mrem from medical x-rays, 14 mrem from nuclear medicine, 10 mrem from consumer products, 0.9 mrem from occupations, less than 1 mrem from the nuclear fuel cycle, and less than 1 mrem from fallout due to weapons testing).

Although a number of studies of cancer incidence in the vicinity of nuclear power facilities have been conducted, there are no studies to date that are accepted by the scientific community showing a correlation between radiation dose from nuclear power facilities and cancer incidence in the general public. The following is a listing of studies recognized by the Staff:

- *In 1990, at the request of Congress, the National Cancer Institute (NCI) conducted a study of cancer mortality rates around 52 nuclear power plants and 10 other nuclear facilities. The study covered the period from 1950 to 1984 and evaluated the change in mortality rates before and during facility operations. The study concluded there was no evidence that nuclear facilities may be linked causally with excess deaths from leukemia or from other cancers in populations living nearby (NCI, 1990).*

- *In June 2000, investigators from the University of Pittsburgh found no link between radiation released during the 1979 accident at the Three Mile Island power plant and cancer deaths among nearby residents. Their study followed 32,000 people who lived within 5 miles of the plant at the time of the accident (Talbot et al., 2003).*

- *The Connecticut Academy of Sciences and Engineering, in January 2001, issued a report on a study around the Haddam Neck nuclear power plant in Connecticut and concluded radiation emissions were so low as to be negligible and found no meaningful associations to the cancers studied (CASE, 2001).*

- *Also in 2001, the Florida Bureau of Environmental Epidemiology reviewed claims that there are striking increases in cancer rates in southeastern Florida counties caused by increased radiation exposures from nuclear power plants. However, using the same* *data to reconstruct the calculations, on which the claims were based, Florida officials were not able to identify unusually high rates of cancers in these counties compared with the rest of the State of Florida and the nation (Bureau of Environmental Epidemiology, 2001).*

- *In 2000, the Illinois Public Health Department compared childhood cancer statistics for counties with nuclear power plants to similar counties without nuclear plants and found no statistically significant difference (Illinois Public Department of Health, 2000).*
- *The American Cancer Society in 2004 concluded that although reports about cancer clusters in some communities have raised public concern, studies show that clusters do not occur more often near nuclear plants than they do by chance elsewhere in the population. Likewise, there is no evidence that links strontium-90 with increases in breast cancer, prostate cancer, or childhood cancer rates. Radiation emissions from nuclear power plants are closely controlled and involve negligible levels of exposure for nearby communities (ACS, 2004).*

In April 2010, the NRC asked the National Academy of Sciences (NAS) to perform a state-of-the-art study on cancer risk for populations surrounding nuclear power facilities. The NAS study will update the 1990 U.S. National Institutes of Health - NCI report, "Cancer in Populations Living Near Nuclear Facilities" (NCI, 1990). The study is expected to be completed within 4 years. Information from the report will be considered for incorporation into future updates of the NRC's guidance and regulations, as appropriate.

To ensure that U.S. nuclear power plants are operated safely, the NRC licenses the nuclear power plants to operate, licenses the plant operators, and establishes license conditions for the safe operation of each plant. The NRC provides continuous oversight of plants through its Reactor Oversight Process to verify that they are being operated in accordance with NRC regulations. The NRC has full authority to take whatever action is necessary to protect public health and safety and the environment and may demand immediate licensee actions, up to and including a plant shutdown.

The impact on human health of renewing the operating licenses for Salem and HCGS will be evaluated in Section 4.8 of the SEIS.

A.1.10 Comments Outside the Scope of License Renewal

Comment: I was at the 2009 emergency evacuation public hearing, here in New Jersey. And it was an interesting meeting for me because although Delaware is at risk, or in the 50 mile radius, we don't get this kind of attention, we don't have public hearings. And I imagine that -- I was told, as I got here today, that some feelers went out to see if Delaware wanted to have a meeting similar to this, and it was not -- that didn't happen. But that the emergency evacuation public meeting the state held, I didn't -- well, I will just go right to this. SHC-14-1

Comment: The NRC is still satisfied with a mere ten-mile evacuation zone around a nuke when poisons from Three Mile Island were blown hundreds of miles. Poisons from Chernobyl were blown around the world? … The NRC continues support for the Price Anderson Act. This federal law limits liability of a disaster to a microscopic fraction of the potential damage which will be incurred? The act reduces concerns of operating utilities, a very risky effect. This federal law abolishes the property rights of Americans in order to protect the property rights of nuclear plant owners. This atrociously unfair law is nothing less than fascist. The NRC continues to support the distribution of potassium iodide pills as an assurance that no one will be harmed from a disaster? These pills only protect against radioactive iodine. The pills must be taken immediately and continue to be used for as long as radioactive iodine lingers in the environment. The pills do nothing to project against all of the other radioactive poisons, which are released. This is no real assurance to anyone who is informed. The NRC continues to support ridiculously inadequate evacuation plans following a fuming meltdown at a nuke. SHC-19-4

Comments: The Evacuation Plan for Salem/Hope Creek is based on faulty assumptions and would not work under many scenarios, including a fast acting radiation release and multiple releases. Under worst case scenarios, thousands of people within the 10 and 50 mile zones would die from radiation exposure. SHC-23-9

Response: *Emergency planning is not within the scope of the license renewal as set forth in 10 CFR Parts 51 and 54, as it is addressed as a current licensing issue on an ongoing basis. The NRC has regulatory requirements in place under 10 CFR Part 50 to ensure that licensees have adequate emergency planning and evacuation programs in place in case of an accident/emergency scenario. Such plans are evaluated by the NRC and coordinated with the Federal Emergency Management Agency (FEMA) and local authorities for implementation. Drills and exercises are conducted periodically to verify the adequacy of the plans. Issues identified during such exercises are resolved within the context of the current operating license and are not reevaluated as part of license renewal.*

In addition, the Commission issued a Final Rule on potassium iodide (KI) in the Federal Register on January 19, 2001 (66 FR 5427). The NRC does not require use of KI by the general public because the NRC believes that current emergency planning and protective measures (i.e., evacuation and sheltering) are adequate and protective of public health and safety. However, the NRC recognizes the supplemental value of KI and the prerogative of the states to decide the appropriateness of the use of KI by its citizens. At this time, the NRC has made KI available to States that wish to include thyroid prophylaxis in their range of public protective actions to be implemented in the event of a serious accident at a nuclear power plant that would be accompanied by a release of radioactive iodine. Both New Jersey and Delaware have programs for issuing the KI pills. The KI pills are for the individuals living within the 10-mile emergency planning zone (EPZ). In addition, schools and emergency workers also have a cache of pills in case of an emergency.

These comments are not within the scope of this environmental review and will not be evaluated further in development of the SEIS.

Comment: I would like to interject, recently I wrote an article as to the soil conditions of this thing. And in that article I mentioned the Price-Anderson Act, that nuclear power plants could never be built without the protection of the Price-Anderson Act. And some gentleman from the NRC felt compelled to write an answer to the local Wilmington paper saying, we don't depend on the Price-Anderson Act, we have 9 billion dollars in reserve for whatever damages we cause.

It makes me laugh, because there is no comparison to the damages that could be caused. Nine billion dollars is pocket change. SHC-13-3

Comment: Incredibly, though, that PSEG announced that it planned to spend another 50 million between 2007 and 2011 to explore the potential to construct a new reactor on the island, a fourth reactor. I think not. I would like to ask a few questions, if I may. Nine billion dollars somewhere in the reserve? Can anybody, at the NRC, tell me who is holding this nine billion dollars? I have a letter written to the editor, don't worry about Price-Anderson, we have nine billion dollars. Who would have that nine billion? Well, I will see if I can find out another way. SHC-13-6

Response: *The Price-Anderson Nuclear Industries Indemnity Act (Price-Anderson Act; 42 U.S.C. 2210) is a federal law that governs liability-related issues for all non-military nuclear facilities constructed in the United States before 2026. The main purpose of the Act is to partially indemnify the nuclear industry against liability claims arising from nuclear incidents while still ensuring compensation coverage for the general public. The Act establishes a no fault insurance-type system in which the first $10 billion is industry-funded and any claims above the $10 billion would be covered by the Federal government.*

Licensees are required by the Act to obtain the maximum amount of insurance against nuclear-related incidents that is available in the insurance market. Currently this insurance amount is approximately $375 million per plant. Monetary claims that fall within this insurance coverage are paid by the insurer. The Price-Anderson fund would then be used to make up the difference. Each reactor company is obliged to contribute up to $111.9 million in the event of an accident, amounting to approximately $11 billion if all of the reactor companies were required to pay their full obligation into the fund. However, this fund is not paid into unless an accident occurs.

If a coverable incident occurs, the NRC is required to submit a report on the cost of the incident. if claims are likely to exceed the maximum Price-Anderson fund value, the President must submit a proposal to Congress that details the costs of the accident, recommends how funds would be raised, and includes plans for compensation to those affected.

These comments regarding the Price-Anderson Act and the commenter’s opinion regarding allocation of funds are not within the scope of this environmental review and will not be evaluated further in the development of the SEIS.

Comment: Hope Creek remains a prime terrorist target, and there are many ways terrorists could prevail, only one of which will I list here.

Hope Creek's Spent Fuel Pool is above ground and not protected by containment.

It is a prime terrorist’s target. If the water in the Pool drains out, there would be massive radiation releases. SHC-23-11

Response: *The NRC and other Federal agencies have heightened vigilance and implemented initiatives to evaluate and respond to possible threats posed by terrorists, including the use of aircraft against commercial nuclear power facilities and spent fuel storage installations. The NRC routinely assesses threats and other information provided by other Federal agencies and sources. The NRC also ensures that licensees meet appropriate security-level requirements. The NRC will continue to focus on prevention of terrorist acts for all nuclear facilities and will not focus on site-specific evaluations of speculative environmental impacts resulting from terrorist acts. While these are legitimate matters of concern, they will continue to be addressed through* *the ongoing regulatory process as a current and generic regulatory issue that affects all nuclear facilities and many of the activities conducted at nuclear facilities. The issue of security and risk from malevolent acts at nuclear power facilities is not unique to facilities that have requested a renewal to their licenses because these issues are being addressed on an ongoing basis for all nuclear facilities.*

With respect to the commenter's concern regarding the spent fuel pool (SFP) accident, previous studies show that the risk associated with spent fuel pool accidents and dry cask storage accidents is considerably less than that for reactor accidents (e.g., NUREG-1738 and NUREG-1864). Further, additional mitigation strategies implemented subsequent to September 11, 2001, further reduce the risk from SFP fires by enhancing spent fuel coolability and the ability to recover SFP water level and cooling prior to a potential SFP fire.

These comments are not within the scope of this environmental review and will not be evaluated further in development of the SEIS.

A.2 Full Text Versions of the Scoping Comments

The following pages contain full text versions of the scoping comments received at the public meetings, in the mail, and via email along with their accompanying identifiers.

MR. WARE: Thank you, Lance. My name is Lee Ware, Director of Salem County Freeholders Board, starting my tenth year as a Freeholder. I'm a little down today because my beloved Phillies went down.

And I guess it is only appropriate, since I was a baseball coach, for 38 years, I will be the lead-off hitter here today, Lance.

I'm coming before you, today, to let you know that PSEG Nuclear is a valuable asset to our county. Not only are they great community partners, but they are the county's largest employer.

They have been good neighbors, and good partners. A majority of their employees are local residents, who live in our community. PSEG takes a very proactive role in developing positive relationships with members of Salem County community.

Whether it is providing funding and support to local community groups, or attending every community event. A lot of members here can attest to that. We see each other quite a bit.

They are always demonstrating their commitment to Salem County's proud heritage and bright future. We understand

SHC-1-1

the hesitation of those within and surrounding our county, towards PSEG Nuclear.

Their concerns regarding safety, and plant performance, are valid. However, PSEG Nuclear has consistently demonstrated its commitment to safety, and excellence, through proper planning and transparency.

As life-long residents of Salem County, six miles as the crow flies from the reactors, I feel safe around the power plant, I have raised my children here, and they still reside here.

We have seen no negative impact to our environment, or community. I support PSEG Nuclear and license renewal for the Salem and Hope Creek stations. Their continued success is our success. Thank you.

SHC-1-1

MR. GROSS: Good afternoon. I'm Greg Gross, I'm director of government affairs with the Delaware State Chamber of Commerce, and we represent about 1,700 plus members of the business and corporate communities in the Delaware, throughout Delaware.

And when I was invited, and I want to thank you for the opportunity to come here and speak in support of one of our most valued partners. And, quite frankly, when I was invited to come speak in support, I knew about it, I wasn't totally educated about it, but I took a few minutes yesterday, and educated myself about what it means to the Delaware community.

I didn't realize that we have about in excess of three hundred employees, from Delaware, that come across that bridge each day. But it is not just about the 300 folks that come across that bridge, it is also about the families they support.

SHC-2-1

About the economic structure in our community that it supports. And also, too, I took a few minutes to query a few of our elected officials that are very involved, and plugged into the environmental community and said, you know what, Greg? We don't worry about them, we don't worry, because they are safe, because they have gone that extra mile to be safe.

SHC-2-2

If there is something there that they know may be troublesome, they address it before it happens. So that means something. I said, we don't worry.

There always will be, I'm sure, apprehensions to what goes on, and there always will be fear, I'm sure. But as each year goes by I'm sure that that fear will slowly dissipate as things often do, with such things of this nature.

But we are happy that we do have such a strong partner involved in every facet of our community in Delaware. As I said, I didn't realize how much, until I went back and I looked over some things.

SHC-2-2

And I was saying, wow, I mean it is just incredible what a strong partner. And when you are going down the years of 2016, I think the other one was 2026, I don't know if I will be around in 2026.

I'm hoping I will be around in 2026. But I hope that I am, and I hope I am back even more educated, and being able to speak more passionately about what I believe is the great work that is done.

And, most importantly, the safety and just preparing for what we are going to be facing in the years, as far as what we are going to need for our energy, and our needs. It doesn't get any easier.

And, Lord knows, the need doesn't get any smaller, it gets even larger. So with that said, you know, we give our total support in any way we possibly can, whether we -- whether in a letter, from our President, or any folks that are needed, within our community there, please don't hesitate to let us know.

Thank you, again, for allowing me to take a few minutes of your time to be here with you today, and I look forward to hearing additional comments, thank you.

SHC-2-2

MR. DUFFEY: Good afternoon. I'm the current vice-chair, and the 2010 incoming chair of the Salem County Chamber of Commerce.

Approximately 400 businesses and community organizations are members of the Salem County Chamber of Commerce, and this includes PSEG Nuclear, who is a long-time member.

On behalf of the Chamber, I would like the NRC to know that PSEG Nuclear plays a leading role in our community. They have supported the Chamber's efforts to build relationships, within the community, and to make Salem County a premier place to live, work, and conduct business.

They purchase goods and services from dozens of local businesses, and Chamber members, and with our support they are helping to drive the local economy.

SHC-3-1

Earlier this year PSEG Nuclear, hosted the Chamber Board of Directors for a tour of the Salem and Hope Creek facilities. It became very clear, to the Board of Directors that PSEG operates in a culture of safety and security.

That visit also reinforced the Board's belief that PSEG Nuclear operations provide a safe and clean source of energy. We also believe that nuclear power can help to combat climate change, and that PSEG's operations will continue to play a positive role in Salem County's future. SHC-3-1

Without these plants hundreds of people would be left without jobs, dozens of local businesses would struggle, and our local economy would suffer a great loss.

The Salem County Chamber of Commerce supports PSEG Nuclear, and its plans for license renewal, for an additional 20 years of operation for Salem and Hope Creek. Thank you for your time. SHC-3-2

MR. STEIN: Thank you very much. My name is Fred Stein, I work with the Delaware Riverkeeper Network, it is a non-profit environmental advocacy organization.

I would like to thank the NRC for the opportunity to speak to the license renewal application submitted by PSEG and Exelon. We understand the purpose of today's meeting, of the dual meetings, today, is to discuss the process around the license renewal and the requisite EIS scoping.

And I will speak directly to that. But, first, the Delaware Riverkeeper Network wants to reaffirm our long-standing position, and call to convert the Salem generating station to a closed cycle cooling system, as mandated by the Section 316(b) of the Clean Water Act.

The Act states that generating plants, such as Salem, shall be required that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing the adverse environmental impacts. SHC-4-1

The application before the NRC does not call for the compliance of the Clean Water Act, as it relates to the best technology available. And it should.

According to our study, conducted by New Jersey DEP hired expert in 1989, as well as experiences at other facilities, installations of a closed cycle cooling towers, at Salem, would reduce the fish kills from the Delaware river by 95 percent.

And dry cooling systems, at Salem, would reduce it even further, to 99 percent.

SHC-4-1

Speaking now, directly to the Environmental Impact Study, the Delaware Riverkeeper Network calls on NRC, and other reviewing agencies, to hold the Applicant to the highest scientific and regulatory standards as they prepare the EIS.

Previous permits issued to PSEG were based on data that were found to be faulty, misleading, biased, and incomplete. In 1999, for instance, when the data and arguments to support its case, that it should be allowed to continue to kill the Delaware River fish unimpeded.

Every year the Salem Nuclear Power Plant kills over three billion fish in the Delaware River. That includes over 59 million blue-backed herring, 77 million weak fish, over 134 million arctic croakers, over 412 million white perch, over 448 million striped bass, and over 2 billion bay anchovies.

Even DEP's own experts agree that PSEG's assertions were not credible, and were not backed by the data and studies

SHC-4-2

PSEG had presented. In fact, according to an ESSA Consultant hired by New Jersey DEP, PSEG had greatly underestimated its impact on the Delaware river fish resources.

According to ESSA, PSEG underestimated biomass loss from the ecosystem by, perhaps, as many as two-fold. And the actual total biomass of fish loss to the ecosystem is at least 2.2 times greater than was listed by PSE&G.

ESSA technologies' 154 page review of PSE&G's permit application, documented ongoing problems with PSE&G's assertions and findings, including biased, misleading conclusions, data gaps, inaccuracies and misrepresentation of their findings and damage.

Some of the examples of the EESA findings were with regards to the fisheries data and population trends, ESSA said the conclusions of the analysis generally overextended the data or results.

PSE&G underestimated biomass loss from the ecosystem by, perhaps, as many as two-fold. Inconsistency in the use of terminology, poorly defined terms and tendency to draw conclusions that are not supported by the information presented detract from the rigor of this section and raises skepticism about the results.

SHC-4-2

In particular there is a tendency to draw subjective and unsupported conclusions about the importance of Salem's impact on the fish species in the river.

And, finally, referring to PSE&G's discussions, and presentations of entrainment, mortality rates, ESSA found PSE&G's discussion in this section of the application, to be misleading.

The ESSA report contained no less than 51 recommendations for actions which PSE&G needed to take, on its 2001 permit application before DEP. But that didn't happen, none of those happened.

It is our understanding that while DEP pursued some of these, many of them were never addressed, and still others were turned into permanent requirements to deal with over the next permit cycle.

In addition to ESSA recommendations, New Jersey DEP received comment from the State of Delaware, and the U.S. Fish and Wildlife Services, both of whom conducted independent expert review of the permit application materials.

And found important problems with sampling, data analysis, and conclusions. While we are urging you today, NRC, while we are urging you today to hold PSE&G as they go through this EIS process, to the highest standards, I want to reinforce

SHC-4-2

our belief that I started my comment with, that -- I'm sorry, I jumped ahead.

I conclude by restating the fact that because Salem is clearly having an adverse environmental impact on the living resources of the Delaware river, and estuary, regarding PSE&G, we encourage you to hold them to the highest standards possible. I'm sorry, I lost my place here.

We feel that it is important that, through the EIS process, that the data that PSE&G and its consultants bring to you, is complete, and unbiased, and that it is thoroughly looked at by the NRC, and it will be by the general public, too.

SHC-4-2

In a Philadelphia Enquirer editorial today, there was an article about nuclear energy, talking about that the NRC believes that it is the most regulated industry, and the most regulated government agency. And it should be.

And we hope that those regulations are there to protect the natural resources of the river and that we, again, hold PSE&G as they go through this process, to the highest standards possible. Thank you very much.

DELAWARE RIVERKEEPER®

Testimony
Fred Stine, Citizen Action Coordinator for the
Delaware Riverkeeper Network
11/5/2009

I would like to thank the NRC for this opportunity to speak to the license renewal application submitted by PSE&G and Excelon. We understand the purpose of today's duel public meetings is to discuss the processes around the license renewal and requisite EIS scoping and I will speak directly to that.

But first, the Delaware Riverkeeper Network wants to reaffirm our long-standing position and call to convert the Salem Generating Station to closed cycle cooling as mandated by Section 316(b) of the Clean Water Act. The Act states that generating plants such as Salem "shall be required that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." The application before the NRC does not call for the compliance of the Clean Water Act as it relates to best technology available.

According to a study conducted by a NJDEP hired expert in 1989 as well as experiences at other facilities, installation of closed cycle cooling towers at Salem would reduce their fish kills by 95%. And dry cooling at Salem could reduce their fish kills by 99%. SHC-4-3

Speaking now directly to the environmental impact study, the Delaware Riverkeeper Network calls on the NRC and other reviewing agencies to hold the applicant to the highest scientific and regulatory standards as they prepare the EIS. Previous permits issued to PSE&G were based on data which were found to be faulty, misleading, biased and incomplete. In 1999 for instance, when PSE&G's permit came up for renewal, the company submitted over 150 volumes of information, data and arguments to support its case that it should be allowed to continue to kill Delaware River fish unimpeded.

Every year the Salem Nuclear Generating Station kills over 3 billion Delaware River fish including:

Over 59 million Blueback Herring
Over 77 million Weakfish
Over 134 million Atlantic Croaker
Over 412 million White Perch SHC-4-4

Delaware Riverkeeper Network
300 Pond Street, Second Floor
Bristol, PA 19007
tel: (215) 369-1188
fax: (215) 369-1181
drkn@delawareriverkeeper.org
www.delawareriverkeeper.org

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Over 448 million Striped Bass
Over 2 billion Bay Anchovy

Even NJDEP's own expert agrees that PSE&G's assertions were not credible and were not backed by the data and studies PSE&G had presented. In fact, according to ESSA consultants, hired by NJDEP, PSE&G had greatly underestimated its impacts on Delaware River fish. According to ESSA, PSE&G "underestimated biomass lost from the ecosystem by perhaps greater than 2-fold." (ESSA report p. xi) And "... the actual total biomass of fish lost to the ecosystem ... is at least 2.2 times greater than that listed" by PSE&G. (ESSA Report p. 75)

ESSA Technologies' 154 page review of PSE&G's permit application documented ongoing problems with PSE&G's assertions and findings including bias, misleading conclusions, data gaps, inaccuracies, and misrepresentations of their findings and damage. Some examples of ESSA's findings:

- With regards to fisheries data and population trends, ESSA said "The conclusions of the analyses generally overextend the data or results." (p. ix)

- PSE&G "underestimates biomass lost from the ecosystem by perhaps greater than 2-fold." (p. xi) "... the actual total biomass of fish lost to the ecosystem ... is at least 2.2 times greater than that listed in the Application." (p. 75)

- "Inconsistency in the use of terminology, poorly defined terms, and a tendency to draw conclusions that are not supported by the information presented detract from the rigor of this section and raises skepticism about the results. In particular, there is a tendency to draw subjective and unsupported conclusions about the importance of Salem's impact on RIS finfish species." (p. 77)

- Referring to PSE&G's discussion and presentation of entrainment mortality rates ESSA found PSE&G's "discussion in this section of the Application to be misleading." (p. 13)

The ESSA report contained no less than 51 recommendations for actions which PSE&G needed to take on its 2001 permit application before DEP made its decision, but that did not happen. It is our understanding that while NJDEP pursued some of these (which ones we do not know because it was not referenced in the draft permit documents) many of them were never addressed, and still others were turned into permit requirements to be dealt with over the next 5 years.

In addition to ESSA recommendations, NJDEP received comment from the State of Delaware and USF&W, both of whom conducted independent expert review of the permit application materials and found important problems with sampling, data, analyses and conclusions.

While we are urging you today to hold the applicant to high standards, I conclude be re-stating the fact that because Salem is clearly having an adverse environmental impact on the living resources of the Delaware Estuary and River, regardless of PSE&G's self-serving claims based on faulty scientific studies, the Clean Water Act requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact."

SHC-4-4

END

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Fact Sheet

Largest Predator in the Delaware Estuary

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Salem kills over 3 billion RIS fish a year.

Every year the Salem Nuclear Generating Station kills over 3 billion Delaware River fish including:

- Over 59 million Blueback Herring
- Over 77 million Weakfish
- Over 134 million Atlantic Croaker
- Over 412 million White Perch
- Over 448 million Striped Bass
- Over 2 billion Bay Anchovy

(Figures provided are numbers of fish killed. Source: correspondence from US Fish & Wildlife Service to NJDEP, June 30, 2000 relying on PSE&G permit application data)

The permit issued was based on data which is faulty, misleading, biased and missing information and data provided by PSE&G.

In 1999, when PSE&G's permit came up for renewal, the company submitted over 150 volumes of information, data and arguments to support its case that it should be allowed to continue to kill Delaware River fish unimpeded. To its credit, NJDEP took the advice of environmental groups including Delaware Riverkeeper Network, ALS, NJEF, EAGLE, COA and the Coalition for Peace and Justice, and hired an independent expert to help them review PSE&G's materials. But, to its discredit, NJDEP did not require PSE&G to address the many shortcomings and DEP apparently ignored their expert's findings, just as they did with Versar in 1994.

ESSA Technologies' 154 page review of PSE&G's permit application documented ongoing problems with PSE&G's assertions and findings including bias, misleading conclusions, data gaps, inaccuracies, and misrepresentations of their findings and damage. Some examples of ESSA's findings:

- With regards to fisheries data and population trends, ESSA said "The conclusions of the analyses generally overextend the data or results." (p. ix)
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In addition, NJDEP received comment from the State of Delaware and USF&W, both of whom conducted independent expert review of the permit application materials and found important problems with sampling, data, analyses and conclusions.

PSE&G Continues to Poison Sensitive Marshlands Annually and Does Not Mitigation Salem's Fish Kills

To date, PSE&G has applied over 22,000 pounds of herbicides, aerially and by hand, to 2,500 acres of sensitive marsh land. *(Source: NJEF 2003 glyphosate analysis)* The loss of food, shelter and habitat are unacceptable.

http://www.delawareriverkeeper.org/newsresources/factsheet.asp?ID=11 11/5/2009

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The wetlands experiment fails to reduce the impingement and/or entrainment impacts of Salem and therefore does not fulfill the requirements of 316(b), PSE&G is unable to demonstrate that their wetlands experiment, even if successful (which is doubtful at best), actually provides benefits to the estuary ecosystem.

- PSE&G failed to conduct any baseline data that would demonstrate whether or not food and habitat were limiting factors for the aquatic communities of the Delaware River system and therefore whether or not wetlands restoration could have contributed positively to their numbers.
- PSE&G is unable to demonstrate that the wetlands it is seeking to restore are superior, in terms of food and habitat for fish and other aquatic populations, than *phragmites*. Scientific studies are documenting that *phragmites* in fact is not of inferior value to *spartina*, that it does provide usable and used food, shelter and cover to both aquatic and terrestrial species. Therefore, PSE&G's entire wetlands experiment is based on a false premise.
- The sustainability of the wetlands *phragmites* reduction is dependent on annual herbicide treatment.
- PSE&G has failed to demonstrate that even if it is successful at replacing the existing *phragmites* in the Cohansey and Alloway sites with other species of plants, that this change in vegetation is sustainable and will not be overrun by neighboring stands of *phragmites* within a matter of years.
- At the Alloways site the interim goal was met through the removal of approximately 1,000 acres of *Phragmites* dominated wetlands from the restoration program—an action which then skewed the perceived results by removing from the program a problematic site
- Actions by PSE&G in the *phragmites* dominated sites is not increasing fish utilization of those areas. PSE&G monitoring at Alloway Creek includes sites (a) dominated by *Phragmites*, (b) dominated by *Spartina* or (c) under treatment for *phragmites* removal ("*Treated*" sites). PSE&G 2000 monitoring showed that within the Alloway Creek study area, fish abundance was similar at all three types of sites. In 2002, fish abundance at the *phragmites* dominated site at Alloway Creek was approximately twice as great as that seen at *Spartina* dominated site and the treated site at Alloway Creek. Reproduction of mummichog and Atlantic silverside was seen in the *phragmites* dominated sites both prior to and following the treatment of *phragmites* andgrowth patterns were seen to be similar for mummichog and Atlantic silverside both pre and post treatment as well. Studies also indicate that mummichog use *phragmites* as a food source in *phragmites* dominated sites. These results indicate that *Phragmites* eradication has not demonstrated an increased utilization of the site by fish and/or increased fish production.
- Tidal flow has successfully returned to the New Jersey salt hay farms. Not all sites have attained percent coverage goals for *spartina* coverage but *spartina* and other target species do dominate the three sites. The restored salt hay farms that were originally dominated by *Spartina* have reached the set goal of marsh coverage after repeated herbicide applications (Dennis Township and Maurice River) but the one farm that was dominated by *phragmites* (Commercial Township) has not yet reached the interim goal of 45% *spartina* coverage and doesn't come close to the vegetative coverage of the reference marsh at Moores Beach.
- Young of the year fish assemblages in the salt hay farms were similar between the restored salt marshes and the reference marshes including size composition, seasonal patterns of occurrence and species composition. While predator species such as striped bass and white fish were found to be utilizing the restored salt hay farm marshes with a higher diversity of species and a higher density of predator fish as compared to the reference marshes, forage studies indicated that food habits of the fish were similar between the restored salt marshes and the reference marshes.
- According to PSE&G data 2000-2002 there has been little to no usage of fish ladders installed at Garrison Lake or Coopers Lake. While evidence of spawning was seen in all sites except Garrison Lake, it does not appear that the stocking efforts have been successful in establishing the return of offspring to the fish ladder sites. Three of the four sites with large numbers of fish utilizing the ladders received limited stocking, indicating that the fish utilizing the fish ladders are most likely pioneers, rather than either returning stocked fish or offspring of stocked fish. The sites that have received the largest numbers of stocked fish continue to show limited use of the fish ladders by adults.

PSE&G's mitigation/restoration efforts are not mitigating the impingement and entrainment impacts of the Salem facility.

PSE&G data and analysis on the record as of 2003 does not demonstrate an increase in baywide abundance values of the representative important species or Atlantic silverside since PSEG completed the marsh restoration and fish ladder installations. Striped bass data is difficult to interpret as the abundance numbers in the Delaware are apparently linked to abundance in Chesapeake Bay. Overall, it appears that striped bass have increased, although this increase is not statistically significant. Weakfish and white perch declined in numbers after 1997, although the decline was not statistically significant. A decline was also seen for spot, bay anchovy, Atlantic silverside (1994-2001), and American shad, with the decline being statistically significant for American shad when comparing 1991-1994 data to 1997-2001 data. Increases have been seen in blueback herring, although these increases are not statistically significant. PSE&G's mitigation/restoration efforts are not mitigating the impingement and entrainment impacts of the Salem facility.

The costs of closed cycle cooling at Salem has not been demonstrated to outweigh its benefits.
It would cost only about $13 a year per rate-payer (assuming an average electric bill of $100 a month) to install closed cycle cooling at Salem. This $13 would benefit the health of our fisheries as well as commercial and recreational fishing organizations and businesses.

PSE&G has been given over a decade to carry out its alternative strategy for "mitigating" the impacts of Salem. It has been unable to demonstrate this program is beneficial to the environment and residents of New Jersey. It is time to hold PSE&G accountable and to require implementation of closed cycle cooling at Salem

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MR. HASSLER (AFTERNOON): Good afternoon. My name is Charlie Hassler, and I came here to speak in support of the PSE&G licensing for the Salem and Hope Creek units.

I'm a lifelong-resident of Salem City, and I work down at the Salem Hope Creek nuclear facility for the past approximately 34 years. I'm currently a business agent for the International Brotherhood of Electrical Workers, Local Union 94, which represents the organized labor who are employed permanently at the facility.

Additionally I'm a member of the New Jersey IBEW, the umbrella organization, with about 35,000 members. New Jersey IBEW is also on record as supporting the relicensing efforts of the Salem and Hope Creek stations. SHC-5-1

Our support is based upon understanding of how the NRC proceeds with the relicensing effort. It is an informed rational support, and comes only with our belief that the safety of our members, and the public at large, will be assured by the continued operation of these plants.

The three units have been operating at capacity of about 90 to 95 percent in the past several years. Prior to the outages now in progress at Salem unit 2, that unit ran for 515 consecutive days at a capacity factor of one hundred percent.

This type of performance can only be achieved through diligent processes, procedural adherence, while maintaining and operating the plants. The personal standards of all workers are very high. What other industry has improved the standards and operating capacities the way it has been done in nuclear? This is truly the most watched, from the outside, and scrutinized from within.

The Institute of Nuclear Power Operators, The Nuclear Management and Resource Council, and the NRC itself, does more internal evaluations than to groups in any other industry.

This is an industry that if you are not bumping the top quartile in performance, you had better have a better plan, or you are in trouble. The output of the three stations supplies New Jersey with about 52 percent of its electric needs. SHC-5-1

Producing this electricity is done without creating green house gases, which is an important and critical component to this discussion, given the global warming situation.

Without these plants, the reliability of the electric delivery to meet demand would be put at risk. Next, American's reliance on foreign energy imports continues to stress our economy, costing Americans jobs, and putting the middle class, itself, at risk.

A sound energy policy is our nation's best interest, and nuclear energy must play an important role in that policy. Finally, we must all recognize, that license renewal does not come open-ended, without ongoing monitoring.

Safety and performance standards, just as they are today, will continue for the entirety of the time the plant operates. If the plant falls below the acceptable standards, myself and the members of my union, will be the first to speak out.

If a major issue, safety-wise arises in the future, you can all rest assured that the NRC has the ultimate power to come in, take away the keys, shut the doors, and close the plant down.

Thank you for the opportunity to speak.

SHC-5-1

MR. HASSLER (EVENING): Good evening. My name is Charles Hassler, and I'm here tonight to speak in support of the PSEG's relicensing of the Salem and Hope Creek nuclear facility.

I have been on the facility, as a worker, for 34 years. Right now I'm currently a business agent for the International Brotherhood of Electrical Workers, Local Union 94.

Additionally I'm a member of the New Jersey IBEW, which is the umbrella group in New Jersey that has an organization of about 35,000 members. New Jersey IBEW also is on record as supporting the relicensing of the Salem and Hope Creek stations.

As I said, we represent the organized labor who are permanently employed on the island, at the facility. Our support is based on our understanding of how the NRC proceeds with this relicensing effort.

It is an informed, rational, support. And it comes only with our belief that the safety of our members, and the public at large, will be assured by the continued operation of the plants.

The three units have been operating at a capacity factor of about 90 to 95 percent for the past several years. Prior to the outage that is going on right now at Salem unit 2,

SHC-5-2

that unit ran for 515 consecutive days at a capacity of over 100 percent.

This type of performance can only be achieved through diligent processes, and procedure adherence, while maintaining and operating the plant.

The personnel standards are high for all workers.

What other industry has improved the standards and operating capacity the way that it has been done in nuclear? This is truly the most watched, from the outside, and scrutinized from within.

The Institute of Nuclear Power Operators, the Nuclear Management and Resource Council, and the NRC itself do more internal evaluations than groups in any other industry.

This is an industry that if you are not bumping at the top quartile, you had better have a plan ready and in place or you will be in trouble. The output of the three stations supply New Jersey with about 52 percent of its electric needs.

Producing this electricity is done without creating greenhouse gases, which is an important and critical component to this discussion, given the global warming situation.

Without these plants the reliability of electric delivery, to meet demand, would also be at risk. Next, Americans

SHC-5-2

reliance on foreign energy imports continues to stress our economy, costing Americans jobs, and putting the middle class, itself, at risk.

A sound energy policy is in our nation's best interest, and nuclear energy must plan an important role in that policy. Finally, we must all recognize that license renewal does not come open-ended, and without ongoing monitoring.

Safety and performance standards, just as they are today, will continue for the entirety of the time the plant operates. If the plant falls below acceptable standards, myself and the members of this union, will be the first to speak out.

If a major safety issue arises in the future, we can all be assured that the NRC has the ultimate power to come in, take the keys, shut the doors, and close the plants down.

Thank you for your time.

SHC-5-2

MR. FRICKER (AFTERNOON): Good afternoon, and thank you for giving me the opportunity to make a comment regarding the license renewal application of Salem and Hope Creek.

My name is Carl Fricker, and I'm the vice president of operations and support for PSE&G Nuclear, and I am part of the leadership team that is responsible for the safe and reliable operation of our plants.

I have over 25 years of both military and commercial nuclear power plant experience. And I have worked at PSE&G Nuclear for the past 14 years. I have had positions in operations, maintenance, quality assessment, and for the last four years, prior to my current job, I was the plant manager at Salem.

SHC-6-1

At PSE&G we understand our obligation to the local community, to the environment, to our friends, families, and coworkers, to provide safe, reliable, economic, and green energy.

In New Jersey over 50 percent of the state's electricity comes from nuclear power. In fact PSE&G Salem and Hope Creek Nuclear Plants, is the second largest nuclear facility in the country.

Each day those plants generate enough electricity to supply three million homes. In addition we are able to meet the region's energy needs without emitting any green house gases.

Today nuclear power produces over 70 percent of our nation's carbon-free electricity. We take great pride in that and recognize our important role in fighting climate change now and in the future.

As you hear earlier, our current operating licenses expire in 2016 for Salem unit 1, 2020 for Salem unit 2, and 2026 for Hope Creek. In 2006 we made the decision to pursue license renewal.

We formed a dedicated team that worked for over two and a half years, or about 122,000 person hours, to prepare our application. That was about 4,000 pages of application.

SHC-6-1

This review involved a review of thousands of documents, a detailed review of our equipment, and component performance, and a rigorous review of the existing maintenance and engineering programs, to ensure that Salem and Hope Creek will safely operate for an additional 20 years.

Over the past 10 years we have invested over 1.2 billion dollars in our plants, including last year's steam generator replacements at Salem unit 2, and the various upgrades that supported Hope Creek's extended power uprate.

As part of license renewal we also reviewed any environmental impacts that, by continuing to operate, the Salem and Hope Creek nuclear plants for 20 years, would cause.

We consider ourselves environmental stewards, and since this is an environmental scoping meeting, I want to touch on this subject.

In addition to producing no green house gases, PSE&G has no adverse radiological impacts on our environment. The NRC requires PSE&G Nuclear, and all U.S. nuclear plants, to maintain an environmental monitoring program, to monitor local radiation levels. Annually we perform over 1,200 analysis on over 850 environmental samples, including air, water, soil, and food products like milk, and farm crops. All analyses samples are cross-checked with other laboratories to ensure precision and accuracy.

We are also closely monitored by the New Jersey Department of Environmental Protection's Bureau of Nuclear Engineering. The Bureau of Nuclear Engineering independently monitors the local environmental around PSE&G Nuclear, through a remote monitoring system that provides real time readings.

The sampling and monitoring has shown that there is no adverse impact to the environment. We are also proud stewards of

SHC-6-1

the Delaware river and estuary, through our estuary enhancement program.

This program involves ongoing restoration, enhancement, and preservation of more than 20,000 acres of degraded salt marsh, and adjacent uplands within the estuary.

The estuary enhancement program is the largest privately funded wetlands restoration project in the country. More importantly, it was created with extensive public participation, and open communication with regulatory agencies and the public.

As a result all the estuary enhancement program sites are open to the public, and offer boardwalks, nature trails, outdoor education, and classroom facilities. SHC-6-2

Studies show that the overall health of the estuary continues to improve. In addition, analysis of long-term fish populations in the estuary show that, in most cases, the populations are stable or increasing.

And that fish population trends are similar through the other areas along the coast. We also recognize our important role and impact to the local community.

PSE&G Nuclear is Salem County's largest employer with over 1,500 employees. Some members of our workforce, as with all companies, are preparing to retire in the next few years.

As such we have looked to partner with local communities, with our local community, to meet our needs to providing good paying local jobs. We have launched innovative partnerships with the Salem County Community College, and the Salem County Vocational Technical schools, to develop specialized training programs.

Both have been overwhelmingly successful, and will lead to a skilled workforce that will only strengthen the local economy. In Salem County we provide more than 1.4 million dollars, each year, to the local economy through local property taxes.

This funding is vital to supporting local schools and projects. From an economic development point of view, we have also helped to drive the local economic development through projects like revitalization of downtown Salem, and the construction of the Gateway Business Park in Oldmans Township.

We are also active partners in the Salem Main Street Program, and the Salem County Chamber of Commerce. Our support also goes well beyond dollars.

SHC-6-3

Many of our employees are active participants and supporters within the local community. SHC-6-3

In addition to being a good neighbor, being transparent is an important aspect of building trust. We are fortunate to have an excellent relationship with our local stakeholders, and that is not something we take for granted.

With them there is no surprises. We are proactive and engage them when challenges arise, so that they have an understanding of the challenges and have their questions answered.

This year we have provided more than 30 site tours for key stakeholder groups, close to 500 elected officials, educators, students, community and trade groups, have been given an inside look at PSE&G Nuclear. SHC-6-4

What better way to answer their questions than to let people see, first-hand, the important role of nuclear power. By the end of this year we will also open the doors to our new energy and environmental resource center, that is housed at our old training center, on Chestnut Street in Salem.

This new information center will be used as an interactive display to educate the public about climate change, and the various ways we can all have a positive impact on our environment.

The center will be open to groups for tours, and provide meeting spaces for local organizations. In closing, PSE&G Nuclear looks forward to working with the NRC, and the public, as you review our license renewal application.

We have worked hard to provide safe, reliable, economic, and green energy for the past 30 years, and look forward to the opportunity to build on this success in the future. Thank you. SHC-6-4

MR. FRICKER (EVENING): Good evening. Thank you for the opportunity to make a comment regarding the Salem and Hope Creek Nuclear license renewals.

My name is Carl Fricker, and I'm the vice president of operation support for PSEG Nuclear. I'm part of the leadership team that is responsible for the safe and reliable operations of the plants.

I have 25 years of experience, both in commercial and Navy nuclear power programs. And I have worked at PSEG for 14 years. I have had positions in operations, maintenance, quality assessment, and my last job for the last four years, prior to my current job, was the Salem plant manager.

At PSEG we understand our obligation to the local community, to the environment, our friends, families, co-workers, to provide safe, reliable, economic and green energy.

SHC-6-5

In New Jersey, as was mentioned, over 50 percent of the state's electric generation comes from nuclear power. In fact, PSEG Nuclear at Salem and Hope Creek is the second largest nuclear facility in the country.

Each day they generate enough electricity to supply three million homes. In addition, we are able to meet the region's energy needs without generating any greenhouse gases.

Today nuclear power produces over 70 percent of our nation's carbon-free electricity. We take great pride in this, and recognize our importance and our ongoing role in fighting global climate change now and in the future.

As was mentioned, our current operating licenses expire for Salem unit 1 in 2016, Salem unit 2 in 2020, and Hope Creek in 2026. In 2006 we decided to pursue license renewal.

We established a dedicated team that worked for two and a half years, or 122,000 person hours, to prepare the station's application that is approximately 4,000 pages.

This involved the review of thousands of documents, a detailed review of equipment, components, and a rigorous review of existing maintenance and engineering programs to ensure that Salem and Hope Creek will safely operate for an additional 20 years.

SHC-6-5

Over the past ten years we have invested more than 1.2 billion dollars in equipment upgrades, which included, last year, a steam generator replacement at Salem unit 2, and various upgrades that supported Hope Creek's power uprate.

As part of license renewal we also reviewed any environmental impacts that would occur having the plants operate for another 20 years. We consider ourselves environmental stewards.

And since this is an environmental scoping meeting, I want to touch on the subject. In addition to producing no greenhouse gases, PSEG has no adverse radiological impacts on the environment.

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All analyzed samples are cross checked with other laboratories to ensure precision and accuracy. We are also closely monitored by the New Jersey Department of Environmental Protections, Bureau of Nuclear Engineering.

The Bureau of Nuclear Engineering independently monitors the local environment around PSEG Nuclear through remote monitoring systems, that provide real time readings.

This sampling and monitoring has shown that there is no adverse impact to the environment. We are also proud stewards of the Delaware Estuary, through our estuary enhancement program.

SHC-6-5

This program includes ongoing restoration, enhancement, and preservation of more than 20,000 acres of degraded salt marsh and adjacent uplands in the estuary.

SHC-6-6

The estuary enhancement program is the largest privately-funded wetlands restoration project in the country. More importantly it was created with extensive public participation, and open communications with regulatory agencies and the public.

As a result all estuary enhancement program sites are open to the public, and offer boardwalks, nature trails, outdoor education, and classroom facilities.

Studies have shown that the overall health of the estuary continues to improve. In addition, analysis of long-term fish populations in the estuary show that most cases populations are stable or increasing, and that the fish population in this area trends are similar to other areas along the coast.

SHC-6-6

We also recognize our impact to the local community. It was mentioned earlier that PSEG Nuclear is Salem County's largest employer. We have over 1,500 employees. As many companies are experiencing, some members of our work force are preparing to retire in the next few years.

As such, we have looked to partner with the local community to meet our needs and provide good paying local jobs. We have launched an innovative partnership with the Salem County

SHC-6-7

Community College, and the Salem County Vocational Technical Schools, to develop specialized training programs.

Both have been overwhelmingly successful, and will lead to a skilled work force that will only strengthen our local economy. In Salem County we provide more than 1.4 million dollars, each year, to the local economy through property taxes.

This funding is vital to the supporting of local schools and projects. From an economic development point of view, we have also helped drive the local economic development projects, like the revitalization of Salem, and the construction of the Gateway Business Park, in Oldmans Township.

We are active participants and partners in the Salem Main Street Program, and the Salem County Chamber of Commerce. Our support goes well beyond dollars. Many of our employees are active participants and supporters within the local community.

SHC-6-7

In addition to being a good neighbor, transparency is an important aspect of building trust. We are fortunate that we have an excellent relationship with our stakeholders, and it is not something that we take for granted.

With them we make sure that there are no surprises. We are proactive, and engage them when a challenge arises, so they

SHC-6-8

understand the challenge, and have the opportunity to ask their questions, and have answers.

This year we provided more than 30 site tours for key stakeholder groups. Close to 500 elected officials, educators, students, community and trade groups have been on-site to get an inside look at PSEG Nuclear.

What better way to answer questions than to let people see, first-hand, the important role of nuclear power? By the end of this year we will also open our new energy resource and environmental center, housed at our old training center, which is on Chestnut Street in Salem.

This new information center will use interactive displays to educate the public about climate change, and the various ways we can all have a positive impact on our environment.

The center will be open to groups for tours, and provide meeting spaces for local organizations.

In closing, PSEG Nuclear looks forward to working with the NRC, and the public, as you review our license renewal application. We have worked hard to provide safe, reliable, economic and green energy, for more than 30 years, and look forward to the opportunity to build on this success in the future. Thank you.

SHC-6-8

DR. CONTINI: Good afternoon, thank you. I am Dr. Peter Contini, president of Salem Community College, a position that I have held for the past 12 years.

And in that capacity I'm here to acknowledge the support of the college for the license renewal of PSE&G for Salem 1 and 2, as well as Hope Creek.

We base that on our knowledge and experience. And you have already heard that PSE&G Nuclear is certainly well regarded as a corporate leader in our county.

Certainly through their community leadership, both participating on groups, and supporting groups, they have directly affected the quality of life in our county.

Additionally we have seen, first-hand, the highly professional organization that they are, focused on safety, and security. And, certainly, generating a most valuable renewable energy source, one that we think directly addresses New Jersey's energy plan 2020, as well as the potential growth in this county, and throughout the state. SHC-7-1

We view them as, certainly, an economic development and workforce driver. And we know, first-hand, how that happens. You just heard Carl speak about a wonderful opportunity that came about as a result of that level of partnership.

We received, this past February, a 1.7 million dollar three year grant from the U.S. Department of Labor, Community Based Job Training. It has two focuses. One, nuclear energy and, two, sustainable energy.

SHC-7-1

And the partners in that grant are PSE&G Nuclear as well as Energy Freedom Pioneers, working very collaboratively with our vocational school, Ranch Hope, Calgary Redevelopment, the New Jersey Department of Labor as well as Workforce development and, certainly, our one stop center.

Their support is not just verbal. Their support is certainly implementing. And as you know, and you heard Carl say, there is going to be a growing need for employees, as certainly portions of the workforce ages out, and we hope, also, the expansion of opportunity in the future.

SHC-7-2

As a result we work collaboratively with PSE&G Nuclear, in focusing on a particular area that we think is of great need, an energy, nuclear energy technician position.

We were able to couple with them, and partner at the national level with the Nuclear Energy Institute. And we were selected as one of six community colleges, across the country, that are working on standardizing the curriculum to ensure that educational experience that our students have, will not only prepare them, but certainly ensure safety and security in the future in this field.

And you also heard about the center that has been revitalized in Salem City. Well, I'm proud to tell you that a portion of that center will be hosting a portion of our program.

And through a high tech classroom, as well as laboratory facilities, our students will be working with state of the art equipment. And, most importantly, be supportive both in scholarships, as well as internships.

So we see this as a real win-win. Thinking about this, that we have only, in less than one year, been able to implement this program, we now have a fully accredited nuclear energy technician program, technology program, what we refer to as NET, we now have over 50 students in that program.

The corresponding program, Sustainable Energy, is also working at about 20 students. We see that balance, and PSE&G Nuclear sees that balance, also. And they have been very collaborative in working with Energy Freedom Pioneers, as we look for other alternatives to energy in addition to nuclear.

These are important things, they are important things for our community and, certainly, for our students. But they also go beyond. Two years ago we had an emergency in our Salem center,

SHC-7-2

hosting our one-stop career center. A fire, a fire that immediately caused the dislocation of over 30 workers, and 200 clients a day.

Within two hours we had a commitment from PSE&G Nuclear to relocate that entire program to the former training center. And within two days we were fully operational for the next four months.

SHC-7-2

It is an organization that understands their role in the community, certainly puts safety and security as a top priority. But, more importantly, understand the value to our community.

And, for that reason, we fully support their relicensing. Thank you.

SHC-7-3

MR. BAILEY: Good afternoon, my name is David L. Bailey, Jr. I am the chief executive officer of Ranch Hope, Incorporated. And, personally, I'm a lifelong resident, growing up within minutes of the Salem and Hope Creek in Alloway township, and now raising my family here, as well.

Ranch Hope, Inc., is a 501C(3) non-profit organization, founded in 1964. Again, our Alloway headquarters are within minutes of the Salem and Hope Creek facilities. Our mission is to provide behavioral health care, educational, and adventure-based environments for children and families from throughout the state of New Jersey, and within the Delaware Valley.

Through its generosity and support of local organizations, such as Ranch Hope, PSE&G Nuclear has touched the lives of thousands of residents, making our community a better place to live.

At Ranch Hope's Alloway campus PSE&G Nuclear supports our efforts to create a green community for children with treatment and educational facilities, not only environmental responsible, but energy efficient, and healthy for children and staff to live and work.

SHC-8-1

This unique collaboration with PSEG Nuclear not only focuses on changing the lives of children and families, but also energy efficiency, two topics you don't normally see together. SHC-8-1

Just as importantly, PSEG Nuclear demonstrates a level of transparency within our community here in Salem County. Nuclear power represents a mystique that many of us will never fully understand.

However, PSEG Nuclear has taken the time to keep the local community informed. Groups of key stakeholders, which I was humbled to be one myself, including elected officials, educators, business and community leaders, recently toured the Salem and Hope Creek facilities, and we learned, first-hand, the importance of nuclear power. SHC-8-2

As someone who was fortunate enough to visit these two generating stations, I feel even more comfortable, having seen the safety and security measures they take to provide us with clean, reliable energy, on an every day basis.

This being the case, Ranch Hope, and the families and the communities that we support, fully support the license renewal applications for PSEG Salem and Hope Creek nuclear facilities. Thank you.

MS. WICHMAN: Hi, my name is Kelly Wichman, and I'm an employee of PSEG Nuclear in the nuclear fuels department. I'm a safety analysis engineer, and this is my first full-time job.

Both my husband and I moved to Woodstown, New Jersey, just down the road, from the midwest a year and a half ago, to take positions at the Salem and Hope Creek site, and we bought a house here, with the intentions of staying for some time.

I came here today because I believe that Salem and Hope Creek should be granted operating license extensions. I chose a position in the nuclear industry because I think it has staying power.

I majored in engineering in college, with the intention of coming into this industry. And, as I progressed in my education, I found more and more reasons why nuclear power is really a great option for electricity production. SHC-9-1

From an engineer's standpoint, nuclear fuel is one of the most efficient fuels producing thousands of times more energy than a chemical reaction with the same amount of material. Say, for example, coal, oil or gas.

In addition, the land footprint is small, compared to other generating options which, to me, makes nuclear power an obvious choice in a world where finite resources are available.

My position at PSEG Nuclear has provided me an opportunity to explore new parts of the country, and I have taken advantage of living within a few hours of so many cities.

I have also taken advantage of all the career-related opportunities offered by my job. I have joined two professional organizations, the North American Young Generation in Nuclear, and the American Nuclear Society.

With Young Generation in Nuclear, I formed relationships with more of my coworkers, attended professional development conferences, participated in charity drives, and taught kids in the area about power generation at the Salem Votech.

With those organizations I have seen the positive influence that the plants have on the area, and on the people. I work there because I feel that the opportunities are great, and I feel that I'm doing something meaningful, by helping produce electricity that everyone uses.

I believe the plant's continued operating presence in the area will only be of benefit to the community. Thanks.

SHC-9-1

MS. NAGAKI: So my name is Jane Nagaki, and I'm vice-chair of the New Jersey Environmental Federation, which is the state's largest non-profit environmental organization.

And we raise several environmental issues regarding the relicensing. First I would like to support the comments of Fred Stein, from the Riverkeeper.

And I won't repeat everything that he said, but the Environmental Federation is, also, very firmly committed to the idea that if the relicensing goes forward, on Salem 1 and 2, that best available technology should be applied at those plants, which would be cooling towers to offset the millions of gallons of water that cycle through that plant every day.

There has been a lot of talk, today, about how nuclear energy produces no air emissions. And, generally, when we think about environmental impacts we are thinking air, releases to the air, releases to the water, releases to the land. SHC-10-1

And while it is true that there may be no air emissions, from the plant, there certainly is a consumptive use of millions of gallons of water a day, run through the cooling cycle, and then discharged back into the Delaware Bay, with a concurrent loss, as Fred mentioned of billions of fish per year, in all stages of life, from larval stage, to small stage, to large scale fish that are impinged on the once-through cooling system.

Which I have toured, by the way, and witnessed the huge structure that takes through millions of gallons of water a day.

So if there is one environmental issue that I would like to highlight today, is the impact of the Salem Nuclear Plant on water in the Delaware Bay, and the concurrent fish and wildlife that that water, the Delaware Bay supports.

We talked about nuclear energy as being a major employer in this area, and I'm certainly respectful of the workers that work there, that keep the plant safe every day, and the niche in the economy that it provides. SHC-10-1

But there is, also, a huge other economy in the Delaware Bay that is the fishing industry, that is severely affected by the operation of this plant.

And so if I were to say the huge, the most huge environmental impact of this plant, is the impact of water, in that once through cooling system. That needs to be addressed in the Environmental Impact Statement.

As far as, you know, there is no radiation produced at this plant, there is some radiation produced at this plant. It meets limits, so called acceptable limits.

There is waste that is stored on-site. And so another environmental issue, that the Environmental Impact Statement should address, is how much more waste is going to be generated and stored at the plant, at those enclosures that currently keep all the waste, ever produced at that plant, on the site forever.

So waste production concurrent with the relicensing is another very major environmental issue.

SHC-10-2

What is unique about our community? What is unique about artificial island, is that it is an island that was constructed of dredge spoil material.

It is not an island that existed before the geology of the time. So one of the concerns, environmental concerns would be how stable is the structure of the island to support this plant for another 20 years. Or three plants, actually.

I think that issue will be addressed, more specifically, tonight by another environmental group. What is the effect of sea level rise? We talked about global warming and how nuclear power doesn't produce the kinds of emissions that contribute to global warming.

SHC-10-3

But there is global warming going on, and there is sea level rise. What is the effect of sea level rise on the plant's artificial island? You know, is the island going to be inundated with water, how much over the next few years?

Does more infrastructure need to be built there to support the plant? We know that salt water, and the effects of the salinity of the bay have contributed to the rusting out of parts of the plant. We know that there has been extensive replacement of structures, and underground piping at the plant. And that is both, you know, that is an environmental impact, the salinity of the area, on the integrity of the structure of the plant.

And that is an environmental issue that needs to be integrated into the safety and the aging issues of the plant.

SHC-10-3

Let's see. So going back to another impact, and the result of the Salem 1 and 2 plants, not having cooling towers is that PSEG Nuclear entered into a very large estuary enhancement program, which was referred to earlier, preserving 20,000 acres of wetlands.

And I would be remiss if I didn't mention a concern that environmental groups raised at the beginning of the restoration project, because many of the acres of wetlands were

SHC-10-4

restored simply by breaching dikes of old salt hay farms, and allowing inundation of phragmites by salt water.

And thus controlling the phragmites, and growing a more beneficial kind of vegetation, called Spartana. But there are acres and acres of phragmites, you know what they are, the tall waiving foxtails, as they are often called, which were considered nuisance vegetation, or not favorable vegetation in the wetland restoration.

And so in order to control that phragmites, massive aerial herbicide event took place starting in 1995 and '96, over 2000 acres were really sprayed with a pesticide called Glyphesate. And it was thought that one, maybe two applications of that herbicide would take care of the problem.

SHC-10-4

But, to this day, in the year 2009, and continuing on until at least 2013, annual applications by herbicide by aircraft are made to wetlands, as part of this project.

The acreage is down now, to around 120 acre realm. But it has been as high as thousands of pounds of a year. And so one of the environmental issue raised by this is, is there going to be continued applications of an herbicide, in wetland areas, as part of this restoration project, which was meant to offset the impacts caused by the lack of cooling towers.

The reason we are concerned about this application of herbicides is that it actually triggered an increase in the use of this herbicide, state-wide.

PSEG kind of became the model for how to restore wetlands. And so many other wetland restoration projects began utilizing this methodology. And the result has been a nine-fold increase in the use of Glyphesate in the state of New Jersey.

And so while the use at this particular Alloways creek area is decreasing, not over yet, but still decreasing, the increase in the use, state-wide, is of concern because as you know pesticides generally have a habit of infiltrating our groundwater and surface water. SHC-10-4

They become part of our drinking water, part of our surface water. And the effects of this herbicide has been linked to cancer effects, birth defect effects, effects on fish, insect populations, and so forth.

So we certainly raise this as an issue that needs to be addressed, because nobody has really looked at the cumulative impact of this year, after year application of herbicide to control a nuisance plant, all in the name of restoring wetlands.

So I think that is the extent of the issues I wanted to raise today. But I do want to say that some of the safety SHC-10-5 concerns, and environmental concerns, are related mainly to this issue of the aging of the plant, the salinity, the lack of a firm under-structure to the plant, all make the plant more vulnerable to failures of structure that could lead to an environmental release of radiation, which is the ultimate disaster that everybody fears at this plant.

And so while the radiation leakage issue, and emissions issue, is not a day to day concern, you know, when the plant is operating optimally, if there isn't an aggressive strategy for preventive maintenance, that not just waits for something to happen, and then addresses it, but actually anticipates and replaces structures as they age, before they age.

This vulnerability will continue, you know, to be of great concern. That concludes my remarks, thank you.

SHC-10-5

MR. WALL: Good afternoon, I'm Roland Wall, I'm the Director for the Center for Environmental Policy at the Academy of Natural Sciences in Philadelphia.

On behalf of the Academy, I appreciate the opportunity to comment, specifically, on the environmental protection and restoration demonstrated in PSEG's estuary enhancement program.

Just a little context as to why the Philadelphia Museum is down here making these comments today. The Academy of Natural Sciences is the oldest natural history museum in North America but has also been engaged, for over 60 years, in research on ecological sciences, particularly on understanding human impacts on aquatic and estuarian systems.

It is in that role that we have had extensive research on the physical and biological characteristics of the Delaware estuary, including components of the estuary enhancement program. SHC-11-1

My comments today are based on observations of Academy scientists, particularly those of our senior fishery scientist, Dr. Rich Horowitz, who is unable to be here today.

The estuary enhancement program began in 1994. And, since that time, has been a large scale effort to restore and preserve portions of the Delaware estuary, in both New Jersey and Delaware, encompassing more than 32 square miles, as you heard earlier, it is the nation's largest privately-funded wetlands restoration project.

Restoration efforts have included the goal of replacing former salt hay farms, as you heard. And also to remove marshes that are dominated by the invasive phragmites, with saltcord grass dominated marsh.

This has required a substantial effort to control phragmites, and to change drainage patterns to foster topography and tidal flow typical of Delaware Bay salt marshes.

The Academy has studied many of these sites, prior to restoration and a number of them following restoration. Yes, the enhancement program has been successful in restoring typical salt marsh conditions at these sites, with most sites being targets for reduction of phragmites, and establishment of salt cordgrass.

At the remainder of sites where goals have been partially met, the estuary enhancement program continues to work to further improve marsh conditions.

The EP has also preserved open space, as at the bayside track. Among other improvements at the restored sites, tidal flow and development of tidal channels have increased, allowing for re-colonization of salt cordgrass and other species.

SHC-11-1

The restored marshes support large numbers of targeted fish species, as well as number of other fishes and invertebrates. These populations continue to -- excuse me, contribute to bay productivity, most notably, at the salt hay farms.

The restoration sites also provide important habitat for terrapins, birds, and mammals, and several of the sites are now part of New Jersey's Audubon designated important bird areas.

SHC-11-1

In addition to ecological restoration, the enhancement program has developed increased opportunities for human use and experience, to interact with the estuary.

Public use areas were designed to meet the general education, public access, and ecotourism interest of each community hosting an EEP site.

This has included improved access to many of the sites by land and water, with boat access and parking areas, in turn, supporting extensive recreational activities.

The public use areas have become important settings for numerous formal and informal educational programs. The restored areas have also become significant research sites, and research by EEP, and other organizations, including the Academy, has advanced our knowledge of tidal marsh ecology.

SHC-11-2

The basic restoration activities, particularly controlling phragmites and fostering development of tidal marsh topography and hydrology, have advanced the field of ecological restoration.

The ecological engineering technique of forming primary channels, and then using estuarian processes to further develop channels and topography, is especially notable.

And in that way the estuarian enhancement program does provide an important model for marshland restoration. PSEG has also installed fish passage structures at dams in Delaware and New Jersey.

These fish ladders have established river herring spawning in nursery areas, and several impoundments, increasing bay-wide populations of these species.

PSEG has continued to conduct monitoring programs of Delaware fish populations, which greatly increase our knowledge of Delaware Bay fisheries.

To conclude, the Academy would like to commend PSEG on its demonstrated initiative, and long-term commitment to restoring the critical wetlands of the Delaware estuary.

The estuary enhancement program has had numerous positive impacts on the ecology and biodiversity of the region,

SHC-11-3

and has made important contributions to the recreational and educational opportunities available to local communities.

The scale and scope of this effort has supported large scale scientific research, has improved our understanding of the process of environmental restoration.

The Academy of Natural Sciences has been pleased to have the opportunity to participate in, and to contribute, to our scientific expertise to this project. Thank you for the opportunity to speak on this.

SHC-11-3

MS. ACTON: Good evening. My name is Julie Acton, I'm a Salem County Freeholder. For those who do not live in New Jersey, I'm equal to a county commissioner. New Jersey is the only state to have freeholders.

I am also a member of the Dupont Advisory Committee. I am a volunteer for Meals on Wheels, and United Way. I'm a member of the Salem Community College, the Salem County Vocational Technical Advisory Board, and I'm very involved in my community.

So I pretty much have the pulse of the community at my fingertips. I am coming before you, this evening, to let you know that PSEG Nuclear is a valuable asset to our county. SHC-12-1

Not only are they a great community partner, but they are the county's largest employer. A majority of their employees are local residents, who live in our community.

In tough economic times PSEG Nuclear provides an example of integrity and commitment to positive growth that we all need to see. SHC-12-2

PSEG Nuclear takes a very proactive role in developing positive relationships with members of the Salem County community, whether it is providing funding and support to local community groups, or attending their events.

They are always demonstrating their commitment to Salem County. And they acknowledge our proud heritage, and recognize our bright future. We understand the hesitation of those within, and surrounding our county, towards PSEG Nuclear.

Their concern regarding safety and plant performance are valid. However, PSEG Nuclear has consistently demonstrated its commitment to safety and excellence through proper planning and transparency.

As a life-long resident of Salem County, and having raised my children here, I feel safe around the power plant. We have not seen any adverse impact to our environment, or our community.

I wholeheartedly support PSEG Nuclear and their license renewal for their Salem and Hope Creek stations. Thank you very much for your time.

SHC-12-3

MS. BERRYHILL: Well, this is a little different. My name is Frieda Berryhill, I'm from Wilmington, Delaware. I have been involved with Salem before it was licensed to operate, for the simple reason that Delmarva Power and Light, at the time, also planned to build a nuclear power plant right across the river from here, which would have made this area the largest nuclear complex in the world.

I was an intervenor, a case I couldn't lose, because they ordered a high temperature gas-cooled reactor, and you know what happened to that.

I'm very concerned about this.

I attended many hearings on the subject, ever since 1970. These plants should never have gotten a building permit. Upon examining the documents I found, to my shock, clearly described in detail, on the large map, the soil condition of artificial island. SHC-13-1

You see, there was no land here. It is called Artificial Island, because the island is built from dredgings of the Delaware River. And in the documents you will find that the borings of 35 feet are essentially nothing but mud and sand.

The next 35 feet are gravel and sand. The last 35 feet are described as Vincentown Formation, which is a different kind of gravel and sand. Borings up to 100 feet have not revealed rock bottom.

There is no rock bottom under these plants. The spent fuel pools, the auxiliary buildings, all of it, is sitting perched on cement pilings, I call them stilts, going 75 feet into the mud. And that is what is holding these plants up.

Now I have with me pictures of toppled buildings that have simply collapsed with the pilings still sticking to them. And I am deeply concerned to have a fourth reactor on that island.

SHC-13-1

Liquefaction is discussed in the documents. Liquefaction is the phenomenon when there is an earthquake, not a major earthquake, the sand is liquefies, and the building -- the hundreds of examples all over the world, where you can find that.

And you can find some of it even on Google. And I have made statements to that effect before the Delaware House Energy Committee, and other agencies. It doesn't seem to really matter what citizens say.

Yes, there was an earthquake up in Morris County. It was, actually, quite sizeable. But there is an earthquake fault, also, on the Delaware River. And, really, it scares me to think that it is only a matter of time, really, that an earthquake could happen here.

SHC-13-2

The Morris earthquake threw people out of the house, they thought there was a big explosion somewhere. It was not just a minor shaking or rattling.

Now, as to what could happen, I would like to just go back to the Rasmussen report, which was produced in 1970, as to the safety of nuclear power plants.

That wasn't satisfactory, so they commissioned another report in 1985, called "Consequences of Reactor Accident", called the "Crack Report". To just -- the numbers are just staggering.

The Crack Report for Salem reads as follows: Early peak fatalities, 100,000 Salem, 100,000 Salem 2. Early peak injuries, 70,000 for Salem 1, 75,000 for Salem 2.

Peak cancer deaths, Salem 1 40,000, Salem 2, 40,000. Damages, Salem 1, 140 billion, Salem 2, 135 billion. This is not fantasy, this is the government report.

SHC-13-2

I would like to interject, recently I wrote an article as to the soil conditions of this thing. And in that article I mentioned the Price-Anderson Act, that nuclear power plants could never be built without the protection of the Price-Anderson Act.

And some gentleman from the NRC felt compelled to write an answer to the local Wilmington paper saying, we don't

SHC-13-3

depend on the Price-Anderson Act, we have 9 billion dollars in reserve for whatever damages we cause. It makes me laugh, because there is no comparison to the damages that could be caused. Nine billion dollars is pocket change.

SHC-13-3

Clearly this plant should have never received a building permit, and surely it should not receive a license to operate for another 20 years. They were originally licensed for 40 years.

SHC-13-4

You are dealing with embrittlement, and all sorts of problems with that. There was a reason for it. Now, also, actually these plants were operating against the law, with more than three billion fish killed, annually, from the Delaware River.

And anything under three inches is taken up through the intake structure. The NEPA Act, which you have mentioned, which was passed in 1969, was passed just because this kind of damage.

On December 18th, 2001, Congress allowed these once-through cooling systems to continue as long as they restored the fish killed. Now, I saw that you had a display back there about that Habitation Restoration Act of 2001. But are you really raising fish?

SHC-13-5

Twenty-thousand tons of poison were spread to kill the phragmite. You can't kill that phragmite. I looked at the picture that you had back there, that phragmite keeps coming up. How many tons of poisons are you going to spray over there? Now, I was just told, a while ago, that you are replacing the fish. I would like to know how many fish that you are replacing, and what the story is on that.

SHC-13-5

Incredibly, though, that PSEG announced that it planned to spend another 50 million between 2007 and 2011 to explore the potential to construct a new reactor on the island, a fourth reactor. I think not.

I would like to ask a few questions, if I may. Nine billion dollars somewhere in the reserve. Can anybody, at the NRC, tell me who is holding this nine billion dollars?

I have a letter written to the editor, don't worry about Price-Anderson, we have nine billion dollars.

FACILITATOR BURTON: Ms. Berryhill, unfortunately we don't have the NRC staff here who would really be qualified to answer your question.

MS. BERRYHILL: Who would have that nine billion? Well, I will see if I can find out another way.

SHC-13-6

Has the company made any request for dry-cask storage?

SHC-13-7

FACILITATOR BURTON: Again, we really do not have the subject matter experts here to answer that question.

MS. BERRYHILL: All right.

FACILITATOR BURTON: You have one more question? SHC-13-7

MS. BERRYHILL: Yes, I do. With Yucca Mountain canceled you will have to, eventually, go the dry cask storage, I just want to know how soon, or whether you have made any plans, and who is producing them. You don't know that? Okay.

Now, you made a great deal about respecting public input. You had 20 license renewals approved now. None have been refused. I just wonder how much public input has really worked in these cases. None have been disapproved.

And some of them, by my estimate, should not have been approved. I have been to the NRC reading room in Washington, and there are records of every plant in there. Does Salem County have SHC-13-8 as complete a file as I would find it at the NRC reading room? Salem County library?

Everything is in there?

MR. ASHLEY: The application is at the library.

FACILITATOR BURTON: Hang on a second, let me give you the microphone here.

MR. ASHLEY: The license renewal application is at the Salem Library. But all the other documents are at the reading room at the NRC.

MS. BERRYHILL: At the reading room at the Nuclear Regulatory Commission, okay, thank you very much. SHC-13-8

MS. WILLING: Hi, my name is Nancy Willing, and I am from Newark, Delaware. I'm a life-long Delawarean. While I have never held elective office, I thought I would respond to Ms. Acton, by maybe saying some of my civic responsibilities as well.

But my dad was a plant manager for the plant here in New Jersey. Growing up he took the ferry in the '50, and got the bridge when it was built, the second bridge.

As a citizen of Newcastle County, I formed up the Friends of Historic Glasgow, interested in preserving historic battle sites. I have been on the board of W3R, Washington Rainbow Route. I was recently on the Board of the Civic League for Newcastle County.

And I'm also a Director of the Board of the Community Center in Wilmington, on the east side of Wilmington. So I have a variety of interests.

I've also ended up in frustration, from what a citizen can do, I ended up writing a political blog. So I also now write the Delaware Way blog with daily input. And I have written about -- Frieda is a contributor to the blog. So a lot of that is googable. And we try to keep the information out there.

I was at the 2009 emergency evacuation public hearing, here in New Jersey. And it was an interesting meeting for me SHC-14-1 because although Delaware is at risk, or in the 50 mile radius, we don't get this kind of attention, we don't have public hearings.

And I imagine that -- I was told, as I got here today, that some feelers went out to see if Delaware wanted to have a meeting similar to this, and it was not -- that didn't happen.

But that the emergency evacuation public meeting the state held, I didn't -- well, I will just go right to this. I

SHC-14-1

don't agree with the renewal of the 20 year licenses for the 40 year old structures that exist here today.

I don't think it is a wise and reasonable choice for the citizens. We do enjoy the energy that comes out of them, but we also have to expect to live our full lives here in this area.

A 40 year life span pretty much says it all, it is a 40 year life span, and the thought of another 20 year service from the Salem and Hope Creek structures seems to be asking too much, and offering uncertainty and trepidation to the public.

With age come leaks and cracks. The life span of potential contamination isn't worth that bargain, in my view.

SHC-14-2

While speaking with the state official from the Bureau of Nuclear Energy at the New Jersey, before the evaluation hearing had started I asked about having heard that Salem was built on swamp land.

SHC-14-3

And the gentleman, whose name I don't have here, he said of course not, and he proceeded to claim that the pilings went on through the sand, and gravel on Artificial Island, and were drilled securely into the bedrock.

So that was the opinion stated at that meeting, to me, by an official from the Bureau of Nuclear Energy here in New Jersey. So I took the question to the record, when I had a chance to speak, and formally ask the question, about Artificial Island structures, do they actually secure into bedrock, or don't they?

Because Frieda Berryhill had told me that in her investigations, that they had not. So I asked, for the record, and the officials promised me that they would investigate that discrepancy, and give it back to me in writing, which they never did, I never got anything from them. SHC-14-3

My concern was based on having heard that yet one more unit was planned to be constructed at the Salem complex. For the structures to be floating on a bed of gravel, and sand, and the result of a significant earthquake, six or seven on the Richter scale, would mean that the base of the structures, containing this nuclear material, would likely experience liquefaction, which Frieda got into a little bit.

That is the changing from compression of the earthquake, of the gravel and sand mix, into a jelly-like material. Liquefaction of the ground underneath causes structures to tip, slide, collapse, and otherwise break apart.

It was an unhappy coincidence that the evacuation hearing was on the same day as the earthquake. So it was an interesting experience. Another earthquake was centered a few miles away from the Salem plant.

And although it wasn't more than maybe two on the Richter scale, I'm not sure what it was, it isn't unheard of to think that we would have a more significant earthquake. The officials told me, that day, that the structures are built to withstand up to six or so on the Richter scale.

SHC-14-3

But would that prevent a significant earthquake, maybe not up to that, would that prevent the leaks and cracks of an aging plant that is floating on a bed of gravel and sand, so to speak, should another earthquake occur.

So the scope of the licensing process, here today, I think should be investigating that these are drilled into bed rock, that they are subject to liquefaction, and that would the aging of structures, brittle, -- would the aging, basically, have an impact on potential earthquake activity and contamination of the environment?

And I think that is, hopefully that would be in your scope, some serious study of that. So, thanks. SHC-14-3

MS. BEISTLINE: Hello everyone, good evening. My name is Monica Baseline, I work as a chemical systems engineer at Salem Generating Station. I'm here tonight representing NAYGN, which is the North American Young Generation of Nuclear.

This group unites young professionals who believe in nuclear science and technology, and show the passion for the field. Within this chapter I'm our environmental committee chair, and I enjoy spending my weekends camping, hiking, biking, and my favorite, rock climbing.

I graduated with a chemical engineering degree, which gave me a choice of fields after graduation. After much deliberation and interviewing, I narrowed these choices down to two industries, petroleum refining, and nuclear power. SHC-15-1

I remember, specifically, at dinner during the interviewing process, for refining jobs, about your ethics matching your company's ethics. Without this you can't ensure happiness and the ability to be passionate about your job.

I saw our country's dependence on fossil fuels diminishing, and I was not secure in my future, in the petroleum industry. I wanted to make sure that I worked for a company that I did not believe had a negative impact on the environment I enjoyed on the weekends.

I worked with PSEG for more than a year and within this year I have received less than three millirem of dose. This is about half as much as you would receive on a cross-country flight, or a dental x-ray.

I believe nuclear is the future of safe and reliable power. And I believe we need support from the public to explore things such as interim waste storage, and reprocessing. SHC-15-1

I'm happy to say I love my job, and I'm proud to be with PSEG. Thank you.

MR. GRENIER: I'm here, I have a couple of comments. One is the local Woodstown Borough Councilman, and then another as a resident.

I've been a councilman for a couple of years, and I'd like to say on behalf of the borough, thank PSEG for their leadership in our community, community activities.

Also their stewardship toward the environment, from the estuary enhancement program, and Mr. Fricker spoke a little bit about their lack of greenhouse gases and how environmentally friendly our nuclear facility is.

And also, as Mr. Hassler spoke of, creation of a good number of well-paying, long-term jobs. It is not a project that is just here to build a big road, and then it goes away. So the jobs are here to stay for long term.

SHC-16-1

As a resident I would like to say that I've been here for 15 years, as long as I have worked at the island. And my wife Patty and I are raising three kids in town.

We do seeing eye puppies, we are in scouts, we are in our local church, try to teach our kids how to be active in the community, something that PSEG encourages all of their employees to do through United Way and other programs.

And they give a good amount of money into the county to promote other activities like that. As I said, I have been employed with PSEG for 15 years, in chemistry, radiation protection, and now in training.

And I have, first-hand, witnessed what we do at the plant through our sampling, and our stewardship to the community through our emergency plan activities, and protection of the public.

So I would ask that the NRC consider the plant life extension request, and I strongly encourage that they accept it, move forward with it, and look at the communities that are around here, and the municipalities, and how they all embrace the plant, and the PSEG facility, supportive of it.

I don't know of any municipalities that are against the site. And I look forward to pursuing, to come to future meetings in the pursuit of the plant life extensions, and also the possibility of a fourth reactor. Thank you.

SHC-16-1

SIERRA CLUB
FOUNDED 1892

New Jersey Chapter
145 West Hanover Street
Trenton, NJ 08618

October 12, 2009

U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Commissioners Jaczko, Klein and Svinicki,

Enclosed is a resolution, passed by the New Jersey Chapter of Sierra, requesting that the Nuclear Regulatory Commission and the New Jersey Department of Environmental Protection require PSE&G to erect cooling towers at the Salem Nuclear Plants as a requirement to renewing the operating licenses. The Executive Board of the New Jersey Chapter is making this request on behalf of over 20,000 members of the New Jersey Chapter. SHC-17-1

Thank you for your consideration in this very important matter.

Very truly yours,

Gina Carola

Chair, West Jersey Group
New Jersey Chapter of Sierra

printed on recycled paper

SIERRA CLUB
FOUNDED 1892

New Jersey Chapter
145 W. Hanover Street
Trenton, NJ 08618
TEL: (609) 656-7612 FAX: (609) 656-7618
www.newjersey.sierraclub.org

Resolution Requesting that the NJDEP and the NRC Require PSE&G to Erect Cooling Towers at the Salem Nuclear Plants

WHEREAS, the Salem nuclear power plants do not have a closed cooling system (cooling towers); and

WHEREAS, the plants use over 3 billion gallons of Delaware Bay water every day for cooling, causing billions of fish and other marine life to be slaughtered every year as they are ground up in the intake valves; and

WHEREAS, the slaughter of the fish severely impacts the ecosystem of the Delaware River Estuary by taking billions of smaller bait fish per year out of the food chain for larger fish and birds; and

WHEREAS, the billions of game and commercial fish fry that are ground up and destroyed in the intake valves severely impacts both the recreational and the commercial fishing industry; and

WHEREAS, jobs are dependent on both the recreational and the commercial fishing industry.

NOW THEREFORE, BE IT RESOLVED, that the New Jersey Chapter of the Sierra Club requests that the New Jersey Department of Environmental Protection and the Nuclear Regulatory Commission require that PSE&G build a closed cooling system, such as cooling towers, for Salem Units 1 and 2, which would eliminate 90 to 95 percent of the fish slaughter.

BE IT FURTHER RESOLVED, that copies of this resolution be sent to the New Jersey Department of Environmental Protection and the Nuclear Regulatory Commission.

SHC-17-1

Dated: September 12, 2009

SIERRA CLUB, NEW JERSEY CHAPTER

Kenneth R. Johanson, Chapter Chair

Charles Eccleston

From: Greenhill, John [mailto:John.Greenhill@dhs.gov]
Sent: Wednesday, November 04, 2009 7:18 PM
To: Eccleston, Charles
Subject: Salem and Hope Creek Nuclear Plants 20 year license extensions
Importance: High

Dear Mr. Eccleston,

I am unable to attend the hearings on 11/5/09 but would like to submit the following questions.

There were incidents on 3/13/1989 and 9/19/1989 at the Salem 1and 2 Nuclear Plants sites when geomagnetic storms caused damage to the single phase, generator step-up transformers which caused them to be taken out of service.

The damages were due to geomagnetically induced currents caused by the geomagnetic storms.

Questions:

1. Is there a publically available report that describes these incidents?
2. What was the magnitude of the currents that caused the damage?
3. How long did the damaging currents persist?
4. What was the protective relay system in place at that time such as the IEEE Std C37.91-1985?
5. Where there any modifications to the transformer protective system put into effect?
6. How will the step-up transformers at Salem and Hope Creek sites be protected if a super geomagnetic storm (10 times the size of the 1989 storms) occurs during the 20 year extension?
7. Do the sites have spare step-up transformers?

SHC-18-1

John D. Greenhill P.E.
Department of Energy
National Communications System
Department of Homeland Security
E-mail: john.greenhill@dhs.gov
Phone: 703-235-5538

2

Eccleston, Charles

From: Greenhill, John [John.Greenhill@dhs.gov]
Sent: Monday, November 09, 2009 3:46 PM
To: Eccleston, Charles
Subject: RE: Salem and Hope Creek Nuclear Plants 20 year license extensions

Charles,
Many thanks for this information.
An initial cursory look shows a possible problem with this draft EIS when one examines table 5-2

Table 5-2. TMI-1 Internal Events Core Damage Frequency

Initiating Event	CDF (Per Year)	% Contribution to CDF
Loss of Offsite Power	7.73×10^{-6}	32.6
Transients	5.80×10^{-6}	24.5
Small and Very Small LOCA	4.66×10^{-6}	19.7
Loss of Nuclear Service River Water	3.67×10^{-6}	15.5
Steam Generator Tube Rupture	9.93×10^{-7}	4.2
Internal Floods	4.50×10^{-7}	1.9
Large and Medium LOCA	2.06×10^{-7}	< 1
ISLOCA	1.80×10^{-7}	<1
Total CDF (internal events)	**2.37×10^{-5}**	**100**

The probability of a super solar storm of the 1859 or 1921 size is about 1/100 years or 1 %/year. This size storm leads to a continental long term (many months) grid outage because of damage to all the U.S. step-up transformers similar to the damage that occurred at Salem New Jersey in 1989during a fairly mild solar storm. With such an outage the emergency generators (that drive the cooling pumps) fuel supply would run out and could not be replaced because the commercial fuel suppliers would be out of fuel as well. Without fuel for the the cooling pumps, the core damage frequency (CDF) appears to be several orders larger that the CDF given in the table 5-2. Perhaps s solar storm initiating event should be included in all the final EIS documents. SHC-18-2

John D. Greenhill P.E.
Department of Energy
National Communications System
Department of Homeland Security
E-mail: john.greenhill@dhs.gov
Phone: 703-235-5538

From: prvs=557c0bb17=Charles.Eccleston@nrc.gov [mailto:prvs=557c0bb17=Charles.Eccleston@nrc.gov] **On Behalf Of** Eccleston, Charles
Sent: Monday, November 09, 2009 3:02 PM
To: Greenhill, John
Subject: RE: Salem and Hope Creek Nuclear Plants 20 year license extensions

John,

Here is a recent draft EIS. You will have to open it as a read-only file. Check out Chapter 5.

1

Eccleston, Charles

From: Greenhill, John [John.Greenhill@dhs.gov]
Sent: Saturday, November 21, 2009 9:24 PM
To: SalemEIS; HopeCreek@nrc.gov
Cc: Eccleston, Charles; Warren Udy
Subject: Salem and Hope Creek Nuclear Plants 20 year license extensions

Dears Sirs

There were incidents on 3/13/1989 and 9/19/1989 at the Salem 1,2and Hope Creek nuclear plants sites when geomagnetic storms caused damage to the single phase, generator step-up transformers which caused them to be taken out of service.

The damage was due to geomagnetically induced currents (GIC) caused by the geomagnetic storms.

Questions:
1. Is there a publically available report that describes these incidents?
2. What was the magnitude of the currents that caused the damage?
3. How long did the damaging currents persist?
4. What was the protective relay system in place at that time such as the IEEE Std C37.91-1985?
5. Where there any modifications to the transformer protective system put into effect?
6. How will the step-up transformers at Salem and Hope Creek sites be protected if a super geomagnetic storm (10 times the size of the 1989 storms) occurs during the 20 year extension? The next solar maximum is expected 2013-2014.
7. Do the sites have spare step-up transformers?

The TMI Generic Environmental Impact Statement for License (NUREG-1437 Supplement 37) table 5-2 shows the following

Table 5-2. TMI-1 Internal Events Core Damage Frequency

Initiating Event	CDF (Per Year)	% Contribution to CDF
Loss of Offsite Power	7.73×10^{-6}	32.6
Transients	5.80×10^{-6}	24.5
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Internal Floods	4.50×10^{-7}	1.9
Large and Medium LOCA	2.06×10^{-7}	< 1
ISLOCA	1.80×10^{-7}	<1
Total CDF (internal events)	$\mathbf{2.37 \times 10^{-5}}$	**100**

The probability of a super solar storm of the 1859 or 1921 size is about 1/100 years or 1 %/year. This size storm could lead to a continental wide, long term (many months) outage of the bulk power grid because of damage to all the U.S. step-up transformers. This damaged would be similar to the damage that occurred at Salem New Jersey in 1989 during a fairly mild solar storm. With such an outage, the emergency generators (that drive the cooling pumps) fuel supply could run out and may not be replaced because all the commercial fuel suppliers would be out of fuel as well due to the failure of the electrical pumps. Without fuel for the cooling pumps, the core damage frequency (CDF) appears to be several orders larger that the CDF given in the table 5-2. Perhaps s solar storm initiating event should be included in all the final EIS documents including the Salem and Hope Creek..

SHC-18-3

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1

John D. Greenhill P.E.
Department of Energy
National Communications System
Department of Homeland Security
E-mail: john.greenhill@dhs.gov
Phone: 703-235-5538

2

Eccleston, Charles

From: Frieda Berryhill [frieda302@comcast.net]
Sent: Saturday, November 07, 2009 7:25 PM
To: Eccleston, Charles
Cc: Goodman Sid
Subject: Woodstown N.J.

Dear Mr. Eccleston:
It was truly a pleasure meeting you . The documents you wanted are:

Mr. Goodmans statement to the NRC September 7, 2009
Mr. Goodmans statement to the New Jersey Public Advocate September 23, 09
5 Page letter from the NRC August 24. 2009 Mr. B A Boger fro Eric J. Leeds, Director, Office of Nuclear Reactor Regulation
Essentially confirming the soil condition of Artificial Island and the existence of the 70 ft pilings on which the plants are perched. But you can find it in the document room as I did.

Since these are essentially Mr. Goodmans statements I thought it to be more appropriate for him to send them, I have asked Mr. Goodman to do so.

Mr. Sid Goodman
Mahwah, N.J. 07430
Tel# 327 5158

Sincerely

Frieda Berryhill

1

158 Grandview Lane

Mahwah, NJ 07430

September 7, 2009

Donnie Ashley @ the Nuclear Regulatory Commission

Subject: Comment on License Renewal for the Salem and Hope Creek Nuclear Power Plants.

To renew the licenses for these nuclear plants represents extreme neglect of the public safety and welfare. It was incredibly poor judgment that these plants were built on "Artificial Island" in the first place. These plants should be shut down, with operation not allowed to continue, much less have their operation greatly extended. Incredibly, PSE&G is considering putting another nuclear plant on this island in this earthquake prone region. For shame!

None of the nuclear plants are built on solid rock. They are on filled in land. The letter I received from Bruce A. Boger (August 24) confirmed that these plants are not on solid rock. They rest on compacted engineering fill material or concrete, which have a depth of approximately 70 feet. Concrete pilings are used. The NRC presumes that this will enable them to resist the worst assault that an earthquake can deliver. This is wishful thinking, rather than common sense. SHC-19-1

Not only that, but deceitful testimony has been given in support of the environmental impact of the existing nuclear plants. The statement for renewal states that the existing plants had no adverse effects on the Delaware Estuary. In fact, Salem kills 3 billion fish annually. Environmental expert Robert F. Kennedy Jr. sued the EPA in 1993. He revealed that Salem alone killed more than 3 billion Delaware River fish each year, according to the plant's own consultant. Fish kills are illegal and represent criminal acts. SHC-19-2

What can happen from building on unstable land was exemplified in Shanghai, China.

At around 5:30 AM on June 27, 2009 an unoccupied building, still under construction at Lianhuanan Road in the Mining district of Shanghai City toppled.

Just before the toppling, there were reports of cracks on the flood-prevention wall near the buildings and "special geological conditions" in the water bank area. SHC-19-3

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In Japan, seven reactors at the *Kashiwazi-Kariwa* nuclear power plant in Japan were shut down due to an earthquake, fire and nuclear leak. People were killed and injured by the 6.8 magnitude quake, which struck in July, 2007. A new fire at the still shut down plant occurred in March, 2009. 600,000 residents signed a petition opposing restart of the plant.

The arrogance of building nuclear plants in an earthquake prone area is almost unbelievable. Believe it! This arrogance is also invested in other Nuclear Regulatory Commission rules.

SHC-19-3

The NRC is still satisfied with a mere ten-mile evacuation zone around a nuke when poisons from Three Mile Island were blown hundreds of miles. Poisons from Chernobyl were blown around the world? This satisfaction is idiotic.

The NRC continues support for the Price Anderson Act. This federal law limits liability of a disaster to a microscopic fraction of the potential damage which will be incurred? This Act reduces concerns of operating utilities, a very risky effect. This federal law abolishes the property rights of Americans in order to protect the property rights of nuclear plant owners. This atrociously unfair law is nothing less than Fascist.

The NRC continues to support the distribution of potassium iodide pills as an assurance that no one will be harmed from a disaster? These pills only protect against radioactive iodine. The pills must be taken immediately and continue to be used for as long as radioactive iodine lingers in the environment. The pills do nothing to protect against all of the other radioactive poisons, which are released. This is no real assurance to anyone who is informed.

The NRC continues to support ridiculously inadequate evacuation plans following a fuming meltdown at a nuke.

SHC-19-4

The record of the NRC, including other shameful rulings, has earned it the reputation that the initials **NRC** stand for **Nobody Really Cares**. The automatic relicensing of old and crumbling nuclear plants by the NRC emphasizes the truth of that reputation.

All of the above represents technological prostitution. At least girls of the night are honest in what they do.

Cut the arrogance! Cut the stupidity! Start protecting Americans. An anything for profits paradigm has brought this great nation to the brink of destruction. The NRC's further actions can allow the final destructive blow. It is unpatriotic.

Very truly yours,

S J Goodman, PE

Sidney J. Goodman, P.E., M.S.M.E. Professional Engineer NJ License 15326.

Home phone (201) 327-5158

Author of "Asleep at the Geiger Counter" - Blue Dolphin Publishing Inc.

1

Toppled Building lying flat on the ground.

Pilings that were supposed to assure that the building was stable.

Three New Jersey nuclear power plants are built on unstable ground. These are the Salem I, Salem II, and the Hope Creek plants.

They are on *Artificial Island* in the *Delaware River*. It was named "Artificial" because it was man-made with filled in land. There is a swamp on one side of the island with the river on the other side. There is no solid rock underneath. Borings were made up to 100 feet deep. No rock was found. The reactors are built on pilings similar to the pilings shown in the collapsed Shanghai City building.

See the concrete pilings of the building that collapsed.

Like so many nuclear facilities, these three nukes are close to an earthquake fault. This fault rumbled on February 3, 2009. The noise of geological shocks in February, terrified people in Morris County who thought the shocks were explosions as reported by The Star Ledger,

The Morris County (NJ) quake had an intensity of 3.0. That was a small event according to the *US Geological Survey*. But much more intense earthquakes are due. Earthquakes may occur a few times a year in New Jersey. Some are so small that they are hardly noticed. A biggie can happen in a hundred years or tomorrow.

From: wdunn302@comcast.net
Sent: Thursday, September 03, 2009 11:55 AM
To: Ashley, Donnie
Cc: Bill Dunn
Subject: Comments On Salem and Hope Creek License Application

William R Dunn
Elsmere, Delaware
September 3, 2009

Donnie Ashley, Project Manager
Division of License Renewal
Office o Nuclear Reactor Regulation
U.S. Nuclear regulatory Commission, Mail Stop 011-F1
Washington, DC 20555
301-415-3191

Reference:

LICENSE RENEWAL APPLICATION
Hope Creek Generating Station
Facility Operating License No. NPF-57

LICENSE RENEWAL APPLICATION
Salem Nuclear Generating Station
Unit 1 Facility Operating License No. DPR-70
Unit 2 Facility Operating License No. DPR-75

Dear Mr. Ashely,

As a former management consultant for a number of EPA 208 Water Quality Area-Wide pollution control programs, I am very much interested in reviewing projects that may have a significant impact on the environment as well as the need to sustain a reliable physical infrastructure that supports our economy and standard of living. Having also worked in Haiti as a consultant, I experienced first hand routine electrical blackouts, an unreliable turn-of-the-ninetieth century telephone system, and other infrastructure shortcomings for drinking water and transportation. We take the safety and reliable delivery of these type services for granted in the United States. Electrical generation is the critical infrastructure component that the rest of the economy depends.

I have reviewed the applications for both the Hope Creek and Salem nuclear facilities and would make the following comments:

<u>Hope Creek and Salem Applications</u>

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The environmental impact appears to be minimal for granting an extension of the facilities license and there is certainly a justified need to upgrade portions of nuclear power generating operations to replace aging equipment that will improve the power generating capabilities and mitigate safety issues of an aging plant.

Secondly, nuclear power does not produce greenhouse gas (CO2) and consequently would be a more attractive alternative to burning coal or natural gas.

Third, based on my research on the emerging nuclear fusion technology, the disposal of nuclear waste will be one day be safely transmuted to useful isotopes. Nuclear fusion and fission will be paired to provide almost unlimited power without the issue of residual radioactivity.

Fourth, the option of purchasing more electricity by de-commissioning these facilities will likely require modifying and building additional transmission lines to support this option. This will have a far more deleterious affect on the environment and communities where these lines will be constructed that continuing to operating these nuclear facilities. Furthermore, importing electricity will likely originate from either coal or gas fired units that produced the greenhouse gases CO2 (and other pollutants) as compared to nuclear power that generates zero greenhouse gas.

<u>Recommendation</u>

I endorse the granting of these facilities a license extension for the aforementioned reasons and would further recommend that these sites be replaced with new state of the art nuclear power plants that would have additional electrical generating capacity. Nuclear power has proven to be a reliable and cost-effective source of electricity and would provide the basis for pairing with nuclear fusion technology in approximately 20 years that would meet our countries energy needs as well as safeguard our environment.

Please feel free to contact me if you require additional information or comment.

Very truly yours,

William R Dunn

Hearing Docket

From: dorickards@aol.com
Sent: Saturday, October 24, 2009 2:26 PM
To: Docket, Hearing
Cc: OGCMailCenter Resource
Subject: hearing on Salem/Hope Creek nuclear plant

DOCKETED
USNRC

October 24, 2010 (2:26 p.m.)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

Secretary of the Commission
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Attention: Rulemaking and Adjudications Staff:

Every Power Plant currently using intakes either for once through operations or to replenish water lost from evaporation should be required to partner with the most local municipality and pipe their treated wastewater to the power plant to eliminate intakes.

Intakes kill millions of fish annually and once through operations adversely modifies the environment surrounding the outflow area. Municipalities need to dispose of their treated wastewater and to pipe this affluent to a facility that can use it is a least expensive and obviously the most environmentally friendly method.

All power plants should upgrade to a cooling tower technology. If too much heat in generated to recycle the water, cooling units can be added to the outflow troughs to reduce the temperature of the water prior to reuse.

The kinetic energy available in cooling tower outflows can be tapped with UEK turbine technology to generate enough electricity to run cooling coil units. ENERGY RECOVERED = GOOD MANAGEMENT.

SHC-21-1

David O. Rickards
Instream Energy LLC
34612 Rickards Road
Frankford, DE 19945-3544
(302)539-9034 Ph
(302)537-2372 Fax

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LOWER ALLOWAYS CREEK TOWNSHIP
PO BOX 157
501 LOCUST ISLAND ROAD
HANCOCK'S BRIDGE, NEW JERSEY 08038
(856) 935-1549 ext #623 (856) 935-7666 Fax
lactwpclerk@yahoo.com

November 3, 2009

US Nuclear Regulatory Commission
Washington, DC

Re: PSEG Nuclear's License Renewal for Salem and Hope Creek Generating Stations

My name is Ellen B. Pompper, and I am the current Mayor of Lower Alloways Creek Township. We are the host municipality for PSEG Nuclear's Salem & Hope Creek stations. I have lived in Lower Alloways Creek Township for over 30 years and served on local government for 12 years, 5 of those years as Mayor.

While some may not want a nuclear plant in their backyard, we welcome PSEG Nuclear, who we consider a good friend and neighbor. PSEG is transparent and open with us. They are quick to call me and let me know of plant issues and news worthy items that affect us. Each Month, I and other Township Officials meet with PSEG Nuclear. We discuss plant operations and other points of interest that impact not only Salem and Hope Creek, but also our community.

As you know, nuclear is a clean source of energy. The plants produce a significant amount of electricity without emitting carbon dioxide and other greenhouse gases. SHC-22-1

Our community is dotted with farms that also have seen no environmental impact. PSEG has an extensive monitoring program that ensures the health and safety of the public especially those in Lower Alloways Creek.

I support the license renewal for Salem and Hope Creek another 20 years and ask that the NRC approve this life extension for these stations.

Thank You

Ellen B. Pompper

Ellen B. Pompper, Mayor Lower Alloways Creek Township

Ebp/rlc

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The UNPLUG SALEM Campaign
321 Barr Ave., Linwood NJ 08221
ncohen12@comcast.net
www.unplugsalem.org
609-335-8176

11/30/2009

To: Nuclear Regulatory Commission:

Comments for the environmental review of the relicensing of Hope Creek **Docket No. 50-354 License No. NPF-57 PSEG Nuclear, LLC**

The UNPLUG Salem Campaign is a network of organizations and individuals that act as a public health and nuclear safety watchdog for PSEG's three nuclear power plants.

This letter concerns the proposed relicensing of Hope Creek. We oppose extending the license of this nuclear plant. We also oppose the process by which decisions on relicensing are made. This process makes it virtually impossible for most individuals and many organizations to participate. In addition, because only certain issues are deemed acceptable by the NRC for submission as contentions, many issues of safety and health are not even looked at by NRC in making their decision. SHC-23-1

We also oppose relicensing a nuclear plant twenty years before its license is up for renewal.

If the NRC can give Oyster Creek a 20 year extension, even though that nuclear plant could not be built under today's standards, and is a meltdown waiting to happen, it is clear that the relicensing process for Hope Creek will be nothing more than paperwork and rubber stamping. SHC-23-2

However, it is important to put our concerns on the record, even though we do not expect NRC to act on any of them. SHC-23-3

Here are areas that NRC should look at and then deny Hope Creek a 20 year extension:

(1) Hope Creek has leaked hydrazine into the Delaware Bay. SHC-23-4

(2) The electrical system that connects Hope Creek to the grid is old and has had a SHC-23-5

number of failures, including transformer failures.

(3) PSEG has a spotty record when it comes to keeping diesel generators working. This is a concern because all three nuclear plants rely on diesel generators if offsite power is interrupted.

(4) PSEG has a serious Safety Conscious Work Environment (SCWE) and Safety Culture problem. This has been a chronic problem at all 3 of PSEG's plants, and continues to show up in NRC inspections under "cross-cutting issues of human performance". One key example at Hope Creek was the loss of 5000 gallons of cooling water, due to human error. This event could have escalated into a TMI-type of situation. SHC-23-5

(5) Hope Creek is vulnerable to a severe earthquake because Artificial Island is built on compacted mud, and its pilings do not reach bedrock. SHC-23-6

(6) Because Yucca Mountain, the national depository for spent nuclear fuel, will not be operative, Lower Alloways Creek will become, and actually is now, a long term nuclear waste dump, which violates the zoning board agreement between PSEG and Lower Alloways. SHC-23-7

(7) Hope Creek has buried pipes and electrical conduits that have not been inspected and, based on other nuclear plants, may be leaking tritium or in danger of electrical shorts happening. SHC-23-8

(8) The Evacuation Plan for Salem/Hope Creek is based on faulty assumptions and would not work under many scenarios, including a fast acting radiation release and multiple releases. Under worst case scenarios, thousands of people within the 10 and 50 mile zones would die from radiation exposure. SHC-23-9

(9) Hope Creek emits continual amounts of low level radiation and radionuclides, which contribute to the cancer cases and immune system disorders in the 50 mile zone around Artificial Island. SHC-23-10

(10) Hope Creek remains a prime terrorist target, and there are many ways terrorists could prevail, only one of which will I list here. SHC-23-11

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(11) Hope Creek's Spent Fuel Pool is above ground and not protected by containment. It is a prime terrorists target. If the water in the Pool drains out, there would be massive radiation releases. SHC-23-11

(12) If NRC approves the relicensing of Hope Creek, the people of South Jersey and Delaware will become unwitting guinea pigs in NRC's grand experiment to find out if aging nuclear plants actually can last another 20 years or not.

What should be done:

Hope Creek should be decommissioned at the end of its 40 year license. Affected employees should be relocated and retrained by PSEG. Artificial Island should be turned into a wind power and solar power "park" to produce some of the electrical energy formerly produced by the nuclear plants. SHC-23-12

Sincerely,

Norm Cohen
Coordinator, The UNPLUG Salem Campaign

emailed to NRC 11/29/09

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A.3 References

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Appendix B

NEPA Issues for License Renewal of Nuclear Power Plants

B. NEPA Issues for License Renewal of Nuclear Power Plants

Table B-1. Summary of Issues and Findings. *This table is taken from Table B-1 in Appendix B, Subpart A, to 10 CFR Part 51. Data supporting this table are contained in NUREG-1437, Generic Environmental Impact Statement for License Renewal of Nuclear Plants. Throughout this report, "Generic" issues are also referred to as Category 1 issues, and "Site-specific" issues are also referred to as Category 2 issues.*

Issue	Type of Issue	Finding
Surface Water Quality, Hydrology, and Use		
Altered current patterns at intake and discharge structures	Generic	SMALL. Altered current patterns have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Altered salinity gradients	Generic	SMALL. Salinity gradients have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Altered thermal stratification of lakes	Generic	SMALL. Generally, lake stratification has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.
Temperature effects on sediment transport capacity	Generic	SMALL. These effects have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Scouring caused by discharged cooling water	Generic	SMALL. Scouring has not been found to be a problem at most operating nuclear power plants and has caused only localized effects at a few plants. It is not expected to be a problem during the license renewal term.
Eutrophication	Generic	SMALL. Eutrophication has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.
Discharge of chlorine or other biocides	Generic	SMALL. Effects are not a concern among regulatory and resource agencies, and are not expected to be a problem during the license renewal term.
Discharge of sanitary wastes and minor chemical spills	Generic	SMALL. Effects are readily controlled through NPDES permit and periodic modifications, if needed, and are not expected to be a problem during the license renewal term.

Issue	Type of Issue	Finding
Discharge of other metals in wastewater	Generic	SMALL. These discharges have not been found to be a problem at operating nuclear power plants with cooling-tower-based heat dissipation systems and have been satisfactorily mitigated at other plants. They are not expected to be a problem during the license renewal term.
Water use conflicts (plants with once-through cooling systems)	Generic	SMALL. These conflicts have not been found to be a problem at operating nuclear power plants with once-through heat dissipation systems.
Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	Site-specific	SMALL OR MODERATE. The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations. See § 51.53(c)(3)(ii)(A).
		Aquatic Ecology
Accumulation of contaminants in sediments or biota	Generic	SMALL. Accumulation of contaminants has been a concern at a few nuclear power plants but has been satisfactorily mitigated by replacing copper alloy condenser tubes with those of another metal. It is not expected to be a problem during the license renewal term.
Entrainment of phytoplankton and zooplankton	Generic	SMALL. Entrainment of phytoplankton and zooplankton has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.
Cold shock	Generic	SMALL. Cold shock has been satisfactorily mitigated at operating nuclear plants with once-through cooling systems, has not endangered fish populations or been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds, and is not expected to be a problem during the license renewal term.
Thermal plume barrier to migrating fish	Generic	SMALL. Thermal plumes have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Distribution of aquatic organisms	Generic	SMALL. Thermal discharge may have localized effects but is not expected to affect the larger geographical distribution of aquatic organisms.

Issue	Type of Issue	Finding
Premature emergence of aquatic insects	Generic	SMALL. Premature emergence has been found to be a localized effect at some operating nuclear power plants but has not been a problem and is not expected to be a problem during the license renewal term.
Gas supersaturation (gas bubble disease)	Generic	SMALL. Gas supersaturation was a concern at a small number of operating nuclear power plants with once-through cooling systems but has been satisfactorily mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.
Low dissolved oxygen in the discharge	Generic	SMALL. Low dissolved oxygen has been a concern at one nuclear power plant with a once-through cooling system but has been effectively mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.
Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	Generic	SMALL. These types of losses have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Stimulation of nuisance organisms (e.g., shipworms)	Generic	SMALL. Stimulation of nuisance organisms has been satisfactorily mitigated at the single nuclear power plant with a once-through cooling system where previously it was a problem. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)		
Entrainment of fish and shellfish in early life stages	Site-specific	SMALL, MODERATE, OR LARGE. The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid. See § 51.53(c)(3)(ii)(B).

Issue	Type of Issue	Finding
Impingement of fish and shellfish	Site-specific	SMALL, MODERATE, OR LARGE. The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. See § 51.53(c)(3)(ii)(B).
Heat shock	Site-specific	SMALL, MODERATE, OR LARGE. Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants. See § 51.53(c)(3)(ii)(B).
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)		
Entrainment of fish and shellfish in early life stages	Generic	SMALL. Entrainment of fish has not been found to be a problem at operating nuclear power plants with this type of cooling system and is not expected to be a problem during the license renewal term.
Impingement of fish and shellfish	Generic	SMALL. The impingement has not been found to be a problem at operating nuclear power plants with this type of cooling system and is not expected to be a problem during the license renewal term.
Heat shock	Generic	SMALL. Heat shock has not been found to be a problem at operating nuclear power plants with this type of cooling system and is not expected to be a problem during the license renewal term.
Ground Water Use and Quality		
Ground water use conflicts (potable and service water; plants that use <100 gpm)	Generic	SMALL. Plants using less than 100 gpm are not expected to cause any ground water use conflicts.
Ground water use conflicts (potable and service water, and dewatering plants that use >100 gpm)	Site-specific	SMALL, MODERATE, OR LARGE. Plants that use more than 100 gpm may cause ground water use conflicts with nearby ground water users. See § 51.53(c)(3)(ii)(C).
Ground water use conflicts (plants using cooling towers withdrawing make-up water from a small river)	Site-specific	SMALL, MODERATE, OR LARGE. Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other ground water or upstream surface water users come on line before the time of license renewal. See § 51.53(c)(3)(ii)(A).

Issue	Type of Issue	Finding
Ground water use conflicts (Ranney wells)	Site-specific	SMALL, MODERATE, OR LARGE. Ranney wells can result in potential ground water depression beyond the site boundary. Impacts of large ground water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal. See § 51.53(c)(3)(ii)(C).
Ground water quality degradation (Ranney wells)	Generic	SMALL. Ground water quality at river sites may be degraded by induced infiltration of poor-quality river water into an aquifer that supplies large quantities of reactor cooling water. However, the lower quality infiltrating water would not preclude the current uses of ground water and is not expected to be a problem during the license renewal term.
Ground water quality degradation (saltwater intrusion)	Generic	SMALL. Nuclear power plants do not contribute significantly to saltwater intrusion.
Ground water quality degradation (cooling ponds in salt marshes)	Generic	SMALL. Sites with closed-cycle cooling ponds may degrade ground water quality. Because water in salt marshes is brackish, this is not a concern for plants located in salt marshes.
Ground water quality degradation (cooling ponds at inland sites)	Site-specific	SMALL, MODERATE, OR LARGE. Sites with closed-cycle cooling ponds may degrade ground water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses. See § 51.53(c)(3)(ii)(D).
Terrestrial Ecology		
Cooling tower impacts on crops and ornamental vegetation	Generic	SMALL. Impacts from salt drift, icing, fogging, or increased humidity associated with cooling tower operation have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Cooling tower impacts on native plants	Generic	SMALL. Impacts from salt drift, icing, fogging, or increased humidity associated with cooling tower operation have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.
Bird collisions with cooling towers	Generic	SMALL. These collisions have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.

Issue	Type of Issue	Finding
Cooling pond impacts on terrestrial resources	Generic	SMALL. Impacts of cooling ponds on terrestrial ecological resources are considered to be of small significance at all sites.
Power line right of way management (cutting and herbicide application)	Generic	SMALL. The impacts of right-of-way maintenance on wildlife are expected to be of small significance at all sites.
Bird collisions with power lines	Generic	SMALL. Impacts are expected to be of small significance at all sites.
Impacts of electromagnetic fields on flora and fauna	Generic	SMALL. No significant impacts of electromagnetic fields on terrestrial flora and fauna have been identified. Such effects are not expected to be a problem during the license renewal term.
Floodplains and wetland on power line right of way	Generic	SMALL. Periodic vegetation control is necessary in forested wetlands underneath power lines and can be achieved with minimal damage to the wetland. No significant impact is expected at any nuclear power plant during the license renewal term.
Threatened and Endangered Species		
Threatened or endangered species	Site-specific	SMALL, MODERATE, OR LARGE. Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected. See § 51.53(c)(3)(ii)(E).
Air Quality		
Air quality effects of transmission lines	Generic	SMALL. Production of ozone and oxides of nitrogen is insignificant and does not contribute measurably to ambient levels of these gases.
Land Use		
Onsite land use	Generic	SMALL. Projected onsite land use changes required during refurbishment and the renewal period would be a small fraction of any nuclear power plant site and would involve land that is controlled by the applicant.
Power line right of way	Generic	SMALL. Ongoing use of power line right of ways would continue with no change in restrictions. The effects of these restrictions are of small significance.

Issue	Type of Issue	Finding
		Human Health
Microbiological organisms (occupational health)	Generic	SMALL. Occupational health impacts are expected to be controlled by continued application of accepted industrial hygiene practices to minimize worker exposures.
Microbiological organisms (public health)(plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	Site-specific	SMALL, MODERATE, OR LARGE. These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically. See § 51.53(c)(3)(ii)(G).
Noise	Generic	SMALL. Noise has not been found to be a problem at operating plants and is not expected to be a problem at any plant during the license renewal term.
Electromagnetic fields – acute effects (electric shock)	Site-specific	SMALL, MODERATE, OR LARGE. Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site. See § 51.53(c)(3)(ii)(H).
Electromagnetic fields – chronic effects	Uncategorized	UNCERTAIN. Biological and physical studies of 60-Hz electromagnetic fields have not found consistent evidence linking harmful effects with field exposures. However, research is continuing in this area and a consensus scientific view has not been reached.
Radiation exposures to public (license renewal term)	Generic	SMALL. Radiation doses to the public will continue at current levels associated with normal operations.
Occupational radiation exposures (license renewal term)	Generic	SMALL. Projected maximum occupational doses during the license renewal term are within the range of doses experienced during normal operations and normal maintenance outages, and would be well below regulatory limits.

Issue	Type of Issue	Finding
		Socioeconomic Impacts
Housing impacts	Site-specific	SMALL, MODERATE, OR LARGE. Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or in areas with growth control measures that limit housing development. See § 51.53(c)(3)(ii)(I).
Public services: public safety, social services, and tourism, and recreation	Generic	SMALL. Impacts to public safety, social services, and tourism and recreation are expected to be of small significance at all sites.
Public services: public utilities	Site-specific	SMALL OR MODERATE. An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability See § 51.53(c)(3)(ii)(I).
Public services: education (license renewal term)	Generic	SMALL. Only impacts of small significance are expected
Offsite land use (refurbishment)	Site-specific	SMALL OR MODERATE. Impacts may be of moderate significance at plants in low population areas. See § 51.53(c)(3)(ii)(I).
Offsite land use (license renewal term)	Site-specific	SMALL, MODERATE, OR LARGE. Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal. See § 51.53(c)(3)(ii)(I).
Public services: transportation	Site-specific	SMALL, MODERATE, OR LARGE. Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites. See § 51.53(c)(3)(ii)(J).

Issue	Type of Issue	Finding
Historic and archaeological resources	Site-specific	SMALL, MODERATE, OR LARGE. Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection. See § 51.53(c)(3)(ii)(K).
Aesthetic impacts (license renewal term)	Generic	SMALL. No significant impacts are expected during the license renewal term.
Aesthetic impacts of transmission lines (license renewal term)	Generic	SMALL. No significant impacts are expected during the license renewal term.
Postulated Accidents		
Design basis accidents	Generic	SMALL. The Staff has concluded that the environmental impacts of design basis accidents are of small significance for all plants.
Severe accidents	Site-specific	SMALL. The probability-weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives. See § 51.53(c)(3)(ii)(L).
Uranium Fuel Cycle and Waste Management		
Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high level waste)	Generic	SMALL. Off-site impacts of the uranium fuel cycle have been considered by the Commission in Table S-3 of this part. Based on information in the GEIS, impacts on individuals from radioactive gaseous and liquid releases including radon-222 and technetium-99 are small.

Issue	Type of Issue	Finding
Offsite radiological impacts (collective effects)	Generic	The 100 year environmental dose commitment to the U.S. population from the fuel cycle, high level waste and spent fuel disposal excepted, is calculated to be about 14,800 person rem, or 12 cancer fatalities, for each additional 20-year power reactor operating term. Much of this, especially the contribution of radon releases from mines and tailing piles, consists of tiny doses summed over large populations. This same dose calculation can theoretically be extended to include many tiny doses over additional thousands of years as well as doses outside the U. S. The result of such a calculation would be thousands of cancer fatalities from the fuel cycle, but this result assumes that even tiny doses have some statistical adverse health effect which will not ever be mitigated (for example, no cancer cure in the next thousand years), and that these doses projected over thousands of years are meaningful. However, these assumptions are questionable. In particular, science cannot rule out the possibility that there will be no cancer fatalities from these tiny doses. For perspective, the doses are very small fractions of regulatory limits, and even smaller fractions of natural background exposure to the same populations. Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR Part 54 should be eliminated. Accordingly, while the commission has not assigned a single level of significance for the collective effects of the fuel cycle, this issue is considered Category 1 [Generic].
Offsite radiological impacts (spent fuel and high level waste disposal)	Generic	For the high level waste and spent fuel disposal component of the fuel cycle, there are no current regulatory limits for offsite releases of radionuclides for the current candidate repository site. However, if we assume that limits are developed along the lines of the 1995 National Academy of Sciences (NAS) report, "Technical Bases for Yucca Mountain Standards," and that in accordance with the Commission's Waste Confidence Decision, 10 CFR 51.23, a repository can and likely will be developed at some site which will comply with such limits, peak doses to virtually all individuals will be 100 millirem per year or less. However, while the Commission has reasonable confidence that these

Issue	Type of Issue	Finding
		assumptions will prove correct, there is considerable uncertainty since the limits are yet to be developed, no repository application has been completed or reviewed, and uncertainty is inherent in the models used to evaluate possible pathways to the human environment. The NAS report indicated that 100 millirem per year should be considered as a starting point for limits for individual doses, but notes that some measure of consensus exists among national and international bodies that the limits should be a fraction of the 100 millirem per year. The lifetime individual risk from 100 millirem annual dose limit is about 3 x 10-3. Estimating cumulative doses to populations over thousands of years is more problematic. The likelihood and consequences of events that could seriously compromise the integrity of a deep geologic repository were evaluated by the Department of Energy in the "Final Environmental Impact Statement: Management of Commercially Generated Radioactive Waste," October 1980. The evaluation estimated the 70-year whole-body dose commitment to the maximum individual and to the regional population resulting from several modes of breaching a reference repository in the year of closure, after 1,000 years, after 100,000 years and after 100,000,000 years. Subsequently, the NRC and other federal agencies have expended considerable effort to develop models for the design and for the licensing of a high level waste repository, especially for the candidate repository at Yucca Mountain. More meaningful estimates of doses to populations may be possible in the future as more is understood about the performance of the proposed Yucca Mountain repository. Such estimates would involve very great uncertainty, especially with respect to cumulative population doses over thousands of years. The standard proposed by the NAS is a limit on maximum individual dose. The relationship of potential new regulatory requirements, based on the NAS report, and cumulative population impacts has not been determined, although the report articulates the view that protection of individuals will adequately protect the population for a repository at Yucca Mountain. However, EPA's generic repository standards in 40 CFR Part 191 generally provide an indication of the order of magnitude of cumulative risk to population that could result from the licensing of a Yucca Mountain repository, assuming the ultimate standards will be within the range of standards

Issue	Type of Issue	Finding
		now under consideration. The standards in 40 CFR Part 191 protect the population by imposing amount of radioactive material released over 10,000 years. The cumulative release limits are based on EPA's population impact goal of 1,000 premature cancer deaths worldwide for a 100,000 metric ton (MTHM) repository. Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR Part 54 should be eliminated. Accordingly, while the Commission has not assigned a single level of significance for the impacts of spent fuel and high level waste disposal, this issue is considered in Category 1 [Generic].
Nonradiological impacts of the uranium fuel cycle	Generic	SMALL. The nonradiological impacts of the uranium fuel cycle resulting from the renewal of an operating license for any plant are found to be small.
	Decommissioning	
Radiation doses	Generic	SMALL. Doses to the public will be well below applicable regulatory standards regardless of which decommissioning method is used. Occupational doses would increase no more than 1 man-rem caused by buildup of long-lived radionuclides during the license renewal term.
Waste management	Generic	SMALL. Decommissioning at the end of a 20-year license renewal period would generate no more solid wastes than at the end of the current license term. No increase in the quantities of Class C or greater than Class C wastes would be expected.
Air quality	Generic	SMALL. Air quality impacts of decommissioning are expected to be negligible either at the end of the current operating term or at the end of the license renewal term.
Water quality	Generic	SMALL. The potential for significant water quality impacts from erosion or spills is no greater whether decommissioning occurs after a 20-year license renewal period or after the original 40-year operation period, and measures are readily available to avoid such impacts.

Issue	Type of Issue	Finding
Ecological resources	Generic	SMALL. Decommissioning after either the initial operating period or after a 20-year license renewal period is not expected to have any direct ecological impacts.
Socioeconomic impacts	Generic	SMALL. Decommissioning would have some short-term socioeconomic impacts. The impacts would not be increased by delaying decommissioning until the end of a 20-year relicense period, but they might be decreased by population and economic growth.
	Environmental Justice	
Environmental Justice	Uncategorized	NONE. The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews.

Appendix C

Applicable Regulations, Laws, and Agreements

C. Applicable Regulations, Laws, and Agreements

The Atomic Energy Act of 1954 (AEA) authorizes States to establish programs to assume U.S. Nuclear Regulatory Commission (NRC) regulatory authority for certain activities. For example, through section 274b of the AEA, as amended, beginning on September 30, 2009, New Jersey assumes regulatory authority for: (1) byproduct materials as defined in 11e.(1) of the Act; (2) source materials; and (3) special nuclear materials in quantities not sufficient to form a critical mass; and (4) the disposal of low-level radioactive waste at a land disposal site as described in Title 10 of the Code of Federal Regulations (CFR) Part 6.

New Jersey is not seeking authority to: (a) conduct safety evaluations of sealed sources and devices manufactured in New Jersey and distributed in interstate commerce or (b) regulate 11e.(2) byproduct material resulting from the extraction or concentration of source material from ore processed primarily for its source material content, and its management and disposal. The New Jersey Bureau of Environmental Radiation is responsible for implementing State nuclear regulations.

In addition to implementing some Federal programs, State legislatures develop their own laws. State statutes supplement as well as implement Federal laws for protection of air, water quality, and ground water. State legislation may address solid waste management programs, locally rare or endangered species, and historic and cultural resources.

The Clean Water Act (CWA) allows for primary enforcement and administration through State agencies, provided the State program is at least as stringent as the Federal program. The State program must conform to the CWA and to the delegation of authority for the Federal National Pollutant Discharge and Elimination System (NPDES) program from the U.S. Environmental Protection Agency (EPA) to the State. The primary mechanism to control water pollution is the requirement for direct dischargers to obtain an NPDES permit, or in the case of states where the authority has been delegated from the EPA, an SPDES permit, pursuant to the CWA. In New Jersey, the New Jersey Department of Environmental Protection (NJDEP) issues and enforces NPDES permits.

One important difference between Federal regulations and certain State regulations is the definition of waters regulated by the State. Certain state regulations may include underground waters, while the CWA only regulates surface waters.

C.1 State Environmental Requirements

Certain environmental requirements, including some discussed earlier, may have been delegated to State authorities for implementation, enforcement, or oversight. Table C-1 provides a list of representative State environmental requirements that may affect license renewal applications for Salem Nuclear Generating Station (Salem) and Hope Creek Generating Station (HCGS).

Table C-1. State Environmental Requirements. *Salem and HCGS are subject to numerous State requirements regarding their environmental program. Those requirements are briefly described below. See Section 1.9 for Salem's and HCGS's compliance status with these requirements.*

Law/Regulation	Requirements
Air Quality Protection	
Air Pollution Control Act – N.J.S.A. 26:2C et seq. and N.J.A.C. 7:27-22 et seq. - Title V Operating Permit	This permit authorizes a facility to operate its emission units in accordance with all applicable federal and state regulations. The permit specifies the monitoring, record keeping, and reporting requirements to demonstrate compliance with these regulations and permit conditions. NJDEP has a joint preconstruction and Title V program.
Clean Air Interstate Rule (CAIR) Permit (Chapter 106, P.L. 1967 (N.J.S.A. 26:2C-9.2), 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.,* and Title V of the Clean Air Act)	CAIR sets annual state-wide emission budgets for sulfur dioxide (SO_2) and Nitrous Oxides (NO_x) for significant upwind contributors to particulate matter, 2.5 microns or less in diameter ($PM_{2.5}$) nonattainment, and it sets state-wide ozone season budgets (May 1st through September 30th) for contributors to 8-hour ozone nonattainment.
Water Resources Protection	
CWA (33 U.S.C. Section 401) - NJDEP	In accordance with Clean Water Act § 401, an applicant for a permit will obtain a water quality certificate or waiver from the appropriate state agency (NJDEP) prior to permit decision by the federal government.
Water Supply Management Act – N.J.S.A. 58A:1 et seq. and N.J.A.C. 7:20A et seq., Water Supply Laws – N.J.S.A. 58-9.1 et seq. and N.J.A.C. 7:10-10.1 et seq.	Water Allocation Permit - Required for diversion of more than 378,500 liters (100,000 gallons) of water per day (265 liters per minute; 70 gallons per minute [gpm]). Governs the granting of privileges to divert water, the management of water quality and quantity and the response to water supply shortages, drought and other water emergencies.
NJ Water Pollution Control Act of 1977 N.J.S.A. 58:10A-1 et seq. and N.J.A.C. 7:14A-1 et seq.	NJPDES – Discharge to Groundwater, NJPDES – Discharge to Surface Water (Industrial Stormwater Permit)
NJ Water Pollution Control Act of 1977 – N.J.S.A. 58:10A-1 et seq. and N.J.A.C. 7:14A-22 etseq and 7:14A-23 et seq.	Treatment Works Approval – required to build, install, modify, or operate any treatment works (any method or system for preventing, abating, reducing, storing, treating, separating, or disposing of pollutants including stormwater runoff or industrial waste in combined or separate stormwater and sanitary sewer systems).

Law/Regulation	Requirements
NJ Water Pollution Control Act of 1977 – N.J.S.A. 58:10A-1 to 13 – Federal Clean Water Act Amendments of 1977, 33 U.S.C. 1251 Section 401	Water Quality Certification – Ensures consistency with state water quality standards and management policies.
Water Quality Planning Act – N.J.S.A. 58:11A-1 et seq. and N.J.A.C. 7:15-1 et seq.	Prescribes water quality management policies and procedures concerning water quality management planning, including Statewide, areawide, and county water quality management plans and wastewater management plans.
Subsurface and Percolating Waters Act – N.J.S.A. 58:4 A-4.1 et seq.	Under this Act, the NJDEP reviews and issues a permit to drill a well.
NJ Safe Drinking Water Act –N.J.A.C. 7:10 and N.J.S.A. 58:12A-1 et seq	The NJDEP issues and enforces public water supply permits for operation of the plant site drinking water systems.
Coastal Area Facility Review Act (CAFRA) N.J.S.A. 13:19-1 et seq.	CAFRA regulates all development on beaches and dunes and other development within 46 meters (150 feet) of tidal waters, beach, or dune.
Flood Hazard Control Act N.J.S.A. 58:16A et seq. and N.J.A.C. 7:13 et seq.	Permitting standards and procedures for projects to be conducted in flood plains in order to minimize or avoid flood damage. Includes construction standards, standards for protection of near-stream vegetation, and methods of determining flood hazard area along waterways.
Water Pollution Control Act – N.J.S.A. 58:10-1 et seq.,	
Department of Environmental Protection Act – N.J.S.A. 13:1D et seq.	
Waterfront Development N.J.S.A. 12:5-3	Encompasses all development at or below the mean high water line in tidal waters of the state.
Delaware River Basin Commission Docket Approval – P.L. 87-328 (Federal) and N.J.S.A. 58:18-18 et seq.	Stations are within Delaware River Basin Commission (DRBC) regulatory area. The DRBC is responsible for the conservation and management of water resources within this area.
Soil Erosion and Sediment Control Act – P.L. 1975 C. 251, § 1	Projects that are regulated under Chapter 251 (which include projects that disturb greater than 464 square meters [5000 square feet] of land) must obtain a Soil Erosion and Sediment Control Plan Certification from the Soil Conservation District prior to the initiation of land disturbance activities.

Law/Regulation	Requirements
Release Prevention	
Spill Compensation and Control Act, P.L. 1990, c 78 and N.J.A.C. 7:1E et seq.	Discharge Prevention, Containment and Countermeasure and Discharge Cleanup and Removal
Toxic Catastrophe Prevention Act (TCPA), P.L. 1985, c403 and N.J.A.C. 7:31 et seq.	This act requires that certain facilities handling extraordinarily hazardous substances have approved risk management programs.
Superfund Amendments and Reauthorization Act (SARA) Title III (42 U.S.C. 11001 et seq.)	Emergency Planning Notification - State Emergency Response Commission and the local emergency planning committee.
NJ Spill Compensation and Control Act N.J.S.A 58:10-23.11	Emergency Release Notification
NJ Worker and Community Right-to-Know Act - N.J.S.A. 34:5-1 et seq. and NJ Pollution Prevention Act - N.J.S.A. 13:1D-35 et seq.	Toxic Chemical Release Inventory, Release and Pollution Prevention Report
Underground Storage of Hazardous Substances Act – N.J.S.A. 58:10A-21 et seq. and N.J.A.C. 7:14B	Registration of underground storage tanks (USTs), installation or substantial modification of USTs, UST Closure Plan Approval
Solid Waste Management Act – N.J.S.A. 13:1E-1 et seq. and N.J.A.C. 7:26G-1 et seq.	Regulates the registration, operation, maintenance and closure of sanitary landfills and other solid and hazardous waste facilities, as well as the registration, operation and maintenance of solid waste transporting operations and facilities in New Jersey.
Biotic Resource Protection	
NJ Natural Heritage Rare, Threatened, and Endangered Species Consultation	Consultation is requested from the New Jersey Natural Heritage Office regarding plant and animal species (and their habitat) that may be adversely affected by the project. Consultation with this agency identifies primarily state-listed species as well as federal species.
Freshwater Wetlands Protection Act – N.J.S.A. 13:9B and N.J.A.C. 7:7A, Wetlands Act of 1970 – N.J.S.A. 13:9A, N.J.S.A. 12:5-3, 13:1D-29 et seq., 13:9A-1 et seq., and 13:19-1 et seq.	Permit would be required for impacts to wetlands or any surrounding buffer area. Primary jurisdiction is NJDEP for freshwater wetlands.

Law/Regulation	Requirements
Coastal Permit Program Rules - N.J.A.C. 7:7, Coastal Zone Management Rules – N.J.A.C. 7:7E	Provides standards for coastal permit applications for coastal activities and developments under CAFRA, the Waterfront Development Law and Wetlands Act of 1970.
Division of Fish and Wildlife Rules – N.J.A.C. 7-25	Governs the management and harvest of fish and wildlife within the State.
Other	
National Historic Preservation Act of 1966, Section 106 – Stat. 915, 16 U.S.C. 470 et seq., 36 CFR Part 800	Designed to ensure that historic properties are given consideration during federal project planning and execution. These activities can include, but are not limited to: construction, rehabilitation and repair projects, demolition, licenses, and permits.
New Jersey Register of Historic Places Rules N.J.A.C. 7:4	Concerns the preservation of the State's historic, architectural, archaeological, engineering and cultural heritage.
NJDOT - Transport permit for radioactive waste N.J.A.C. 16:49	Governs the transportation of hazardous materials in the State of New Jersey; regulates the shipping, packaging, marking, labeling, placarding, handling, and transportation of hazardous materials; and, to the maximum extent practicable, conforms to the requirements of the regulations issued by the United States Department of Transportation
Radiation Protection Program – N.J.S.A. Title 26:2D and N.J.A.C. 7:28	Reduce exposure to unnecessary radiation through licensing users of radioactive materials, addressing radioactively contaminated sites, assessing exposure to non-ionizing radiation and conducting a statewide radon program.
Noise Control - N.J.A.C. 7:29	Sets forth regulations relating to the control and abatement of noise.

Note: The above list represents a composite of potential permits and approvals needed for an expansion/modification these facilities. The nature of the project, areas of disturbance, specific quantities of air emissions, water use and discharge, chemical usage, fuel stored, chemical usage and other information will allow for this list to be refined. Note that the NJDEP recommends that developers of new or significantly modified projects perform a "one stop" review such that NJDEP input as to permits and approvals can be obtained early in the project. In addition, permitting timeframes are from the submittal for a permit/approval to the issuance of the final notice to construct. Public participation, political intervention and legal challenges may alter the timeframe for individual permits/approvals.

C.2 Operating Permits and Other Requirements

Several operating permit applications may be prepared and submitted, and regulator approval and permits would be received prior to license renewal approval by the NRC. Table C-2 lists representative Federal, State, and local permits.

Table C-2. Federal, State, and Local Permits and Other Requirements. *Salem and HCGS are subject to other requirements regarding various aspects of their environmental program. Those requirements are briefly described below.*

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Federal			
Combined License / COL Application (Construction Permit and Operating License)	NRC	Standard Design Certifications and Combined Licenses for Nuclear Power Plants (10 CFR 52, specifically Subpart C, 52.71 – 52.103) and requirements contained in 10 CFR 50.30, with the environmental report prepared in accordance with Subpart A of 10 CFR 51. Administrative review per 10 CFR part 2 (see Note 1)	Construction and Operation
National Environmental Policy Act (NEPA) (Title 42 United States Code [USC] 4321-4347)	NRC	As referenced in 10 CFR 52 and within the context of the combined operating license application (COLA), Complete environmental report to assess impacts of both construction and operation, including alternative sites, as required by 10 CFR 51. Consultations triggered as a result of the NEPA action include National Historic Preservation Act Section 106, Section 7 of the Endangered Species Act, and Magnuson-Stevens Fishery Conservation Management Act	Construction
General Conformity Approval	NRC	Conformity to New Jersey Strategic Implementation Plan's purpose of eliminating or reducing severity and number of National Ambient Air Quality Standards (NAAQS) violations (NO_x and volatile organic compound (VOC) emissions); 40 CFR 93, Subpart B. Applies to construction activities and air emissions not regulated and/or New Source Review.	Construction

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Section 10 of the Rivers and Harbors Act of 1899 (33 USC 403) Water Obstruction and Encroachment Permit	US Army Corps of Engineers (Philadelphia District) / Jointly with the NJ DEP	Permit is required for structures or work in or affecting navigable waters of the US (including wetlands); 33 CFR 322	Construction. This permit activity is required for intake/discharge modifications and/or work at any waterfront piers.
Section 404 of Clean Water Act (33 USC 1344)	US Army Corps of Engineers (Philadelphia District) / Jointly with the NJDEP	Regulates the discharge of dredged or fill material into waters of the US. Projects affecting under 0.5 acres of wetlands or less than 152 meters (500 linear feet) of stream may be eligible for a general (nationwide, regional or state) permit; otherwise, an individual permit is required. Triggers Fish and Wildlife Service and National Marine Fisheries review.	Construction Requires a permit before dredged or fill material may be discharged into waters of the US, including wetlands. May apply to any underwater activity such as installation of an electric cable.
Section 401 of Clean Water Act – Certification and Wetlands (33 USC 1341)	US Army Corps of Engineers (Philadelphia District) / Jointly with the NJDEP	Required for all federal permits related to water quality. Any applicant for a Federal license or permit to conduct any activity including, but not limited to, the construction or operation of facilities, which may result in any discharge into the navigable waters, shall provide the licensing or permitting agency a certification from the State in which the discharge originates or will originate, or, if appropriate, from the interstate water pollution control agency having jurisdiction over the navigable waters at the point where the discharge originates or will originate, that any such discharge will comply with the applicable provisions of	Construction-related disturbance within a wetland area.
Spill Prevention and Countermeasure Control (SPCC) Plan	United States Environmental Protection Agency (EPA)	Needed for storage of oil products; Subparts A through C of Oil Pollution Prevention Regulation (40 CFR 112) are referred to as the SPCC rule. SPCC goal is to prevent oil spills from reaching the nation's waters; spill contingency plan is required as a part of the SPCC plan	Oil fuel may be needed for emergency power equipment.

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Superfund Amendments and Reauthorization Act of 1986 (SARA) Title 3 / Emergency Planning and Community Right to Know (EPRCRA) Sections 311-312 / Toxic Chemical Release Inventory (Section 313)	EPA	Chemicals may be subject to reporting requirements	Operation
Title III Air Toxics	EPA	Greater than 10 tons per year (tpy) of any single hazardous air pollutant or 25 tpy of any combination or a maximum available control technology (MACT) determination; 40 CFR 63	Construction/Operation
Risk Management Program	EPA	Section 112(r) of Clean Air Act – Chemicals subject to accident prevention regulations hazardous chemical storage; 40 CFR 68	Operation
316(a) and 316(b) of Clean Water Act	EPA	Intake and discharge structures. Section 316(a) of the Clean Water Act regulates heated discharges into waters of the United States; Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.	Modification or expansion of plant cooling system.
RCRA, Section 3010	EPA	Acknowledgement of Notification of Hazardous Waste Activity – Hazardous Waste Generation	Hazardous waste generation
Facility Response Plan, and Hazardous Waste Contingency Plan	EPA	Facility Response Plan Approval – Spill/Discharge Response Program. 40 CFR 9 and 112 and 40 CFR 265 Subparts C and D	Spill/Discharge Response Program
Spill Prevention Control, and Countermeasure (SPCC) rule	EPA	(40 CFR 112) Appendix F, Sections 1.2.1 and 1.2.2	Spill/Discharge Prevention Plan
Determination of No Hazard to Air Navigation	Federal Aviation Administration	Aeronautical study under provisions of 49 U.S.C., Section 44718. For new structures and possibly for construction equipment capable of affecting navigable airspace (e.g., cranes)	Generally, for construction of structures >61meters (>200 ft) above grade or shorter structures within glide path of an airport.

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Magnuson-Stevens Fishery Conservation Management Act (Public Law 94-265)	US Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service	Section 7 of the Endangered Species Act (16 USC 1531-1544) – Incidental Take Statement - Covers possession and disposition of impinged or stranded threatened or endangered species such as sea turtles and shortnose sturgeon. Consultation with these agencies is required for new construction/projects that may adversely affect federally listed species.	Construction, Operation
Consultation and Conference Activities Under Section 7 of the Endangered Species Act (ESA of 1973, as amended, 16 USC 1531 *et seq.*)	US Fish and Wildlife Service and National Marine Fisheries Service	The Endangered Species Act (ESA) requires consultation to insure that an action is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat. (*part of NEPA Process; NRC is lead*)	Construction
Floodplain Development Permit	Federal Emergency Management Agency (FEMA)	Verification from FEMA or FEMA-approved local authority for construction within a 100-year floodplain	Construction
Registration	US Department of Transportation	Required for hazardous material shipments; 40 CFR 5108	Operation
Alternate Fuels Capability Certification	US Department of Energy (DOE)	Baseload facilities fueled by natural gas or oil	Construction
Fuel Use Act of 1978	US Department of Energy (DOE)	Waiver	Construction
State of New Jersey			
Air Quality – Title V Operating Permit (significant modification) or State only Permit	NJDEP – Air Quality Permitting Program	This permit authorizes a facility to operate its emission units in accordance with all applicable federal and state regulations. The permit specifies the monitoring, record keeping, and reporting requirements to demonstrate compliance with these regulations and permit conditions. NJDEP has a joint preconstruction and Title V program.	Construction/Operation
Air Quality - Clean Air Interstate Rule (CAIR) Permit	NJDEP – Air Quality Permitting Program	Chapter 106, P.L. 1967 (N.J.S.A. 26:2C-9.2), 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.,* and Title V of the Clean Air Act and N.J.A.C. 7:27-30	Construction/Operation

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Air Quality - Nonattainment New Source Review	NJDEP – Air Quality Permitting Program	Imposes LAER control technology, emission offsets, and requirements on any proposed new project, if thresholds triggered	Salem County is non-attainment for ozone. NOx and VOC emissions are regulated as ozone precursors.
Air Quality - Prevention of Significant Deterioration (PSD) permit	NJDEP – Air Quality Permitting Program	Required if PSD thresholds are exceeded from any new unit or plant modification.	Construction
Water Quality – New Jersey Pollutant Discharge Elimination System (NJPDES) permit - Wastewater– Part 1 (Clean Water Act, 33 USC 1251 et seq. and N.J.A.C. 7:9A)	NJDEP – Division of Water Quality	Needed if treating and discharging wastewater or cooling water to surface waters (316 (b) Compliance) ; N.J.A.C 7:9A. Category B – Industrial Wastewater	Construction/Operation
Water Quality - NJPDES – Industrial Stormwater Permit	NJDEP – Division of Water Quality	General or individual permit for point source discharges disturbance areas. Requires erosion and sediment control plan. Category RF – Industrial Stormwater	Construction/Operation – Offsite stormwater discharge/conveyance.
Water Quality - NJPDES – Discharge to Groundwater Permit	NJDEP – Division of Water Quality	N.J.A.C. 7:14A and N.J.A.C. 7:9-6 et seq.	Construction/Operation
Water Quality - Water Quality Management Plan Consistency Determination	NJDEP – Division of Water Quality	NJDEP to determine if water quality measures are consistent with state and local Water Quality Management Plans	Construction/Operation
Water Supply - Water Allocation Permit (N.J.S.A. 58:1A-1 et seq.)	NJDEP – Division of Water Supply	Needed if diverting more than 378,500 liters (100,000 gallons) of water per day. (N.J.S.A. 58:1A-1 et seq.)	Current permit allows groundwater withdrawal of up to 163.5 million liters (43.2 million gallons)/month (30 days) and 1,136 million liters (300 million gallons)/year
Site Remediation – S1 Wastewater Treatment License/SRP-PI	NJDEP – Division of Water Quality and Division of Water Supply	N.J.A.C. 7:10A-1.14 System classification - Wastewater treatment	Operation
Water Supply – Safe Drinking Water	NJDEP – Division of Water Supply, Bureau of Safe Drinking Water	Ensure public water systems satisfy Federal and State drinking water requirements. N.J.A.C. 7:10	Operation
Toxic Catastrophic Prevention Act – T1 Water Treatment License/TCPA facilities	NJDEP – Bureau of Release Prevention	N.J.S.A. 13:1K-19 et seq. and the regulations arising from the Act as codified in N.J.A.C. 7:31.	

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
NJDEP - Treatment Works Approval	NJDEP – Division of Water Quality	Process involves assessing the design of new sewer lines and other wastewater conveyance facilities, as well as evaluating wastewater treatment plant design and ability to meet the effluent standards specified in the NJPDES permit for the facility.	Construction
Federal Coastal Zone Management Act (16 USC 1452 et seq.)	NJDEP – Division of Land Use Regulation	Verification of determination that renewal of operating license would be consistent with the NJ Coastal Zone Program.	Construction, Operation
NJDEP - Coastal Area Facility Review Act (CAFRA) Permit	NJDEP – Division of Land Use Regulation	CAFRA regulates all development on beaches and dunes, and development within 46 meters (150 feet) of tidal waters. N.J.S.A. 13:19-1 et seq. Permit	Construction, Operation
NJDEP - Waterfront Development Permit	NJDEP – Division of Land Use Regulation	Encompasses all development at or below the mean high water line in tidal waters of the state. It also stipulates that most developments up to 152 meters (500 feet) from the mean high water line in the Coastal Zone but outside of the CAFRA area, be subject to a permit. (N.J.S.A. 12:5-3)	Facility has both CAFRA and Waterfront Development permits.
NJDEP - Flood Hazard Area Permit	NJDEP – Division of Land Use Regulation	Sets forth requirements governing human disturbance to land and vegetation in the flood hazard area of a regulated water, and the riparian zone of a regulated water. Individual and General Permits, and Permits-by-Rule. (N.J.A.C. 7:13)	Construction, Operation, Maintenance
Wetlands – Freshwater Wetlands Permit	NJDEP – Division of Land Use Regulation	N.J.S.A. 13:19-1, 13:9B-1 and 13:1D-1	
Wetlands – Type "B" Wetlands Permit	NJDEP – Division of Land Use Regulation	N.J.A.C. 13:9A-4	
Storage Tank Registration and Permitting	NJDEP – Site Remediation Program	N.J.A.C. 7:14B	Operation
National Historic Preservation Act Section 106 Authorization to construct with historical / archeological resources	New Jersey State Historic Preservation (SHPO) Office	Requires federal agency issuing license to consider cultural impacts and consult with SHPO. SHPO must concur that license renewal will not affect any sites listed or eligible for listing. (*part of NEPA Process; NRC is lead*)	Construction

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Well Construction and Maintenance; Sealing of Abandoned Wells - Permits	NJDEP – Division of Water Supply	Requirements for the construction and decommissioning of wells. N.J.A.C. 7:9D et seq.	Operation of well
NJ Natural Heritage Program (Threatened and Endangered Species)	NJDEP – Natural Heritage Program (NHP)	NJ NHP conducts inventories and collects data regarding the State's native biological diversity. This information is stored in the State's Landscape Project.	Possible onsite survey for threatened and endangered species and habitat.
Riparian Grant/Riparian License	NJDEP – Bureau of Tidelands	The grant by the State Tidelands Resource Council of its right to area within the flow of the mean high tide or which was historically flowed by the mean high tide and was artificially filled in without the appropriate consent or permission of the State, as reflected upon the tidal claims map maintained by the N. J. Department of Environmental Protection, Division of Coastal Resources, Bureau of Tidelands.	Needed if additional transmission corridor is proposed.
Grant of Permanent Right-of-Way (N.J.S.A. 23:8A-1 and N.J.S.A. 13:8A-1 et seq.)		Grants permanent right-of-way for transmission line corridors associated with station	
NJDEP - Radiation – X-ray Facility Industrial	NJDEP – Division of Radiation Protection and Release Prevention	Required under the Radiation Protection Act N.J.A.C. 7:28 et seq., N.J.S.A. 26:2D	
NJDEP - Right-to-Know – Pollution Prevention Planning	NJDEP – Pollution Prevention and Community Right to Know	New Jersey Worker and Community Right to Know Act - N.J.S.A.34:5A	This information is used by the public, emergency planners, and first responders to determine the chemical hazards in the community.
NJDEP - Lab Certification – Non-Commercial Environmental Lab	NJDEP – Office of Quality Assurance	Ensures that regulatory decisions made by federal, state, and municipal government agencies are based upon accurate and dependable analytical data N.J.A.C. 7:18	Operation
NJDEP - Hazardous Waste Generator and Treatment, Storage, and Disposal	NJDEP – Compliance and Enforcement	N.J.A.C. 7.26G-6 et seq. – Regulates how hazardous waste is handled, stored and transported.	Construction and Operation

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Medical Waste Generator Certificate (N.J.A.C. 7:26-38.8)	NJDEP – Division of Solid and Hazardous Waste	Generation of regulated medical waste. Permit expires annually. N.J.A.C. 7:26-3A	Operation
Transport permit for radioactive waste	Department of Transportation	N.J.A.C. 16:49 - Governs the transportation of hazardous materials in the State of New Jersey, regulates the shipping, packaging, marking, labeling, placarding, handling, and transportation of hazardous materials, and, to the maximum extent practicable, conforms to the requirements of the regulations issued by the United States Department of Transportation	Operation
Local			
Delaware River Basin Commission Docket Approval	Delaware River Basin Commission	All public and private project proposed within the Basin that will substantially affect water resources must obtain commission approval. The commission has also established minimum restriction for flood plain development along non-tidal streams in the basin. State and local governments may impose more stringent requirements.	An Environmental Impact Statement (EIS) may be required for plant modification affecting water resources.
Delaware River Basin Commission – Surface Water Permit		Issued for the construction and operation of facilities.	Construction/Operation
Delaware River Basin Commission – Water Use Contract		Water use contract for Delaware River water withdrawal in compliance with D-73-193 CP.	Construction/Operation
Delaware River Basin Commission – Oxygen Demand Wasteload Allocation		Allocation for first stage oxygen demand discharge to Delaware Estuary.	Construction/Operation
Delaware River Basin Commission – Sewage Treatment Plant		Installation of new sewage treatment plant.	Construction
Erosion and Sediment Control Plan	Cumberland - Salem Conservation District	Per the requirements of P.L. 1975, Chapter 251, N.J.S.A. 4:29-39 (Erosion and Sediment Control), must be properly designed, implemented, and available on site for all earth disturbance activities that disturb 464 square meters (5,000 square feet) or more.	Onsite construction land clearing
Conditional Use Approval/Preliminary Site Plan Approval	Lower Alloways Creek Township	Lower Alloways Creek Township Code, Land Development Chapter, Section 5.07B2 -	Needed for any new development

License, Permit, or Other Required Approval	Responsible Agency	Authority	Relevance and Status
Preliminary and Final Site Plan Approval	Lower Alloways Creek Township	Lower Alloways Creek Township Code – Preliminary and Final Site Plan Approval	Needed for any new development
South Carolina Radioactive Waste Transport Permit	South Carolina Department of Health and Environmental Control – Division of Waste Management	South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429)	Transportation of radioactive waste into the State of South Carolina
Tennessee Radioactive Waste License-for-Delivery	State of Tennessee Department of Environment and Conservation Division of Radiological Health	Tennessee Department of Environment and Conservation Rule 1200-2-10.32	Transportation of radioactive waste into the State of Tennessee

Note: The above list represents a composite of potential permits and approvals needed for an expansion/modification of these facilities. The nature of the project, areas of disturbance, specific quantities of air emissions, water use and discharge, chemical usage, fuel stored, chemical usage and other information will allow for this list to be refined. Note that the NJDEP recommends that developers of new or significantly modified projects perform a “one stop” review such that NJDEP input as to permits and approvals can be obtained early in the project. In addition, permitting timeframes are from the submittal for a permit/approval to the issuance of the final notice to construct. Public participation, political intervention and legal challenges may alter the timeframe for individual permit/approvals.

Appendix D

Consultation Correspondences

D. CONSULTATION CORRESPONDENCES

The Endangered Species Act of 1973, as amended, the Magnuson-Stevens Fisheries Management Act of 1996, as amended; and the National Historic Preservation Act of 1966 as amended require that Federal agencies consult with applicable State and Federal agencies and groups prior to taking action that may affect threatened and endangered species, essential fish habitat, or historic and archaeological resources, respectively. This appendix contains consultation documentation.

Table D-1. Consultation Correspondences. *This is a list of the consultation documents sent between the NRC and other agencies in accordance with the National Environmental Policy Act (NEPA) requirements.*

Author	Recipient	Date of Letter
Delaware Dept. of Natural Resources & Environmental Control (S. Cooksey)	PSEG Nuclear LLC	July 14, 2009 ML101970074
New jersey Dept. of Environmental Protection, Hope Creek station (C. Dolphin)	PSEG Nuclear LLC	October 8, 2009 ML101970076
New Jersey Dept. of Environmental Protection, Salem Units 1 & 2 (C. Dolphin)	PSEG Nuclear LLC	October 8, 2009 ML101970075
U.S. Nuclear Regulatory Commission (B. Pham)	Pocomoke Indian Nation (J. Douglas) [(a)]	November 12, 2009 ML0930901248
U.S. Nuclear Regulatory Commission (B. Pham)	Delaware Division of Historical and Cultural Affairs (T. Slavin)	November 24, 2009 ML0931604446
U.S. Nuclear Regulatory Commission (B. Pham)	Maryland Historical Trust (J. R. Little)	November 24, 2009 ML0931604446
U.S. Nuclear Regulatory Commission (B. Pham)	New Jersey Historic Preservation Office (D. Saunders)	November 24, 2009 ML0931604446
U.S. Nuclear Regulatory Commission (B. Pham)	Pennsylvania Bureau for Historic Preservation (J. Cutler)	November 24, 2009 ML0931604446
U.S. Nuclear Regulatory Commission (B. Pham)	U.S. Fish and Wildlife Service (A. Scherer)	December 23, 2009 ML0933500195
U.S. Nuclear Regulatory Commission (B. Pham)	National Marine Fisheries (P. Kurkul)	December 23, 2009 ML093500057
State of Delaware Historical and Cultural Affairs (J. Larrivee)	U.S. Nuclear Regulator Comission (B.Pham)	January 4, 2010 ML101970071

National Marine Fisheries Service (M. Colligan)	U.S. Nuclear Regulatory Commission (B. Pham)	February 11, 2010 ML101970073
National Marine Fisheries Service (S. Gorski)	U.S. Nuclear Regulatory Commission (B. Pham)	February 23, 2010 ML101970072

[a]Similar letters went to sixteen other Native American Tribes listed in Section 1.8.

D.1 Consultation Correspondence

The following pages contain copies of the letters listed in Table D-1.

November 12, 2009

Pocomoke Indian Nation
P.O. Box 687
Mount Airy, MD 21771

SUBJECT: SALEM NUCLEAR GENERATING STATIONS, UNITS 1 AND 2, AND HOPE CREEK GENERATING STATION, UNIT 1, LICENSE RENEWAL APPLICATIONS

To Whom It May Concern:

The United States Nuclear Regulatory Commission (NRC) is seeking input for its environmental review of applications from PSEG Nuclear, LLC (PSEG Nuclear) for the renewal of the operating licenses for the Salem Nuclear Generating Station, Units 1 and 2 (SALEM), and Hope Creek Generating Station, Unit 1 (HCGS), located 18 miles south of Wilmington, Delaware. SALEM and HCGS are within a region that may be of interest to your tribe. As described below, the NRC process includes an opportunity for public and inter-governmental participation in the environmental review. We want to ensure that you are aware of our efforts and, pursuant to Title 10 of the *Code of Federal Regulations* Part 51.28(b) (10 CFR 51.28(b)), the NRC invites your tribe to provide input relating to the NRC's environmental review of these applications. In addition, as outlined in 36 CFR 800.8, the NRC plans to coordinate compliance with Section 106 of the National Historic Preservation Act of 1966 through the requirements of the National Environmental Policy Act of 1969.

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 up to an additional 20 years if NRC requirements are met. The current operating licenses for SALEM, Units 1 and 2, will expire on August 13, 2016 and April 18, 2020, respectively. The current operating license for HCGS, Unit 1, will expire on April 11, 2026. The license renewal applications for SALEM and HCGS, submitted by PSEG Nuclear, were dated August 18, 2009. Notices of acceptance for docketing of the applications for renewal of the facilities' operating licenses were published in the *Federal Register* on October 23, 2009 (SALEM: 74 FR 54854 and HCGS: 74 FR 54856).

The NRC is gathering information for SALEM and HCGS site-specific supplements to its Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants, NUREG-1437. The supplement will contain the results of the review of the environmental impacts on the area surrounding the SALEM and HCGS sites that are related to terrestrial ecology, aquatic ecology, hydrology, cultural resources, and socioeconomic issues (among others) and will contain a recommendation regarding the environmental acceptability of the license renewal action. Enclosed for your information, are the SALEM and HCGS site description, site boundary map, and transmission line map.

You are invited to submit comments on the supplemental environmental impact statements (SEIS). Comments are due by December 22, 2009. The draft SEIS is anticipated to be issued for public comment by the NRC on September 10, 2010. Your office will also receive a copy of the draft SEIS along with a request for comments.

The license renewal application is publicly available at the NRC Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, or from the NRC's Agencywide Documents Access and Management System (ADAMS). The ADAMS Public Electronic Reading Room is accessible at http://adamswebsearch.nrc.gov/dologin.htm. The accession numbers for the Environmental Reports (ERs) are ML092400532 for SALEM and ML092430484 for HCGS. Persons who do not have access to ADAMS, or who encounter problems in accessing the documents located in ADAMS, should contact the NRC's PDR reference staff by telephone at 1-800-397-4209, or 301-415-4737, or by e-mail at pdr.resource@nrc.gov.

The SALEM and HCGS ERs are also available on the Internet at:
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/salem.html
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/hope-creek.html. In addition, the Salem Free Library, located at 112 West Broadway Avenue, Salem, New Jersey 08079, has agreed to make the applications available for public inspection.

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If you have any questions or require additional information, please contact Charles Eccleston, Project Manager, by phone at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov, or Donnie Ashley at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA/

Bo M. Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
As stated

cc w/encls: See next page

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MModes, RI
DKern, RI
JBrand, RI
RConte, RI
RBellamy, RI
PBamford, RI
MMcLaughlin, RI

*Identical letters have been sent to: Ramapough Mountain Lenape, Nanticoke Lenni-Lenape Indians of New Jersey, Powhatan Renape Nation, Echota Chickamauga Cherokee Tribe of New Jersey, Osprey Band of Free Cherokees, Unalachtigo Band of the Nanticoke-Lenni Lenape Nation, Nanticoke Indians Association, Inc., Lenape Tribe of Delaware, Piscataway-Conoy Confederacy and Sub-Tribes, Inc., Piscataway Indian Nation, Youghiogheny Shawnee Band, Accohannock Indian Tribe, Nause-Waiwash Tribe, Delaware Nation, Pocomoke Indian Nation, Eastern Lenape Nation of Pennsylvania

ADAMS Accession No.: **ML093090124**

OFFICE	PM:RPB1:DLR	LA:RPOB:DLR	BC:RPB1:DLR
NAME	C. Eccleston	S. Figueroa	B. Pham
DATE	11/09/09	11/06/09	11/12/09

OFFICIAL RECORD COPY

Hope Creek Generating Station and
Salem Nuclear Generating Station,
Unit Nos. 1 and 2

cc:

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Dennis Winchester
Vice President - Nuclear Assessment
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Robert Braun
Site Vice President - Salem
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. George Barnes
Site Vice President - Hope Creek
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Carl Fricker
Vice President - Operations Support
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. George Gellrich
Plant Manager - Salem
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Larry Wagner
Site Vice President - Hope Creek
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. James Mallon
Manager - Licensing
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Jeffrie J. Keenan, Esquire
Manager - Licensing
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Michael Gaffney
Manager - Hope Creek Regulatory
Assurance
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Steven Mannon
Manager - Salem Regulatory Assurance
P.O. Box 236
Hancocks Bridge, NJ 08038

Township Clerk
Lower Alloways Creek Township
Municipal Building, P.O. Box 157
Hancocks Bridge, NJ 08038

Mr. Paul Bauldauf, P.E., Asst. Director
Radiation Protection Programs
NJ Department of Environmental
Protection and Energy, CN 415
Trenton, NJ 08625-0415

Mr. Brian Beam
Board of Public Utilities
2 Gateway Center, Tenth Floor
Newark, NJ 07102

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Hope Creek Generating Station and Salem Nuclear Generating Station, Unit Nos. 1 and 2 - 2 -

cc:

Senior Resident Inspector
Salem Nuclear Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

Mr. Michael Gallagher
Vice President – License Renewal Projects
Exelon Nuclear LLC
200 Exelon Way
Kennett Square, PA 19348

Mr. Ed Eilola
Plant Manager – Salem
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

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Plant Manager – Hope Creek
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Mr. Paul Davison
Director – Nuclear Oversight
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Hancocks Bridge, NJ 08038

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Director – Regulator Affairs
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PSEG Nuclear LLC
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Mr. William Mattingly
Manager – Salem Regulatory Assurance
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Earl R. Gage
Salem County Administrator
Administration Building
94 Market Street
Salem, NJ 08079

Senior Resident Inspector
Hope Creek Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND HOPE CREEK GENERATING STATION, UNIT 1, SITE DESCRIPTION

SITE DESCRIPTION

The Salem Nuclear Generating Station, Units 1 and 2 (SALEM), and Hope Creek Generating Station, Unit 1 (HCGS), sites are located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey. The sites are 15 miles south of the Delaware Memorial Bridge, 18 miles south of Wilmington, Delaware, and 7.5 miles southwest of Salem, New Jersey. The SALEM and HCGS sites each occupy approximately 220 acres and 153 acres within this area, respectively. The distances from the SALEM and HCGS reactor buildings to the site boundary are 4,200 feet and 2,960 feet, respectively. There are no major highways or railroads within approximately seven miles of the sites; the only land access is a road that PSEG Nuclear, LLC constructed to connect with an existing secondary road approximately three miles to the east. Barge traffic has access to the sites by way of the Intracoastal Waterway channel maintained in the Delaware River.

TOPOGRAPHY

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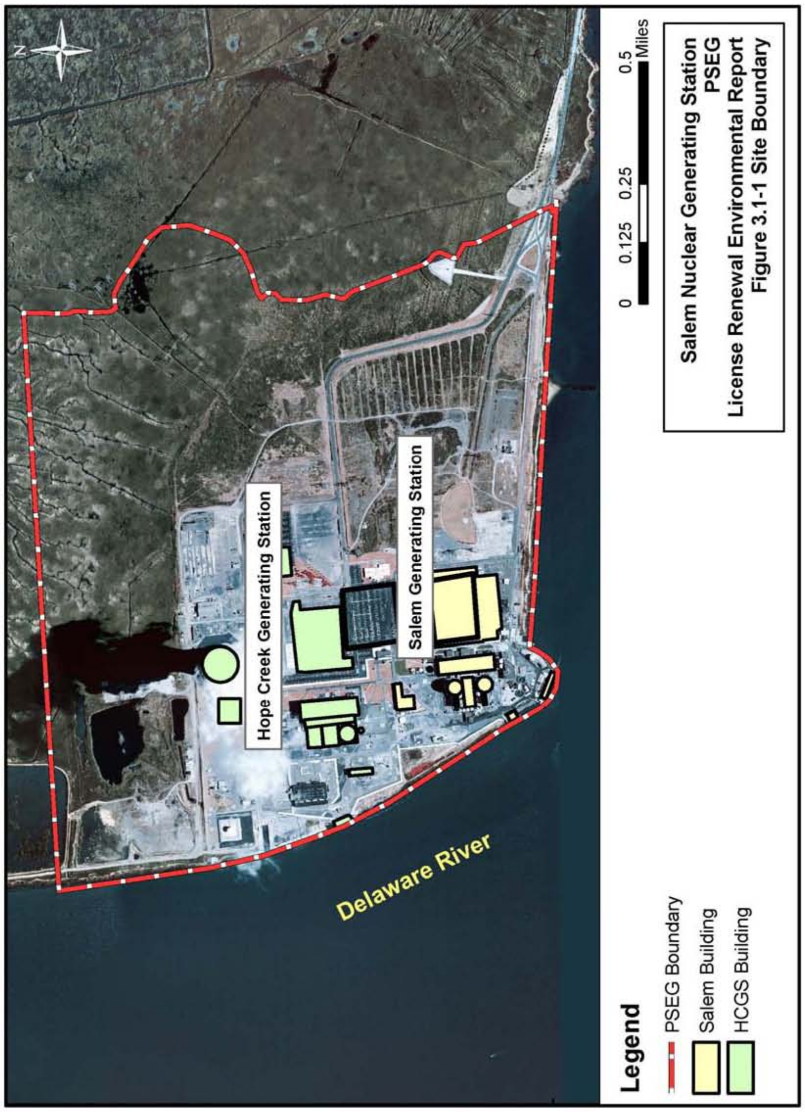
TRANSMISSION LINE CORRIDORS

Four 500-kV transmission lines extend beyond the site boundary to deliver electricity generated by SALEM and HCGS to the transmission system. One line extends north for 13 miles and then crosses over the New Jersey-Delaware state line. It then continues west over the Delaware River approximately four miles to the Red Lion substation. Two-thirds of the 17-mile corridor is 200 feet wide, and the remainder is 350 feet wide. Another segment of this line extends from the Red Lion substation eight miles northwest to the Keeney switch station. Two-thirds of the corridor is 200 feet wide and the remainder is 350 feet wide. Two lines share a 350 feet-wide corridor that extends approximately 40 miles north to the New Freedom switching station north of Williamstown, New Jersey. One of these lines is divided into two segments by the Orchard substation. The final 500-kV line extends northeast for 42 miles in a 350 feet-wide corridor to the New Freedom substation.

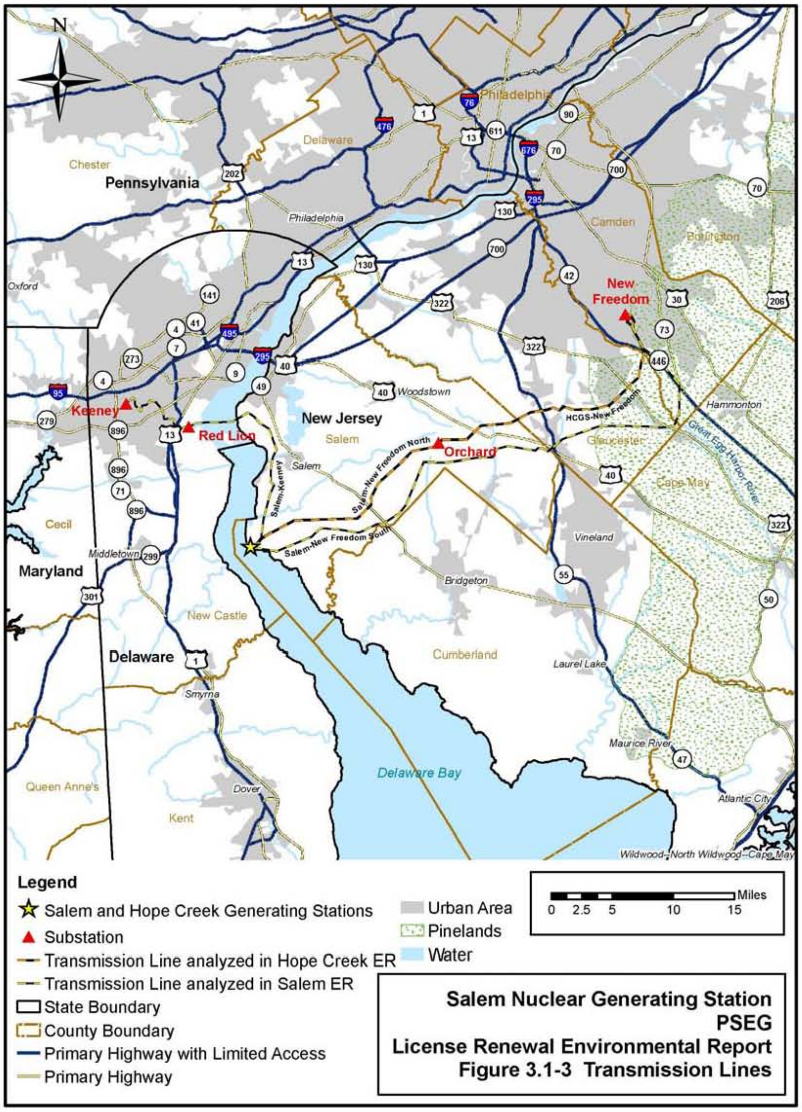
ENCLOSURE 1

SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND HOPE CREEK GENERATING STATION, UNIT 1, SITE BOUNDARY MAP



ENCLOSURE 2

**SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND
HOPE CREEK GENERATING STATION, UNIT 1, TRANSMISSION LINE MAP**



ENCLOSURE 3

November 24, 2009

Mr. Timothy A. Slavin, State Historic
Preservation Officer
Delaware Division of Historical and
Cultural Affairs
21 The Green
Dover, DE 19901

SUBJECT: SALEM AND HOPE CREEK LICENSE RENEWAL APPLICATIONS REVIEW

Dear Mr. Slavin:

The United States Nuclear Regulatory Commission (NRC) is seeking input for its environmental review of applications from PSEG Nuclear, LLC (PSEG Nuclear) for the renewal of the operating licenses for the Salem Nuclear Generating Station, Units 1 and 2 (SALEM), and Hope Creek Generating Station, Unit 1 (HCGS), located 18 miles south of Wilmington, Delaware. As described below, the NRC process includes an opportunity for public and inter-governmental participation in the environmental review. We want to ensure that you are aware of our efforts and, pursuant to Title 10 of the *Code of Federal Regulations* Part 51.28(a) (10 CFR 51.28(a)), the NRC invites you to provide input relating to the NRC's environmental review of these applications. In addition, as outlined in 36 CFR 800.8, the NRC plans to coordinate compliance with Section 106 of the National Historic Preservation Act of 1966 through the requirements of the National Environmental Policy Act of 1969.

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 up to an additional 20 years if NRC requirements are met. The current operating licenses for SALEM, Units 1 and 2, will expire on August 13, 2016 and April 18, 2020, respectively. The current operating license for HCGS, Unit 1, will expire on April 11, 2026. The license renewal applications for SALEM and HCGS, submitted by PSEG Nuclear, were dated August 18, 2009. Notices of acceptance for docketing of the applications for renewal of the facilities' operating licenses were published in the *Federal Register* on October 23, 2009 (SALEM: 74 FR 54854 and HCGS: 74 FR 54856).

The NRC is gathering information for SALEM and HCGS site-specific supplements to its Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants, NUREG-1437. The supplement will contain the results of the review of the environmental impacts on the area surrounding the SALEM and HCGS sites that are related to terrestrial

T. Slavin - 2 -

ecology, aquatic ecology, hydrology, cultural resources, and socioeconomic issues (among others) and will contain a recommendation regarding the environmental acceptability of the license renewal action. Enclosed for your information, are the SALEM and HCGS site description, site boundary map, 6-mile vicinity, and transmission line map.

You are invited to submit comments on the supplemental environmental impact statements (SEIS). Comments are due by December 22, 2009. The draft SEIS is anticipated to be issued for public comment by the NRC on September 10, 2010. Your office will also receive a copy of the draft SEIS along with a request for comments.

The license renewal application is publicly available at the NRC Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, or from the NRC's Agencywide Documents Access and Management System (ADAMS). The ADAMS Public Electronic Reading Room is accessible at http://adamswebsearch.nrc.gov/dologin.htm. The accession numbers for the Environmental Reports (ERs) are ML092400532 for SALEM and ML092430484 for HCGS. Persons who do not have access to ADAMS, or who encounter problems in accessing the documents located in ADAMS, should contact the NRC's PDR reference staff by telephone at 1-800-397-4209, or 301-415-4737, or by e-mail at pdr.resource@nrc.gov.

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- 3 -

If you have any questions or require additional information, please contact Charles Eccleston, Project Manager at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov, or Donnie Ashley, Project Manager at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA Donnie Ashley for/

Bo M. Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
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DAshley
JRobinson
REnnis
MModes, RI
JBrand, RI
RConte, RI
RBellamy, RI
PBamford, RI
MMcLaughlin, RI

*Identical letters have been sent to the following State Historic Preservation Offices: Delaware Historic Preservation Office; Maryland Historical Trust; New Jersey Historic Preservation Office; and Pennsylvania Bureau of Historic Preservation

ADAMS Accession No. **ML093160444**

OFFICE	PM:RPB1:DLR	LA:RPOB:DLR	BC:RPB1:DLR
NAME	C. Eccleston	S. Figueroa	B. Pham (D. Ashley for)
DATE	11/23/09	11/23/09	11/24/09

OFFICIAL RECORD COPY

Hope Creek Generating Station and
Salem Nuclear Generating Station,
Units1 and 2

cc:

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Dennis Winchester
Vice President - Nuclear Assessment
PSEG Nuclear
P.O. Box 236
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Mr. Robert Braun
Site Vice President - Salem
PSEG Nuclear LLC
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Township Clerk
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Radiation Protection Programs
NJ Department of Environmental
Protection and Energy, CN 415
Trenton, NJ 08625-0415

Mr. Brian Beam
Board of Public Utilities
2 Gateway Center, Tenth Floor
Newark, NJ 07102

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Hope Creek Generating Station and Salem Nuclear Generating Station, Units 1 and 2 - 2 -

cc:

Senior Resident Inspector
Salem Nuclear Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

Mr. Michael Gallagher
Vice President – License Renewal Projects
Exelon Nuclear LLC
200 Exelon Way
Kennett Square, PA 19348

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Hancocks Bridge, NJ 08038

Mr. Earl R. Gage
Salem County Administrator
Administration Building
94 Market Street
Salem, NJ 08079

Senior Resident Inspector
Hope Creek Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

SITE DESCRIPTION
SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND
HOPE CREEK GENERATING STATION, UNIT 1

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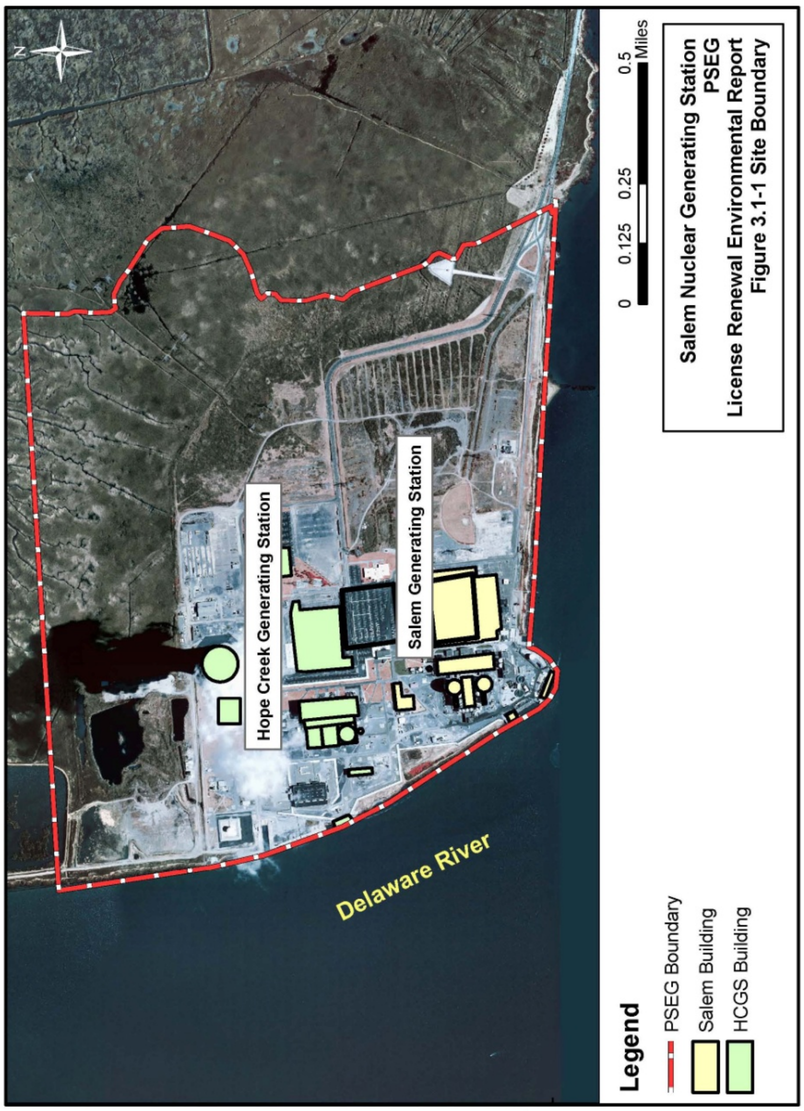
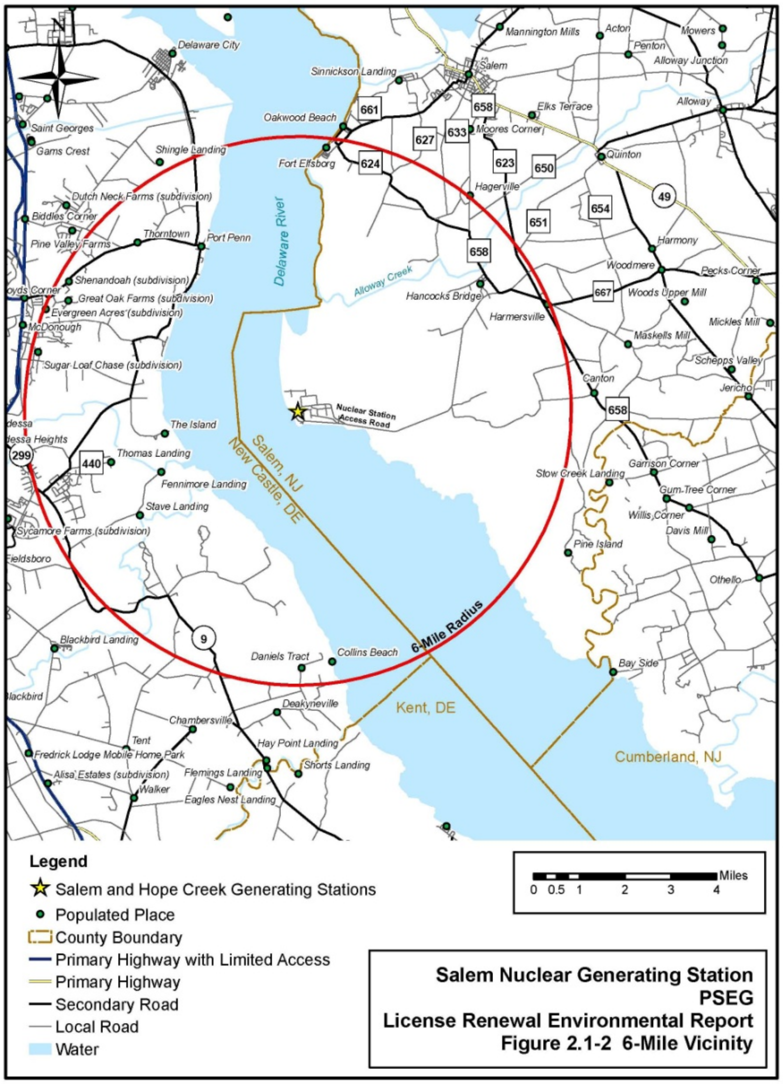
ENCLOSURE 1

SITE BOUNDARY MAP
SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND
HOPE CREEK GENERATING STATION, UNIT 1



ENCLOSURE 2

6-MILE VICINITY MAP
SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND
HOPE CREEK GENERATING STATION, UNIT 1



ENCLOSURE 3

TRANSMISSION LINE MAP
SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, AND
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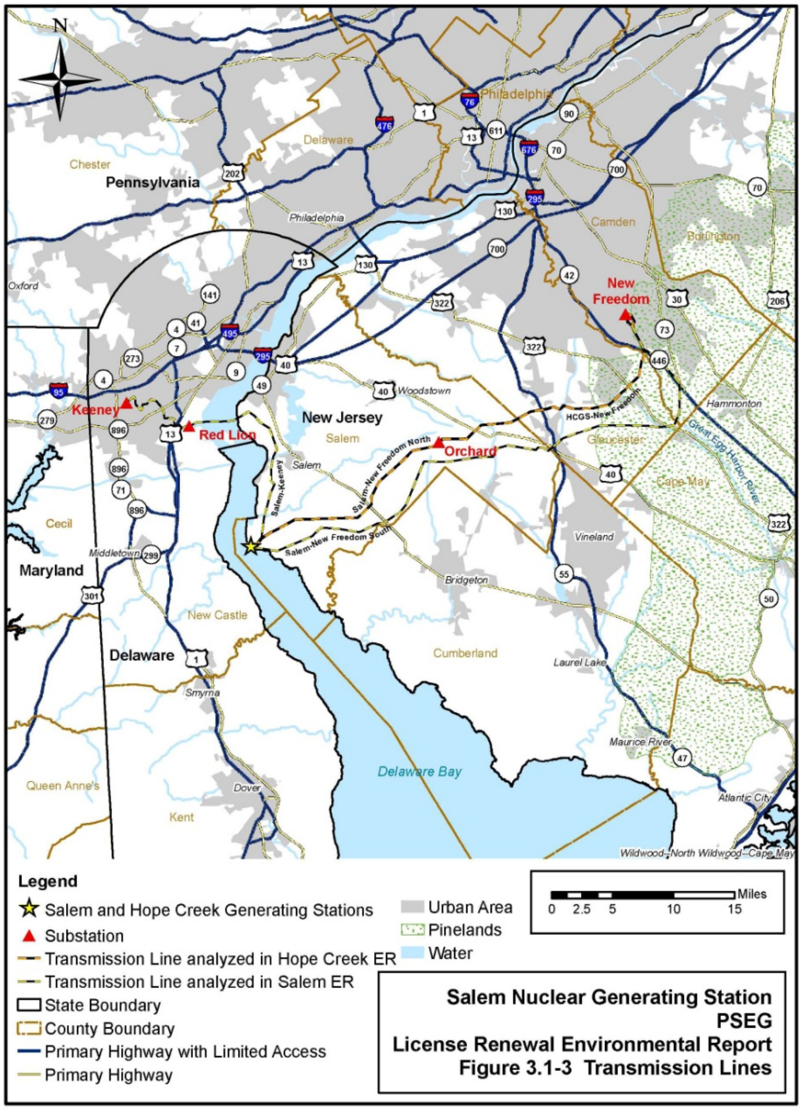

ENCLOSURE 4

November 24, 2009

Mr. J. Rodney Little, Director and State
Historic Preservation Officer
Maryland Historical Trust
100 Community Place, 3rd Floor
Crownsville, MD 21032-2023

SUBJECT: SALEM AND HOPE CREEK LICENSE RENEWAL APPLICATIONS REVIEW

Dear Mr. Little:

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http://www.nrc.gov/reactors/operating/licensing/renewal/applications/hope-creek.html. In addition, the Salem Free Library, located at 112 West Broadway Avenue, Salem, New Jersey 08079, has agreed to make the applications available for public inspection.

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J. Little - 3 -

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Sincerely,

/RA Donnie Ashley for/

Bo M. Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
As stated

cc w/encls: See next page

November 24, 2009

Mr. Daniel Saunders, Deputy State
Historic Preservation Officer
New Jersey Historic Preservation
Office
401 East State Street
P.O. Box 304
Trenton, NJ 08625-0404

SUBJECT: SALEM AND HOPE CREEK LICENSE RENEWAL APPLICATIONS REVIEW

Dear Mr. Saunders:

The United States Nuclear Regulatory Commission (NRC) is seeking input for its environmental review of applications from PSEG Nuclear, LLC (PSEG Nuclear) for the renewal of the operating licenses for the Salem Nuclear Generating Station, Units 1 and 2 (SALEM), and Hope Creek Generating Station, Unit 1 (HCGS), located 18 miles south of Wilmington, Delaware. As described below, the NRC process includes an opportunity for public and inter-governmental participation in the environmental review. We want to ensure that you are aware of our efforts and, pursuant to Title 10 of the *Code of Federal Regulations* Part 51.28(a) (10 CFR 51.28(a)), the NRC invites you to provide input relating to the NRC's environmental review of these applications. In addition, as outlined in 36 CFR 800.8, the NRC plans to coordinate compliance with Section 106 of the National Historic Preservation Act of 1966 through the requirements of the National Environmental Policy Act of 1969.

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 up to an additional 20 years if NRC requirements are met. The current operating licenses for SALEM, Units 1 and 2, will expire on August 13, 2016 and April 18, 2020, respectively. The current operating license for HCGS, Unit 1, will expire on April 11, 2026. The license renewal applications for SALEM and HCGS, submitted by PSEG Nuclear, were dated August 18, 2009. Notices of acceptance for docketing of the applications for renewal of the facilities' operating licenses were published in the *Federal Register* on October 23, 2009 (SALEM: 74 FR 54854 and HCGS: 74 FR 54856).

The NRC is gathering information for SALEM and HCGS site-specific supplements to its Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants, NUREG-1437. The supplement will contain the results of the review of the environmental impacts on the area surrounding the SALEM and HCGS sites that are related to terrestrial

D. Saunders - 2 -

ecology, aquatic ecology, hydrology, cultural resources, and socioeconomic issues (among others) and will contain a recommendation regarding the environmental acceptability of the license renewal action. Enclosed for your information, are the SALEM and HCGS site description, site boundary map, 6-mile vicinity, and transmission line map.

You are invited to submit comments on the supplemental environmental impact statements (SEIS). Comments are due by December 22, 2009. The draft SEIS is anticipated to be issued for public comment by the NRC on September 10, 2010. Your office will also receive a copy of the draft SEIS along with a request for comments.

The license renewal application is publicly available at the NRC Public Document Room (PDR), located at One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, or from the NRC's Agencywide Documents Access and Management System (ADAMS). The ADAMS Public Electronic Reading Room is accessible at http://adamswebsearch.nrc.gov/dologin.htm. The accession numbers for the Environmental Reports (ERs) are ML092400532 for SALEM and ML092430484 for HCGS. Persons who do not have access to ADAMS, or who encounter problems in accessing the documents located in ADAMS, should contact the NRC's PDR reference staff by telephone at 1-800-397-4209, or 301-415-4737, or by e-mail at pdr.resource@nrc.gov.

The SALEM and HCGS ERs are also available on the Internet at:
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/salem.html
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/hope-creek.html. In addition, the Salem Free Library, located at 112 West Broadway Avenue, Salem, New Jersey 08079, has agreed to make the applications available for public inspection.

The GEIS assesses the scope and impact of environmental effects that are associated with license renewal at any nuclear power plant site, and can also be found on the NRC's website or at the NRC's PDR.

Please submit any comments that you may have to the Chief, Rulemaking and Directives Branch, Division of Administrative Services, Office of Administration, Mailstop TWB 5B01M, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Comments may be submitted to the NRC by e-mail at SalemEIS@nrc.gov and HopeCreekEIS@nrc.gov by December 22, 2009. At the conclusion of the scoping process, the NRC staff will prepare a summary of the significant issues identified and the conclusions reached, and mail a copy to you.

D. Saunders - 3 -

If you have any questions or require additional information, please contact Charles Eccleston, Project Manager at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov, or Donnie Ashley, Project Manager at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA Donnie Ashley for/

Bo M. Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
As stated

cc w/encls: See next page

November 24, 2009

Ms. Jean Cutler, Deputy State
Historic Preservation Officer
Pennsylvania Bureau for Historic
Preservation
Commonwealth Keystone Building
2nd Floor
400 North Street
Harrisburg, PA 17120-0093

SUBJECT: SALEM AND HOPE CREEK LICENSE RENEWAL APPLICATIONS REVIEW

Dear Mr. Cutler:

The United States Nuclear Regulatory Commission (NRC) is seeking input for its environmental review of applications from PSEG Nuclear, LLC (PSEG Nuclear) for the renewal of the operating licenses for the Salem Nuclear Generating Station, Units 1 and 2 (SALEM), and Hope Creek Generating Station, Unit 1 (HCGS), located 18 miles south of Wilmington, Delaware. As described below, the NRC process includes an opportunity for public and inter-governmental participation in the environmental review. We want to ensure that you are aware of our efforts and, pursuant to Title 10 of the *Code of Federal Regulations* Part 51.28(a) (10 CFR 51.28(a)), the NRC invites you to provide input relating to the NRC's environmental review of these applications. In addition, as outlined in 36 CFR 800.8, the NRC plans to coordinate compliance with Section 106 of the National Historic Preservation Act of 1966 through the requirements of the National Environmental Policy Act of 1969.

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If you have any questions or require additional information, please contact Charles Eccleston, Project Manager at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov, or Donnie Ashley, Project Manager at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA Donnie Ashley for/

Bo M. Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
As stated

cc w/encls: See next page

December 23, 2009

Ms. Annette Scherer, Senior Fish &
Wildlife Biologist
U.S. Fish and Wildlife Service
New Jersey Field Office
927 North Main Street
Heritage Square, Building D
Pleasantville, NJ 08232

SUBJECT: REQUEST FOR LIST OF PROTECTED SPECIES WITHIN THE AREA UNDER EVALUATION FOR THE SALEM AND HOPE CREEK NUCLEAR GENERATING STATIONS LICENSE RENEWAL APPLICATION REVIEW

Dear Ms. Scherer:

The U.S. Nuclear Regulatory Commission (NRC) is reviewing an application submitted by PSEG Nuclear, LLC for the renewal of the operating licenses for Salem Nuclear Generating Station, Units 1 and 2 (Salem), and Hope Creek Nuclear Generating Station, Unit 1 (HCGS). Salem and HCGS are located in Salem County, New Jersey on the eastern bank of the Delaware River, approximately 7.5 miles (12 km) southwest of Salem, New Jersey. As part of the review of the license renewal application, the NRC is preparing a supplemental environmental impact statement (SEIS) under the provisions of the National Environmental Policy Act of 1969, as amended. The SEIS includes an analysis of pertinent environmental issues, including endangered or threatened species, and fish and wildlife impacts. This letter is being submitted under the provisions of the Endangered Species Act of 1973, as amended, and the Fish and Wildlife Coordination Act of 1934, as amended.

PSEG Nuclear, LLC has stated that it has no plans to alter current operations over the license renewal period. If granted renewed licenses, Salem and HCGS would use existing plant facilities and transmission lines and would not require additional construction or disturbance of new areas. Any maintenance activities would be limited to previously disturbed areas.

The Salem and HCGS sites each encompass approximately 220 and 153 acres, (89 and 62 ha) respectively, on the southern part of Artificial Island. Habitats on the island can best be described as tidal marsh and grassland. Aquatic communities of the Delaware River near Salem and HCGS are directly influenced by the quantity and quality of water in the river, which is the source of makeup water for HCGS's cooling tower and Salem's once-through cooling system. The enclosed map shows the layout of the sites in relation to the surrounding area.

HCGS employs a closed-cycle circulating water system for condenser cooling that consists of a natural draft cooling tower and associated withdrawal, circulation, and discharge facilities. HCGS withdraws brackish water with the service water system from the Delaware Estuary through an intake structure which was designed to control the amount of debris entering the

A. Scherer - 2 -

system. Service water provides cooling to various cooling systems and heat exchangers and is discharged to the cooling tower basin to serve as condenser cooling water makeup to replace the water lost through evaporation and cooling tower blowdown. The system effluent is then discharged into the Delaware Estuary through an underwater conduit.

The Salem units have once-through circulating water systems for condenser cooling that withdraw brackish water from the Delaware Estuary though one intake structure at the south end of the site. Through a separate intake structure, Salem also withdraws brackish water from the Delaware Estuary for use in its service water system. Both the cooling water system and service water system discharge to the river through a common return system.

Four 500-kV transmission lines extend beyond the site boundary to deliver electricity generated by Salem and HCGS to the transmission system. The following is a short description of each transmission line:

- Salem-New Freedom North – This 500 kV line, which is operated by PSE&G, runs northeast from HCGS for 63 km (39 mi) in a 107-m (350-ft) wide corridor to the New Freedom Switching Station north of Williamstown, New Jersey. This line shares the corridor with the 500 kV HCGS-New Freedom line.

- Salem-Red Lion segment of Salem-Keeney – This 500 kV line extends north from HCGS for 21 km (13 mi) and then crosses over the New Jersey-Delaware state line. It then continues west over the Delaware River about 6 km (4 mi) to the Red Lion substation. In New Jersey the line is operated by PSE&G and in Delaware it is operated by Pepco Holdings, Inc (PHI). Two thirds of the 27 km (17 mi) corridor is 61 m (200 ft) wide, and the remainder is 107 m (350 ft) wide.

- Red Lion-Keeney segment of Salem-Keeney – This 500 kV line, which is operated by PHI, extends from the Red Lion substation 13 km (eight mi) northwest to the Keeney switch station. Two thirds of the corridor is 70 m (200 ft) wide, and the remainder is 107 m (350 ft) wide.

- Salem-New Freedom South – This 500 kV line, operated by PSE&G, extends northeast from Salem for 68 km (42 mi) in a 107-m (350-ft) wide corridor from Salem to the New Freedom substation north of Williamstown, New Jersey.

- HCGS-New Freedom – This 500 kV line, operated by PSE&G, extends northeast from Salem for 69 km (43 mi) in a 107-m (350-ft) wide corridor to the New Freedom switching station north of Williamstown, New Jersey. This line shares the corridor with the 500 kV Salem-New Freedom North line. During 2008, a new substation (Orchard) was installed along this line, dividing it into two segments.

A. Scherer - 3 -

To support the SEIS preparation process and to ensure compliance with Section 7 of the Endangered Species Act, the NRC requests a list of species and information on protected, proposed, and candidate species and critical habitat that may be within the vicinity of Salem and Hope Creek and its associated transmission line right-of-way. In addition, please provide any additional information you consider appropriate under the provisions of the Fish and Wildlife Coordination Act. To support the project schedule, we request that this information be transmitted by February 15, 2010.

Your office will receive a copy of the draft SEIS along with a request for comments. The anticipated publication date for the draft SEIS is September 2010. If you would like to submit any comments regarding the scope of this SEIS, or have any questions, please contact Mr. Charles Eccleston, Project Manager at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov or Mr. Donnie Ashley, Project Manager at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA/

Bo Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

Enclosures:
1. Salem and Hope Creek Site Description
2. Salem and Hope Creek Site Boundary Map
3. Salem and Hope Creek 6 Mile Vicinity Map
4. Salem and Hope Creek Transmission System

cc w/encls: See next page

DISTRIBUTION: See next page

ADAMS Accession No. ML093350019

OFFICE	PM:DLR:RPB1	LA: DLR	PM:DLR:RPB1	BC:RPB1:DLR
NAME	C. Eccleston	S. Figueroa	D. Doyle	B. Pham
DATE	12/22/09	12/22/09	12/23/09	12/23/09

OFFICIAL RECORD COPY

Letter to Andrea Scherer from Bo Pham dated December 23, 2009

UBJECT: REQUEST FOR LIST OF PROTECTED SPECIES WITHIN THE AREA UNDER EVALUATION FOR THE SALEM AND HOPE CREEK NUCLEAR GENERATING STATIONS LICENSE RENEWAL APPLICATION REVIEW

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MModes, RI
JBrand, RI
RConte, RI
RBellamy, RI
PBamford, RI
MMcLaughlin, RI

Hope Creek and Salem Nuclear
Generating Station,
Units. 1 and 2

cc:

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Dennis Winchester
Vice President - Nuclear Assessment
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Robert Braun
Site Vice President - Salem
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. George Barnes
Site Vice President - Hope Creek
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Carl Fricker
Vice President - Operations Support
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. George Gellrich
Plant Manager - Salem
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Larry Wagner
Site Vice President - Hope Creek
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. James Mallon
Manager - Licensing
PSEG Nuclear
P.O. Box 236
Hancocks Bridge, NJ 08038

Mr. Jeffrie J. Keenan, Esquire
Manager - Licensing
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Michael Gaffney
Manager - Hope Creek Regulatory
Assurance
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Steven Mannon
Manager - Salem Regulatory Assurance
P.O. Box 236
Hancocks Bridge, NJ 08038

Township Clerk
Lower Alloways Creek Township
Municipal Building, P.O. Box 157
Hancocks Bridge, NJ 08038

Mr. Paul Bauldauf, P.E., Asst. Director
Radiation Protection Programs
NJ Department of Environmental
Protection and Energy, CN 415
Trenton, NJ 08625-0415

Mr. Brian Beam
Board of Public Utilities
2 Gateway Center, Tenth Floor
Newark, NJ 07102

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Senior Resident Inspector
Salem Nuclear Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

Hope Creek and Salem Nuclear Generating Station, Units. 1 and 2 - 2 -

cc:

Mr. Michael Gallagher
Vice President – License Renewal Projects
Exelon Nuclear LLC
200 Exelon Way
Kennett Square, PA 19348

Mr. Ed Eilola
Plant Manager – Salem
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Paul Davison
Director – Nuclear Oversight
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Ms. Christine Neely
Director – Regulator Affairs
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Ali Fakhar
Manager, License Renewal
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. William Mattingly
Manager – Salem Regulatory Assurance
PSEG Nuclear LLC
One Alloway Creek Neck Road
Hancocks Bridge, NJ 08038

Mr. Earl R. Gage
Salem County Administrator
Administration Building
94 Market Street
Salem, NJ 08079

Senior Resident Inspector
Hope Creek Generating Station
U.S. Nuclear Regulatory Commission
Drawer 0509
Hancocks Bridge, NJ 08038

Salem and Hope Creek Site Description

SITE DESCRIPTION

The Salem and Hope Creek sites are located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey. The sites are 15 miles (mi) south of the Delaware Memorial Bridge, 18 mi south of Wilmington, Delaware, and 7.5 mi southwest of Salem, New Jersey. The Salem and Hope Creek sites each occupy about 220 acres and 153 acres within this area, respectively. The distances from the Salem and Hope Creek reactor buildings to the site boundary are 4,200 feet (ft) and 2,960 ft, respectively. There are no major highways or railroads within about 7 mi of the site; the only land access is a road that PSEG constructed to connect with an existing secondary road about 3 mi to the east. Barge traffic has access to the site by way of the Intracoastal Waterway channel maintained in the Delaware River.

TOPOGRAPHY

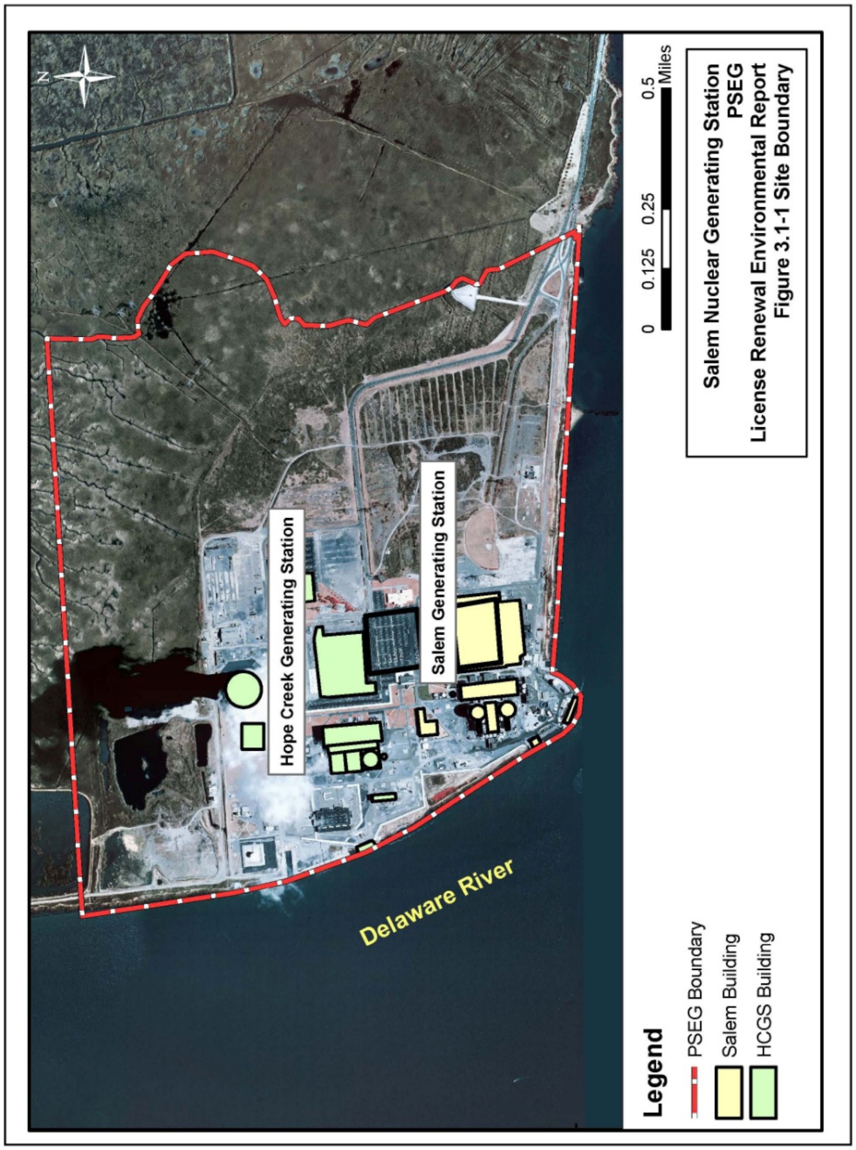
Artificial Island is a 1,500 acre island that was created, beginning early in the twentieth century, when the U.S. Army Corps of Engineers began disposing of hydraulic dredge spoils within a progressively enlarged diked area established around a natural bar that projected into the river. Habitats on the low and flat island, which has an average elevation of about 9 ft above mean sea level (msl) and a maximum elevation of about 18 ft above msl, can best be characterized as tidal marsh and grassland.

TRANSMISSION LINE CORRIDORS

Four 500-kV transmission lines extend beyond the site boundary to deliver electricity generated by Salem and Hope Creek to the transmission system. One line extends north for 13 mi and then crosses over the New Jersey-Delaware state line. It then continues west over the Delaware River about 4 mi to the Red Lion substation. Two thirds of the 17-mi corridor is 200 ft wide, and the remainder is 350 ft wide. Another segment of this line extends from the Red Lion substation 8 mi northwest to the Keeney switch station. Two thirds of the corridor is 200 ft wide, and the remainder is 350 ft wide. Two lines share a 350 ft wide corridor that extends about 40 mi north to the New Freedom switching station north of Williamstown, New Jersey. One of these lines is divided into two segments by the Orchard substation. The final 500-kV line extends northeast for 42 mi in a 350 ft wide corridor to the New Freedom substation.

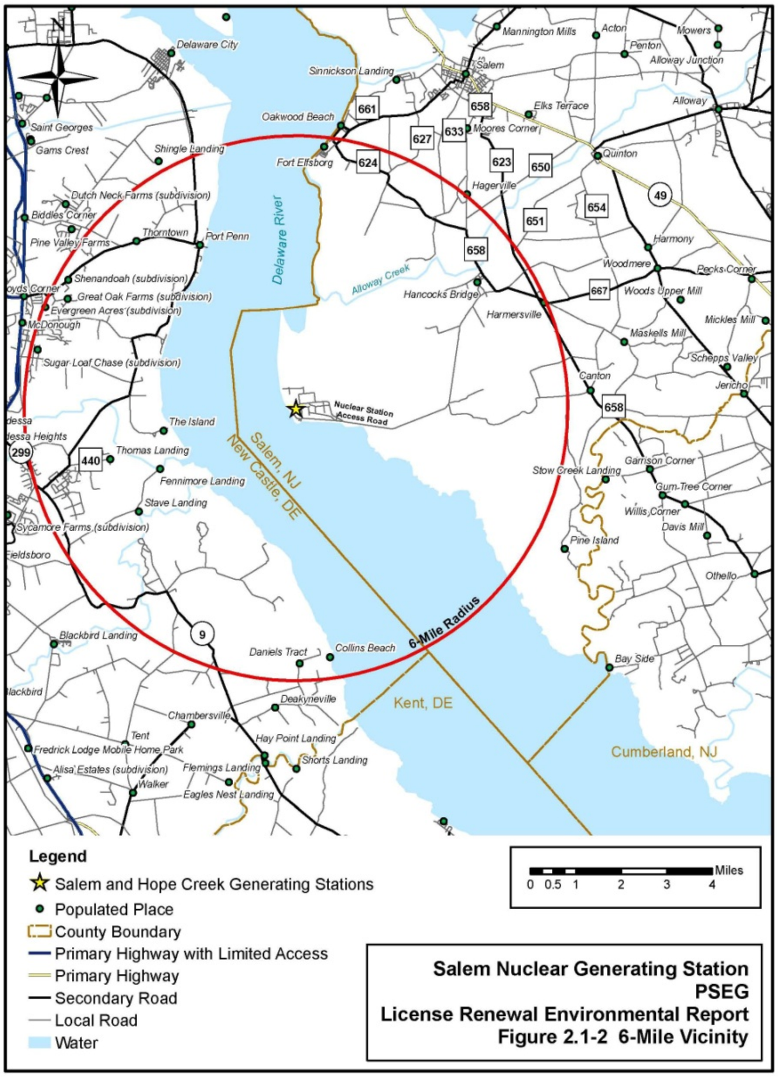
ENCLOSURE 1

Salem and Hope Creek Site Boundary Map



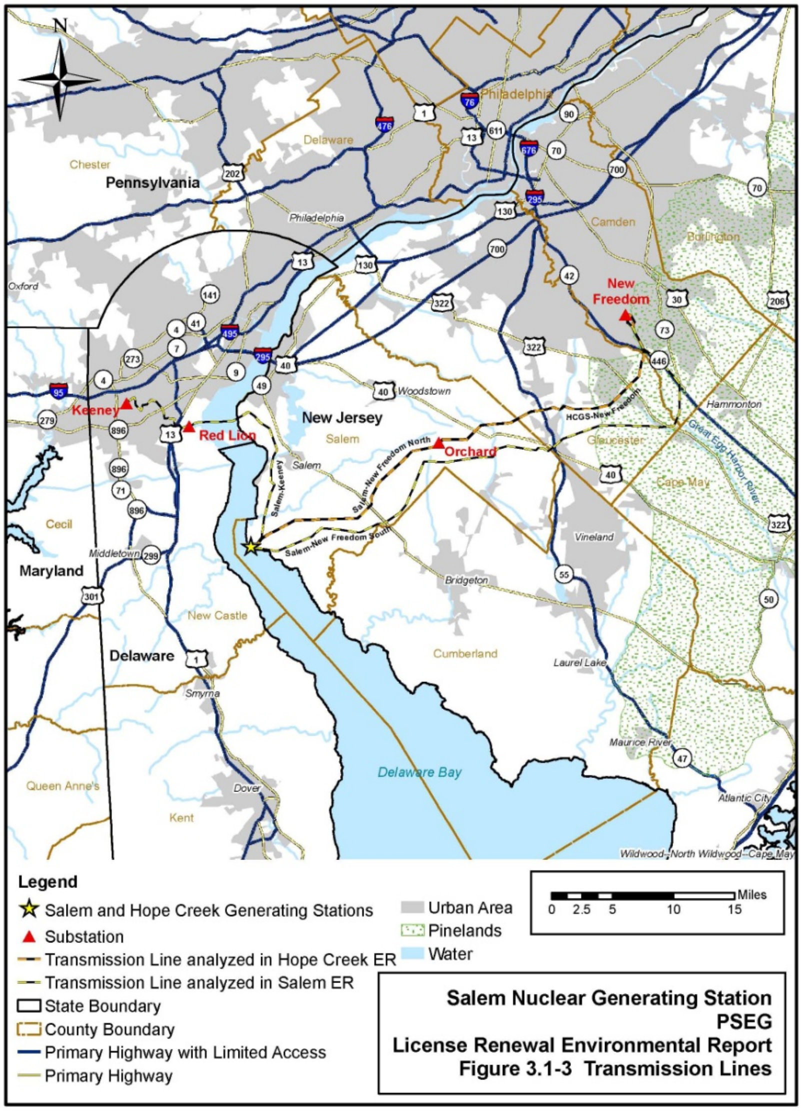
ENCLOSURE 2

Salem and Hope Creek 6 Mile Vicinity Map



ENCLOSURE 3

Salem and Hope Creek Transmission System



ENCLOSURE 4

December 23, 2009

Ms. Patricia Kurkul
Regional Administrator
National Marine Fisheries Service
Northeast Regional Office
55 Great Republic Drive
Gloucester, MA 01930-2276

SUBJECT: REQUEST FOR LIST OF PROTECTED SPECIES WITHIN THE AREA UNDER EVALUATION FOR THE SALEM AND HOPE CREEK NUCLEAR GENERATING STATIONS LICENSE RENEWAL APPLICATION REVIEW

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HCGS employs a closed-cycle circulating water system for condenser cooling that consists of a natural draft cooling tower and associated withdrawal, circulation, and discharge facilities. HCGS withdraws brackish water with the service water system from the Delaware Estuary through an intake structure which was designed to control the amount of debris entering the system. Service water provides cooling to various cooling systems and heat exchangers and is discharged to the cooling tower basin to serve as condenser cooling water makeup to replace the water lost through evaporation and cooling tower blowdown. The system effluent is then discharged into the Delaware Estuary through an underwater conduit.

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To support the SEIS preparation process and to ensure compliance with Section 7 of the Endangered Species Act, the NRC requests a list of endangered, threatened, candidate, and proposed species, and designated and proposed critical habitat under the jurisdiction of the National Marine Fisheries Service that may be in the vicinity of the Salem and HCGS sites and their transmission line corridors.

In addition, please provide any information you consider appropriate under the provisions of the Fish and Wildlife Coordination Act. Also, in support of the SEIS preparation and to ensure compliance with Section 305 of the Magnuson-Stevens Fishery Conservation and Management Act, the NRC requests a list of essential fish habitat that has been designated in the vicinity of the Salem and HCGS sites and their associated transmission line corridors. To support the project schedule, we request that this information be transmitted by February 15, 2010.

Your office will receive a copy of the draft SEIS along with a request for comments. The anticipated publication date for the draft SEIS is September 2010. If you would like to submit any comments regarding the scope of this SEIS, or have any questions, please contact Mr. Charles Eccleston, Project Manager at 301-415-8537 or by e-mail at Charles.Eccleston@nrc.gov or Mr. Donnie Ashley, Project Manager at 301-415-3191 or by e-mail at Donnie.Ashley@nrc.gov.

Sincerely,

/RA/

Bo Pham, Chief
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-272, 50-311, and 50-354

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OFFICE	PM:DLR:RPB1	LA:DLR	PM:DLR:RPB1	BC:RPB1:DLR
NAME	C. Eccleston	S. Figueroa	D. Doyle	B. Pham
DATE	12/22/09	12/22/09	12/23/09	12/23/09

OFFICIAL RECORD COPY

Letter to Patricia Kurkul from Bo Pham dated December 23, 2009

UBJECT: REQUEST FOR LIST OF PROTECTED SPECIES WITHIN THE AREA UNDER EVALUATION FOR THE SALEM AND HOPE CREEK NUCLEAR GENERATING STATIONS LICENSE RENEWAL APPLICATION REVIEW

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UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
55 Great Republic Drive
Gloucester, MA 01930-2276

FEB 11 2010

Bo Pham, Chief
Project Branch 1, Division of License Renewal
Office of Nuclear Reactor Regulation
US Nuclear Regulatory Commission
Washington, DC 20555-0001

Re: Salem and Hope Creek Nuclear Generating Stations License Renewal Review

Dear Mr. Pham,

This is in response to your letter dated December 23, 2009 regarding the Nuclear Regulatory Commission's ongoing review of an application submitted by PSEG Nuclear, LLC for the renewal of the operating licenses for Salem Nuclear Generaing Station, Units 1 and 2 and Hope Creek Nuclear Generaring Station, Unit 1. Salem and Hope Crek are located in Salem County, New Jserey on the eastern bacnk of the Delaware River. The NRC is currently preparing a supplemental environmental impact statement (SEIS) under the provisions of the National Environmental Policy Act of 1969, as amended. In your letter you requested information on the presence of species listed as threatened or endangered by NOAA's National Marine Fisheries Service (NMFS) that may occur in the vicinity of the Salem and Hope Creek generating stations.

NMFS Listed Species in the Action Area
Four species of sea turtles occur seasonally (May – November) in the Delaware River estuary, including the threatened loggerhead (*Caretta caretta*), and endangered Kemp's ridley (*Lepidochelys kempi*), green *(Chelonia mydas*), and leatherback (*Dermochelys coriacea*) sea turtles. Additionally, a population of endangered shortnose sturgeon (*Acipenser brevirostrum*) occurs in the Delaware River. Shortnose sturgeon, loggerhead, Kemp's ridley and green sea turtles have all been documented in the Delaware River near or at the project site. Leatherback sea turtles are less likely to occur near the facility. At this time there is no critical habitat as designated by NMFS in the vicinity of either facility.

Any discretionary federal action that may affect a listed species must undergo consultation pursuant to Section 7 of the Endangered Species Act (ESA) of 1973, as amended. Consultation pursuant to Section 7 of the ESA between NRC and NMFS on the effects of the operation of the existing Salem and Hope Creek facilities has been ongoing since 1979. Most recently, a Biological Opinions (Opinion) was issued by NMFS on May 14, 1993 in which NMFS concluded that the ongoing operation was not likely to jeopardize shortnose sturgeon, Kemp's ridley, green or loggerhead sea turtles. This Opinion was amended by a letter dated January 21, 1999 which made certain modifications to the Incidental Take Statement.

The relicensing of the Salem and Hope Creek Generating Stations by the NRC would be a federal action that will require section 7 consultation. If it is determined through consultation between the NRC and NMFS that the action is likely to adversely affect any listed species (i.e., if any adverse effect to listed species may occur as a direct or indirect result of the proposed action or its interrelated or interdependent actions, and the effects are not: discountable, insignificant, or beneficial) then a formal consultation, resulting in the issuance of a Biological Opinion and accompanying Incidental Take Statement would be required.

Any NEPA documentation prepared by NRC relating to the relicensing of these facilities should contain an assessment of the facility's impact on listed shortnose sturgeon and sea turtles. As shortnose sturgeon and sea turtles have been impinged at the intakes of the existing Salem facility, in the draft SEIS the NRC should consider the potential for future impingement of these species. Additional effects that should be considered by NRC include impingement or entrainment of prey resources, discharge of pollutants, including heated effluent, and effects of the maintenance of shoreline facilities, including dredging.

Technical Assistance for Candidate Species

Candidate species are those petitioned species that are actively being considered for listing as endangered or threatened under the ESA, as well as those species for which NMFS has initiated an ESA status review that it has announced in the *Federal Register*.

Atlantic sturgeon (*Acipenser oxyrinchus oxyrinchus*) occur in the Delaware River. In 2006, NMFS initiated a status review for Atlantic sturgeon to determine if listing as threatened or endangered under the ESA is warranted. The Status Review Report was published on February 23, 2007. NMFS is currently considering the information presented in the Status Review Report to determine if any listing action pursuant to the ESA is warranted at this time. If it is determined that listing is warranted, a final rule listing the species could be published within a year from the date of publication of the listing determination or proposed rule. Currently, NMFS expects to publish a finding as to whether any listing action is appropriate by the Fall of 2010. As a candidate species, Atlantic sturgeon receive no substantive or procedural protection under the ESA; however, NMFS recommends that project proponents consider implementing conservation actions to limit the potential for adverse effects on Atlantic sturgeon from any proposed project. Please note that once a species is proposed for listing the conference provisions of the ESA apply (see 50 CFR 402.10). As the listing status for this species may change, NMFS recommends that NRC obtain updated status information from NMFS prior to the publication of the draft SEIS.

My staff looks forward to working with PSEG and NRC as you move forward with the relicensing process. Should you have any questions regarding this correspondence or would like to arrange a meeting to discuss the effects of the proposed action on listed and candidate species, please contact Julie Crocker of my staff at (978)282-8480 or by e-mail (Julie.Crocker@noaa.gov). Questions specific to the status of Atlantic sturgeon should be directed to Lynn Lankshear of my staff at (978)282-8473 or by e-mail (Lynn.Lankshear@noaa.gov). It is my understanding that correspondence from NMFS' Habitat Conservation Division regarding Essential Fish Habitat as designated under the Magnuson-Steven Fisheries Management and Conservation Act as well information related to the Fish and Wildlife Conservation Act will be provided to NRC under separate cover.

Sincerely,

Mary Colligan

Mary A. Colligan
Assistant Regional Administrator for
Protected Resources

CC: Greene, F/NER4 SH

EC: Crocker, F/NER3

File Code: Sec 7 NRC Salem and Hope Creek Nuclear (Relicensing)
PCTS: T/NER/2010/00335

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE

Habitat Conservation Division
James J. Howard Marine
Sciences Laboratory
74 Magruder Road
Highlands, NJ 07732

February 23, 2010

Bo Pham, Chief
Project Branch 1, division of License Renewal
Office of Nuclear Reactor Regulation
US Nuclear Regulatory Commission
Washington, DC 20555-0001

RE: Salem and Hope Creek Nuclear Generating Station License Renewal Review
Salem County, New Jersey

Dear Mr. Pham:

The National Marine Fisheries Service (NMFS) Northeast Region Habitat Conservation Division is in receipt of your letter dated December 23, 2009 regarding the Nuclear Regulatory Commission's (NRC) ongoing review of an application submitted by PSE&G Nuclear, LLC for the renewal of the operating licenses for Salem Nuclear Generating Station, Units 1 and 2 (Salem) and Hope Creek Nuclear Generating Station, Unit 1 (HCNGS). Salem and HCNGS are both located along the Delaware River in an area of Salem County, New Jersey known as Artificial Island. According to your letter, the NRC is currently preparing a supplemental environmental impact statement (SEIS) under the provisions of the National Environmental Policy Act of 1969, as amended. In your letter, you have requested a list of essential fish habitat designated in accordance with Section 305 of the Magnuson Stevens Act (MSA) in the vicinity of the Salem and HCNGS sites as well as any appropriate information under the provisions of the Fish and Wildlife Coordination Act of 1934, as amended.

Magnuson Stevens Fishery Conservation and Management Act (MSA)
Section 305 (b)(2) of the 1996 amendments to the Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires all federal agencies to consult with NOAA Fisheries on any action authorized, funded, or undertaken by that agency that may adversely affect EFH. Included in this consultation process is the preparation of a complete and appropriate EFH assessment to provide necessary information on which to consult. Our EFH regulation at 50 CFR 600.905 mandates the preparation of EFH assessments and generally outlines each agency's obligations in this consultation procedure.

The estuarine portions of the Delaware River and its tributaries including the estuarine areas crossed by the transmission lines have been designated as essential fish habitat (EFH) for a wide variety of species including red hake (*Urophycis chuss*), winter flounder (*Pseudopleuronectes americanus*), windowpane flounder (*Scophthalmus aquosus*), bluefish (*Pomatomus saltatrix*), Atlantic butterfish (*Peprilus triacanthus*), scup (*Stenotomus chrysops*), summer flounder (*Paralichthys dentatus*), scup (*Stenotomus chrysops*), black sea bass (*Centropristis striata*), king mackerel (*Scomberomorus cavalla*), Spanish mackerel (*Scomberomorus maculatus*), cobia

(*Rachycentron canadum*), little skate (*Leucoraja erinacea*), winter skate (*Leucoraja ocellata*) and clearnose skate (*Raja eglanteria*). A more detailed listing of EFH and federally managed species and EFH consultation requirements can be found on our website at: www.nero.nmfs.gov/hcd.

The EFH final rule published in the Federal Register on January 17, 2002 defines an adverse effect as: "any impact which reduces the quality and/or quantity of EFH." The rule further states that:

> An adverse effect may include direct or indirect physical, chemical, or biological alterations of the waters or substrate and loss of, or injury to, benthic organisms, prey species and their habitat and other ecosystems components, if such modifications reduce the quality and/or quantity of EFH. Adverse effects to EFH may result from action occurring within EFH or outside EFH and may include site-specific or habitat-wide impacts, including individual, cumulative, or synergistic consequences of actions.

In order to complete the required EFH consultation, NRC must submit a full and compete EFH assessment that considers the individual and cumulative and the direct and indirect impacts of the proposed relicensing on EFH, federal managed species and their prey recognizing the definition of adverse impact discussed above. The required contents of an EFH assessment includes: 1) a description of the action; 2) an analysis of the potential adverse effects of the action on EFH and the managed species; 3) the ACOE's conclusions regarding the effects of the action on EFH; 4) proposed mitigation, if applicable. Other information that should be contained in the EFH assessment includes: 1) the results of on-site inspections to evaluate the habitat and site-specific effects; 2) the views of recognized experts on the habitat or the species that may be affected; 3) a review of pertinent literature and related information; and 5) an analysis of alternatives to the action that could avoid or minimize the adverse effects on EFH. Please note that any impacts to prey species of federally managed fish species such as juvenile *Alosids*, bay anchovy (*Anchoa mitchilli*), Atlantic silverside (*Menidia menidia*), striped killifish (*Fundulus majalis*), mummichog *(Fundulus heteroclitus*) and weakfish (*Cynoscion regalis*) would be considered an impact to EFH.

Fish and Wildlife Coordination Act

The Delaware Estuary including its tributaries provides habitat for a wide variety of NOAA trust resources including alewife (*Alosa pseudoharengus*), American eel (*Anguilla rostrata*) American shad (*Alosa sapidissima*), Atlantic croaker (*Micropogonias undulatus*), Atlantic menhaden (*Brevoortia tyrannus*), Atlantic sturgeon (*Acipenser oxyrinchus oxyrinchus*), blueback herring (*Alosa aestivalis*), bluefish, hickory shad (*Alosa mediocris*), spot (*Leiostomus xanthurus*) tautog (*Tautoga onitis*), weakfish, white perch (*Morone americana*), yellow perch (*Perca flavescens*), striped bass (*Morone saxatilis*), hogchoker (*Trinectes maculatus*), killifish, bay anchovy, silversides, mummichog and may others.

The Delaware River and its tributaries including some of those crossed by the transmission lines, are migratory pathways as well as spawning, nursery and forage habitats for anadromous fishes such as American shad, alewife, blueback herring, white perch and striped bass. Because landing statistics and the number of fish observed on annual spawning runs indicate a drastic decline in alewife and blueback herring populations throughout much of their range since the mid-1960's, they have been designated as species of concern by NMFS in a Federal Register Notice dated October 17, 2006 (71 FRN 61022). "Species of concern" are those species about which NMFS has some concerns regarding status and threats, but for which insufficient information is available to indicate a need to list the species under the Endangered Species Act. NMFS would not support any actions that would disrupt or prevent the upstream migration of anadromous fish, or would reduce or degrade their spawning, nursery or forage habitat.

Atlantic sturgeon (*Acipenser oxyrinchus oxyrinchus*) are also present in the Delaware River. Atlantic sturgeon were listed as a candidate species for listing under the Endangered Species Act (ESA) by NMFS in the Federal Register on published on October 16, 2006 (71 FRN 61002). The term "candidate species" refers to species that are the subject of a petition to list as threatened or endangered and for which NMFS has determined that listing pursuant to section 4 (b) (3) (A) of the ESA may be warranted, and those species are not the subject of a petition but for which NMFS has announced the initiation of a status review in the Federal Register.

The Atlantic Sturgeon Status Review Team (ASSRT) has determined that the Hudson River and Delaware River Atlantic sturgeon stock constitute a distinct population segment (DPS) called the New York Bight DPS. The ASSRT has also concluded that the New York Bight DPS was likely (>50 % chance) to become endangered within the next twenty years. NMFS is currently considering the information in the status report to determine if action under the ESA is warranted. As stated in the February 11, 2010 letter from our Protected Resources Division in Gloucester, MA, Atlantic sturgeon receive no substantive or procedural protection under the Endangered Species Act. However, until a listing decision is made, they remain a NOAA Trust resource under our Fish and Wildlife Coordination Act authorities.

Submerged aquatic vegetation (SAV) including wild celery (*Vallisneria americana*) can be found in some areas of the Delaware River and its tributaries. SAV provides valuable nursery, forage and refuge habitat for a variety of fish including striped bass, American shad, alewife, and blueback herring. It is also an important food source for waterfowl. As water quality in the Delaware River continues to improve, more areas of SAV may be found within the River. To date, there has been no comprehensive mapping of SAV in the Delaware Estuary.

In recent years, efforts have been made to restore oyster beds in Delaware Bay. Since 2004, the Army Corps of Engineers has worked with the States of New Jersey and Delaware to plant shell in portions of natural oyster beds in Delaware Bay. Native oysters are ecologically important species. According to the New Jersey Department of Environmental Protection, an expansive area of habitat has been identified near the Salem and HCNGS.

Blue crab (*Callinectes sapidus*) can also be found in the vicinity of the Salem and HCNGS. The crabs can generally be found in the lower salinity areas of the estuary in the summer and higher salinities in the winter. Following mating in the summer, which typically occurs in lower salinity waters, the females move to high salinity waters to spawn. After spawning, the larvae move toward the lower salinity areas to mature.

Lastly, horseshoe crabs remain a species of concern in the Delaware Estuary. In recent years NMFS has banned fishing for horseshoe crabs in federal waters off the mouth of Delaware Bay. The States of New Jersey and Delaware have also taken steps to restrict the harvest of horseshoe crabs in State waters. The ban provides additional protection for local horseshoe crab stocks and ensures that declining populations of migratory shorebirds have an abundant source of horseshoe crab eggs to feed upon when they stop to rest in Delaware Bay before moving north to their Canadian nesting areas. The shores of the Delaware Bay are an important spawning area for this species.

We look forward to continued coordination with the NRC as it moves forward with the development of the SEIS and the relicensing process. Should you have any questions, need additional information or would life to arrange a meeting to discuss the EFH consultation process or impacts to resources of concern to NMFS, please contact Karen Greene at 732 872-3023.

Sincerely,

Stanley W. Gorski
Field Offices Supervisor

cf: J. Crocker

Appendix E

Chronology of Environmental Review Correspondence

E. Chronology of Environmental Review Correspondence

This appendix contains a chronological listing of correspondence between the U.S. Nuclear Regulatory Commission (NRC) and external parties as part of its environmental review for Salem Nuclear Generating Station and Hope Creek Generating Station. All documents, with the exception of those containing proprietary information, are available electronically from the NRC's Public Electronic Reading Room found on the Internet at the following Web address: http://www.nrc.gov/reading-rm.html. From this site, the public can gain access to the NRC's Agencywide Document Access and Management System (ADAMS), which provides text and image files of NRC's public documents in ADAMS. The ADAMS accession number for each document is included below.

E.1 Environmental Review Correspondence

September 8, 2009	*Federal Register* notice: "Notice of Receipt and Availability of Application for Renewal of Hope Creek Generating Station for an Additional 20-year period". Federal Register, Vol.74. No. 172 (74 FR 46238) (ADAMS Accession No. ML092290801).
September 8, 2009	*Federal Register* notice: "Notice of Receipt and Availability of Application for Renewal of Salem, Units 1 and 2 Facility Operating License Nos. DPR-70 and DPR-75 for an Additional 20-year Period". Federal Register, Vol.74. No. 172, September 8, 2009 (74 FR 46238) (ADAMS Accession No. ML092150718).
September 18, 2009	PSEG Nuclear, Salem Nuclear Generating Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML092430232).
September 18, 2009	PSEG Nuclear, Hope Creek Generating Generating Station, Units 1 and 2, License Renewal Application (ADAMS Accession No. ML092430376).
October 15, 2009	Notice of Acceptability for Docketing of the Application and Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License No. NPF-57 for an Additional 20-Year Period, PSEG Nuclear, LLC, Hope Creek Nuclear Generating Station (ADAMS Accession No. ML092780147).
October 15, 2009	Notice of Intent to Prepare an Environmental Impact Statement and Conduct the Scoping Process for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Nuclear Generating Station (ADAMS Accession No. ML092740421).
October 23, 2009	Notice of Meeting to Discuss License Renewal Process and Environmental Scoping for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station, License Renewal Application Review (ADAMS Accession No. ML092870635).
October 25, 2009	Notice (email) sent the week of October 25, 2009, notifying the Delaware Tribal Headquarters of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010 (ADAMS

	Accession No. ML093090124).
October 25, 2009	Notice (email) sent the week of October 25, 2009, notifying the Ramapough Mountain Lenape (NJ) of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010 (ADAMS Accession No. ML093090124).
October 25, 2009	Notice (email) sent the week of October 25, 2009,notifying the Nanticoke Lenni-Lenape Indians of New Jersey of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010 (ADAMS Accession No. ML093090124).
October 25, 2009	Notice (email) sent the week of October 25, 2009, notifying the Powhatan Renape Nation (NJ) of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010 (ADAMS Accession No. ML093090124).
October 25, 2009	Notice (email) sent the week of October 25, 2009, notifying the Pocomoke Indian Nation (MD) of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010 (ADAMS Accession No. ML093090124).
October 25, 2009	Notice (email) sent the week of October 25, 2009, notifying The Nause-Waiwash Band of Indians, Inc. (MD) of the Salem-Hope Creek public Scoping Meeting to be held on November 5, 2010. (ADAMS Accession No. ML093090124).
November 5, 2009	Transcript of Salem & Hope Creek License Renewal Public Meeting, November 05, 2009, Pages 1-79 (ADAMS Accession No. ML093240195).
November 5, 2009	Transcript of Salem and Hope Creek License Renewal Process, Public Meeting: Evening Session November 05, 2009, Pages 1-63 (ADAMS Accession No. ML100471177).
November 5, 2009	Salem/Hope Creek Public Meeting Slides from November 5, 2009 (ADAMS Accession No. ML093380118).
November 12, 2009	Consultation letter to Jerry Douglas, Delaware Tribe of Indians, Delaware Tribal Headquarters, Bartlesville, OK, “Salem Nuclear Generating Stations, Units 1 and 2, and Hope Creek Generation Station, Unit 1, License Renewal Applications” (ADAMS Accession No. ML093090124).
November 24, 2009	Consultation letter to Mr. Timothy A. Slavin, SHPO, Delaware Division of Historical and Cultural Affairs, “Salem and Hope Creek License Renewal Applications Review” (ADAMS Accession No. ML093160444).
November 24, 2009	Consultation letter to Mr. J. Rodney Little, Maryland Historical Trust, “Salem and Hope Creek License Renewal Applications Review” (ADAMS Accession No. ML093160444).

November 24, 2009	Consultation letter to Mr. Daniel Saunders, New Jersey Historic Preservation Office, "Salem and Hope Creek License Renewal Applications Review" (ADAMS Accession No. ML093160444).
November 24, 2009	Consultation letter to Ms. Jean Cutler, Pennsylvania Bureau for Historic Preservation, "Salem and Hope Creek License Renewal Applications Review" (ADAMS Accession No. ML093160444).
December 23, 2009	Consultation letter to Ms. Patricia Kurkul, Regional Administrator, National Marine Fisheries Service Northeast Regional Office, "Request for List of Protected Species within the Area under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License Renewal Application Review" (ADAMS Accession No. ML093500057).
December 23, 2009	Consultation letter to Ms. Annette Scherer, Senior Fish & Wildlife Biologist (Endangered Species), U.S. Fish and Wildlife Service, New Jersey Field Office, "Request for List of Protected Species within the Area under Evaluation for the Salem and Hope Creek Nuclear Generating Stations License renewal Application Review", (ADAMS Accession No. ML093350019).
April 6, 2010	Salem, Units 1 & 2 - Corrections to the License Renewal Application Environmental Report (ADAMS Accession No. ML100980030).
April 6, 2010	Hope Creek Generating Station - Corrections to the License Renewal Application Environmental Report (ADAMS Accession No. ML100980029).
April 12, 2010	Request for Additional Information Regarding Severe Accident Mitigation Alternatives for Salem Nuclear Generating Station Units 1 and 2 (ADAMS Accession No. ML100910252).
April 16, 2010	Request for Additional Information Regarding The Review of the License Renewal Application for Salem Nuclear Generating Station, Units 1 and 2, and Hope Creek Generating Station (ADAMS Accession No. 100910367).
April 20, 2010	Hope Creek, SAMA Request for Additional Information (RAI) (ADAMS Accession No. ML100840225).

Appendix F

U.S. Nuclear Regulatory Commission Staff Evaluation of Severe Accident Mitigation Alternatives for Salem Nuclear Generating Station Units 1 and 2 In Support of License Renewal Application Review

F. U.S. Nuclear Regulatory Commission Staff Evaluation of Severe Accident Mitigation Alternatives for Salem Nuclear Generating Station Units 1and 2 in Support of License Renewal Application Review

F.1 Introduction

PSEG Nuclear, LLC, (PSEG) submitted an assessment of severe accident mitigation alternatives (SAMAs) for the Salem Nuclear Generating Station (SGS) as part of the environmental report (ER) (PSEG 2009). This assessment was based on the most recent Salem probabilistic risk assessment (PRA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 Version 2 (MACCS2) computer code, and insights from the Salem individual plant examination (IPE) (PSEG 1993) and individual plant examination of external events (IPEEE) (PSEG 1996). In identifying and evaluating potential SAMAs, PSEG considered SAMAs that addressed the major contributors to core damage frequency (CDF) and release frequency at SGS, as well as SAMA candidates for other operating plants that have submitted license renewal applications. PSEG initially identified 27 potential SAMAs. This list was reduced to 25 unique SAMA candidates by eliminating SAMAs that are not applicable to Salem due to design differences, have already been implemented at SGS, would achieve the same risk reduction results that had already been achieved at SGS by other means, or have excessive implementation cost. PSEG assessed the costs and benefits associated with each of the potential SAMAs and concluded in the ER that several of the candidate SAMAs evaluated are potentially cost-beneficial.

Based on a review of the SAMA assessment, the U.S. Nuclear Regulatory Commission (NRC) staff issued a request for additional information (RAI) to PSEG by letter dated April 12, 2010 (NRC 2010a) and, based on a review of the RAI responses, a request for RAI response clarification by teleconference dated July 29, 2010 (NRC 2010b). The staff's requests concerned the following:

- discussing internal and external review comments on the PRA model, including the impact of the Pressurized Water Reactor (PWR) Owner's Group PRA peer review comments on the SAMA analysis results;
- clarifying the development bases and assumptions for the Level 2 PRA model;
- additional details on the quality and implementation status of the SGS fire risk model;
- the SAMA screening process and additional potential SAMAs not previously considered; and

- further information on the costs and benefits of several specific candidate SAMAs.

PSEG submitted additional information in response to the NRC request by letters dated May 24, 2010 (PSEG 2010a) and August 18, 2010 (PSEG 2010b). In these response letters, PSEG provided the following:

- a listing of open gaps and “key findings” from the 2008 PRA peer review and an assessment of their impact on the SAMA analysis;
- clarification of Level 2 PRA modeling details and assumptions;
- further details on the SGS fire PRA model;
- analyses of additional SAMAs; and
- additional information regarding several specific SAMAs.

The licensee’s responses addressed the NRC staff’s concerns.

An assessment of SAMAs for SGS is presented below.

F.2 Estimate of Risk for Salem

PSEG’s estimates of offsite risk at SGS are summarized in Section F.2.1. The summary is followed by the NRC staff’s review of PSEG’s risk estimates in Section F.2.2.

F.2.1 PSEG’s Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the SGS Level 1 and 2 PRA model, which is an updated version of the IPE (PSEG 1993), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PRA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent SGS Level 1 and Level 2 PRA model available at the time of the ER, referred to as the Salem PRA (Revision 4.1, September 2008 model of record (MOR)). The scope of this Salem PRA does not include external events.

The SGS CDF is approximately 4.8×10^{-5} per year for internal events as determined from quantification of the Level 1 PRA model at a truncation of 1×10^{-11} per year. When determined from the sum of the containment event tree (CET) sequences, or Level 2 PSA model, the release frequency (from all release categories, which consist of intact containment, late release, and early release) is approximately 5.0×10^{-5} per year, also at a truncation of 1×10^{-11} per year. The latter value was used as the baseline CDF in the SAMA evaluations (PSEG 2009). The

CDF is based on the risk assessment for internally initiated events, which includes internal flooding. PSEG did not explicitly include the contribution from external events within the SGS risk estimates; however, it did account for the potential risk reduction benefits associated with external events by multiplying the estimated benefits for internal events by a factor of 2. This is discussed further in Sections F.2.2 and F.6.2.

The breakdown of CDF by initiating event is provided in Table F-1. As shown in this table, events initiated by loss of control area ventilation, loss of offsite power, and loss of service water are the dominant contributors to the CDF. PSEG identified that Station Blackout (SBO) contributes 8×10^{-6} per year, or 17 percent, to the total internal events CDF (PSEG 2010a).

Table F-1. SGS Core Damage Frequency for Internal Events (PSEG 2010a)

Initiating Event	**CDF[1] (per year)**	**% Contribution to CDF[2]**
Loss of Control Area Ventilation	1.8×10^{-5}	37
Loss of Off-site Power (LOOP)	8.1×10^{-6}	17
Loss of Service Water	6.6×10^{-6}	14
Internal Floods	4.5×10^{-6}	9
Transients	4.0×10^{-6}	8
Steam Generator Tube Rupture (SGTR)	2.7×10^{-6}	6
Loss of Component Cooling Water (CCW)	1.0×10^{-6}	2
Anticipated Transient Without Scram (ATWS)	7.4×10^{-7}	2
Loss of 125V DC Bus A	6.9×10^{-7}	1
Others (less than 1 percent each)[3]	1.8×10^{-6}	4
Total CDF (internal events)	$\mathbf{4.8 \times 10^{-5}}$	**100**

[1]Calculated from Fussel-Vesely risk reduction worth (RRW) provided in response to NRC staff RAI 1.e (PSEG 2010a).

[2]Based on Internal Events CDF contribution and total Internal Events CDF.

[3]CDF value derived as the difference between the total Internal Events CDF and the sum of the individual internal events CDFs calculated from RRW.

The Level 2 Salem PRA model that forms the basis for the SAMA evaluation is essentially a complete revision of the original IPE Level 2 model and conforms to current industry guidance. The Level 2 model utilizes a single CET containing both phenomenological and systemic events. The Level 1 core damage sequences are binned into accident classes which provide the interface between the Level 1 and Level 2 CET analysis. The CET is linked directly to the Level 1 event trees and CET nodes are evaluated using supporting fault trees and logic rules.

The result of the Level 2 PRA is a set of 11 release or source term categories, with their respective frequency and release characteristics. The results of this analysis for SGS are provided in Table E.3-6 of ER Appendix E (PSEG 2009). The categories were defined based on the timing of the release, the initiating event, whether feedwater is available, and the containment failure mode. The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. Source terms were developed for each of the 11 release categories using the results of Modular Accident Analysis Program (MAAP Version 4.0.6) computer code calculations (PSEG 2010a).

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mile radius) for the year 2040, emergency response evacuation modeling, and economic data. The core radionuclide inventory corresponds to the end-of-cycle values for SGS operating at 3632 MWt, which is five percent above the current licensed power level of 3,459 MWt. The magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In the ER, PSEG estimated the dose to the population within 80-kilometers (50-miles) of the SGS site to be approximately 0.78 person-Sievert (Sv) (78 person-roentgen equivalent man (rem)) per year. The breakdown of the total population dose by containment release mode is summarized in Table F-2. Containment bypass events (such as SGTR-initiated large early release frequency (LERF) accidents) and late containment failures without feedwater dominate the population dose risk at SGS.

Table F-2. Breakdown of Population Dose by Containment Release Mode

Containment Release Mode	Population Dose (Person-Rem[1] Per Year)	Percent Contribution[2]
Containment over-pressure (late)	42.9	55
Steam generator rupture	31.9	41
Containment isolation failure	2.3	3
Containment intact	0.2	<1
Interfacing system LOCA	0.6	<1
Catastrophic isolation failure	0.4	<1
Basemat melt-through (late)	negligible	negligible
Total[3]	**78.2**	**100**

[1]One person-rem = 0.01 person-Sv
[2]Derived from Table E.3-7 of the ER (PSEG 2009)
[3]Column totals may be different due to round off.

F.2.2 Review of PSEG's Risk Estimates

PSEG's determination of offsite risk at the SGS is based on the following three major elements of analysis:

- the Level 1 and 2 risk models that form the bases for the 1993 IPE submittal (PSEG 1993), and the external event analyses of the 1996 IPEEE submittal (PSEG 1996),
- the major modifications to the IPE model that have been incorporated in the SGS PRA, including a complete revision of the Level 2 risk model, and
- the MACCS2 analyses performed to translate fission product source terms and release frequencies from the Level 2 PRA model into offsite consequence measures (essentially this equates to a Level 3 PRA).

Each of these analyses was reviewed to determine the acceptability of the SGS's risk estimates for the SAMA analysis, as summarized below.

The NRC staff's review of the SGS IPE is described in an NRC report dated March 21, 1996 (NRC 1996). Based on a review of the original IPE submittal, responses to RAIs, and a revised IPE submittal, the NRC staff concluded that the IPE submittal met the intent of GL 88-20

(NRC 1988); that is, the licensee's IPE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities. Although no vulnerabilities were identified in the IPE, three improvements to plant and procedures were identified. Two of the improvements were revising SGS procedures related to interfacing systems loss of coolant accidents (ISLOCA) and the third was to install an isolation valve in the demineralized water line to be used to prevent flooding in the relay and switchgear rooms. All of these improvements are stated to have been implemented (PSEG 2009).

There have been eight revisions to the IPE model since the 1993 IPE submittal. A listing of the major changes made to the SGS PRA since the original IPE submittal was provided in the ER (PSEG 2009) and in response to an RAI (PSEG 2010a) and is summarized in Table F-3. A comparison of the internal events CDF between the 1993 IPE and the current PRA model indicates an increase of about 25 percent in the total CDF (from 6.4×10^{-5} per year to 4.8×10^{-5} per year).

Table F-3. SGS PRA Historical Summary (PSEG 2009)

PRA Version	Summary of Changes from Prior Model[2]	CDF[1] (per year)
1993	IPE Submittal	6.4×10^{-5}
Model 1.0 8/1996	- Updated plant and common cause data	5.1×10^{-5}
Model 2.0 8/1998	- Enhanced the service water system and reactor coolant pump (RCP) seal models - Added anticipated transients without trip (ATWT) mitigation system actuation circuitry (AMSAC) and valves for containment isolation system - Eliminated switchgear ventilation as a support system - Added ISLOCA logic	5.2×10^{-5}
Model 3.0 6/2002	- Incorporated resolution of 2001 Westinghouse Owner's Group (WOG) PRA certification comments - Added switchgear ventilation as a support system - Addressed HRA dependency issues, updated common-cause calculations, and adjusted initiating event fault tree logic - Modified how recovery actions were credited	5.2×10^{-5}
Model 3.1 7/2003	- Revised system models for charging pumps, emergency diesel generator (EDG), and AMSAC - Revised models for feedwater line break and steam-line break initiators - Added human actions to close the service water turbine header isolation valve(s)	4.1×10^{-5}
Model 3.2 3/2005	- Enhanced the internal flooding and offsite power recovery models - Revised models for the switchyard and service water crosstie between units	2.5×10^{-5}

PRA Version	Summary of Changes from Prior Model[2]	CDF[1] (per year)
	- Revised common cause failure data - Adjusted the auxiliary feedwater (AFW) pump failure rate	
Model 3.2a[3] 3/2006	- Removed recovery from loss of switchgear ventilation and for loss of primary coolant system (PCS) when the initiator causes loss of PCS - Removed credit for 1) cross-tying the Unit 2 positive displacement pump (PDP) with Unit 1, 2) cross-tying DC power supplies to power-operated relief valves (PORVs), 3) cross-tying power to diesel fuel oil transfer pumps, and 4) repair of failed EDGs - Updated the split fraction for a seal LOCA after loss of cooling - Reduced credit for 1) use of the gas turbine generator in several sequences, 2) use of a condensate pump for steam generator makeup, 3) an action to preserve service water availability, and 3) switching from the volume control tank (VCT) to the refueling water storage tank (RWST) - Removed unavailability of both trains of residual heat removal (RHR) - Revised operator actions for maintaining AFW suction source - Changed the loss of DC power initiator - Revised numerous human error probabilities - Added new failure mode for component cooling system (CCS) - Revised modeling of stuck open PORV for SBO and very small LOCA (VSLOCA) sequences - Revised model to require recovery following loss of CCW and failure to swap charging suction to the RWST - Changed split fractions in service water logic	6.2×10^{-5}
Model 4.0[3] 3/2008	- Completely revised and updated the human reliability analysis (HRA) - Updated failure and common-cause data - Updated model to better reflect post small LOCA operator actions - Updated model for loss of control area ventilation (CAV) initiator - Corrected model to have EDG C fail when EDGs A and B or their associated fuel oil transfer pumps fail - Updated the service water system and reactor coolant pump (RCP) seal system models - Reduced credit for use of GTG during grid-related LOOPs - Updated modeling of DC dependencies	4.5×10^{-5}
Model 4.1 9/2008	- Completely revised the SGS internal flooding analysis - Updated model for charging pump upon failure to operate minimum flow valves - Refined the HRA analyses for SGTR events	4.8×10^{-5}

[1]The IPE, Model 1.0, and Model 2.0 SGS PRAs were performed for both Units 1 and 2; the CDF values shown for these PRA versions are for the SGS unit having the highest internal events and internal flooding CDFs. Starting with Model 3.0, the SGS PRA was performed for Unit 1 only.

[2]Summarized from information provided in the ER and a response a NRC staff RAI (PSEG 2010).

[3]The internal flooding contribution is not included in the reported CDF.

The CDF values from the 1993 IPE (6.4×10^{-5} per year for Unit 1 and 6.0×10^{-5} per year for Unit 2) are in the middle range of the CDF values reported in the IPEs for Westinghouse four-loop plants. Figure 11.6 of NUREG-1560 shows that the IPE-based total internal events CDF for Westinghouse four-loop plants ranges from 2×10^{-6} per year to 2×10^{-4} per year, with an average CDF for the group of 6×10^{-5} per year (NRC 1997b). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for SGS (4.8×10^{-5} per year) are comparable to that for other plants of similar vintage that have updated their models to reflect completed hardware changes.

PSEG explained in the ER that the Salem PRA model is representative of Unit 1, that differences in system configuration and success criteria between Units 1 and 2 are minimal, and that plant-specific data are averaged between the two units. In response to an NRC staff RAI (PSEG 2010a), PSEG further clarified that there are currently no differences between Units 1 and 2 that are believed to be important from a risk perspective. The specific design differences are 1) the recirculation switchover on unit 1 is strictly manual whereas on Unit 2 it is semi-automatic and 2) one component cooling heat exchanger on Unit 1 is of a different design than its counterpart on Unit 2. PSEG also stated that future plant modifications that make the risk profile significantly different between the two units will be addressed by the PRA maintenance and update process. The NRC staff concurs that these design differences between Units 1 and 2 are not likely to impact the results of the SAMA evaluation and that use of Revision 4.1 of the Salem PRA model to represent Unit 2 is reasonable.

The NRC staff considered the peer reviews performed for the SGS PRA, and the potential impact of the review findings on the SAMA evaluation. In the ER (PSEG 2009) and in response to an NRC staff RAI (PSEG 2010a), PSEG described two industry peer reviews of the SGS PRA. The first, conducted by the Westinghouse Owners Group in February 2002, reviewed PRA Model Revision 3.2a. The second, conducted by the PWR Owners Group in November 2008, reviewed PRA Model Revision 4.1.

PSEG stated in the ER that all Level A and B (extremely important and important, respectively) facts and observations (F&Os) from the Westinghouse Owners Group peer review have been addressed (PSEG 2009).

The 2008 peer review of Model Revision 4.1 was performed using the Nuclear Energy Institute peer review process (NEI 2007) and the ASME PRA Standard (ASME 2005) as endorsed by the NRC in Regulatory Guide 1.200, Rev. 1 (NRC 2007). The final report for this peer review had not been completed when the SAMA analysis was performed. In response to an NRC staff RAI, PSEG provided a listing and discussion of eight “key” findings from the 2008 PWR Owners Group peer review (PSEG 2010a). A finding is an observation that is necessary to address to ensure 1) the technical adequacy of the PRA, 2) the capability/robustness of the PRA update process, and 3) the process for evaluating the necessary capability of the PRA technical elements (NEI 2007). Four of the findings were determined to have no impact on the SAMA analysis because it was either a documentation issue (one finding), the current treatment in the PRA model was determined to be conservative (one finding), the finding was determined to be in conflict with other requirements in the PRA standard which were met by the PRA (one finding), or no change to the model was determined to be necessary based on additional analysis (one finding). The other four findings were determined to have a non-significant impact on the SAMA analysis for the following reasons:

- Component availability did not include a contribution from surveillance testing. PSEG explained that component availability is based on Mitigating Systems Performance Index (MSPI) and Maintenance Rule data, which is believed to be accurate, and that any changes in failure rates resulting from a comparison of this data with expected unavailability due to test procedures and maintenance is expected to be non-significant.

- Events that occurred at conditions other than at-power operation or which resulted in controlled shutdown were not considered. PSEG explained that identification of initiating events did include a review of events other than at-power operations and that events occurring during shutdowns and non-power conditions which could have occurred at power were not excluded from the review.

- The SBO success paths following offsite power recovery do not address recovery and operation of required safety systems. PSEG explained that the likelihood of loss of offsite power (LOOP), followed by station blackout (SBO), followed by successful recovery of offsite power, and then followed by multiple equipment failures preventing long-term safe shutdown is very small and that, therefore, the current treatment of SBO is sufficient for the SAMA analysis.

- Omission of failure modes for the EDGs due to the use of only MSPI data and not all plant-specific data. PSEG explained that component availability is based on MSPI and Maintenance Rule data, which is believed to be reliable, and that any changes in failure rates resulting from a validation with other plant-specific data is expected to be non-significant.

In response to another NRC staff RAI to describe the results of the 2008 Peer Review, including the key findings, PSEG provided a listing and discussion of the resolution of the 72 supporting requirements (SRs) that did not meet Capability Category II or higher and that remain open in SGS PRA MOR Revision 4.3 (PSEG 2010b). The 2005 ASME PRA standard describes Capability Category II is described as follows: 1) the scope and level of detail has resolution and specificity sufficient to identify the relative importance of significant contributors at the component level including human actions, as necessary, 2) plant-specific data/models used for significant contributors, and 3) departures from realism will have small impact on the conclusions and risk insights as supported by good practices (ASME 2005). PSEG evaluated each of the 72 SRs for impact on the SAMA evaluation and concluded the following:

- Sixty-three SRs were documentation issues and have no impact on the SAMA analysis.
- Three issues related to plant specific and similar plants' initiating events, and consistency of nomenclature for failure data were determined to have no impact on the SAMA analysis because: 1) the finding is principally a documentation issue and the one event cited by the peer reviewer as being mis-classified was determined by PSEG to be appropriately classified (SR IE-A3), 2) PSEG determined that they made appropriate approximations for certain component/failure models where data were lacking (SR SY-A21), and 3) the finding has to do with a conservative modeling issue that does not impact the SAMA analysis (SR IE-C3).
- Six issues related to loss of an AC bus, grouping of initiating events, one particular human action, and miscalibration of standby equipment were determined to have minimal impact on the SAMA analysis because: 1) the referenced event is bounded by the current PRA model (SR IE-A1), 2) the issue relates to how initiating events are grouped (SRs IE-B3 and AS-A5), 3) the issue impacts only one specific human failure event (HFE) (SR SY-A16), or 4) the un-modeled pre-initiator human errors are viewed as having a low risk contribution (SRs HR-C3 and SY-B16).

PSEG further states that, overall, resolution of the SRs will have a minimal impact on the SAMA evaluation and is well within the uncertainty analysis discussed in Section F.6.2, and that all of the identified SRs that did not meet Capability Category II or higher will be reviewed for consideration during the next periodic update of the PRA model.

Based on the staff's review with respect to the requirements of the ASME PRA standard, the NRC staff considers PSEG's disposition of the peer review findings to be reasonable and that final resolution of the findings is not likely to impact the results of the SAMA analysis.

PSEG also stated that there have not been any further reviews of the SGS internal events PRA since the 2008 peer review of PRA Model Revision 4.1.

The NRC staff asked PSEG to identify any changes to the plant, including physical and procedural modifications, since Revision 4.1 of the Salem PRA model that could have a significant impact on the results of the SAMA analysis (NRC 2010). In response to the RAI (PSEG 2010a), PSEG explained that one design change and one procedural change have been made since PRA Model Revision 4.1 that have the potential to significantly change the PRA results. The design change allows the use of two small non-engineered safety feature (ESF) diesel generators to provide power for control and operation of switchyard breakers and to provide a backup source of power to station battery chargers. The procedure change included new procedural steps to provide forced flow of large quantities of outside air to areas supplied by the control area ventilation system. These plant changes resulted in a reduction in the SGS CDF. While the CDF for the updated SGS PRA model, designated as model of record Revision 4.3, was not provided in the RAI response, PSEG did provide the updated SGS release frequency of 2.2×10^{-5} per year, which is more than a 50 percent reduction from the 5.0×10^{-5} per year used in the SAMA analysis. The impact of this change on the SAMA analysis is discussed in Sections F.3.2 and F.6.2.

In the ER, PSEG explains that, in addition to peer reviews, other measures to ensure, validate, and maintain the quality of the SGS PRA include a formal qualification program for PRA staff, use of procedural guidance to perform PRA tasks, and a program to control PRA models and software. PSEG concludes that based on this quality control process, use of PRA Model Revision 4.1 for the SAMA evaluation was deemed appropriate.

Given that the PSEG internal events PRA model has been peer-reviewed and the peer review findings were judged to have minimal impact on the results of the SAMA analysis, and that PSEG has satisfactorily addressed NRC staff questions regarding the PRA, the NRC staff concludes that the internal events Level 1 PRA model is of sufficient quality to support the SAMA evaluation.

As indicated above, the current SGS PRA does not include external events. In the absence of such an analysis, PSEG used the SGS IPEEE to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences, as discussed below and in Section F.3.2.

The SGS IPEEE was submitted in November 1995 (PSEG 1996), in response to Supplement 4 of Generic Letter 88-20 (NRC 1991a). The submittal included a seismic PRA, a fire PRA, and a screening analysis for other external events. While no fundamental weaknesses or vulnerabilities to severe accident risk in regard to the external events were identified, several potential enhancements were identified as discussed below. In a letter dated May 21, 1999, (NRC 1999) NRC staff concluded that the submittal met the intent of Supplement 4 to Generic Letter 88-20, and that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities.

The SGS IPEEE seismic analysis utilized a seismic PRA following NRC guidance (NRC 1991a). The seismic PRA included: a seismic hazard analysis, a seismic fragility assessment, a seismic systems analysis, and quantification of seismic CDF.

The seismic hazard analysis estimated the annual frequency of exceeding different levels of ground motion. Seismic CDFs were determined for both the EPRI (EPRI 1989) and the Laurence Livermore National Laboratory (LLNL) (NRC 1994) hazard assessments. The seismic fragility assessment utilized the walkdown and screening procedures in EPRI's seismic margin assessment methodology (EPRI 1991). Fragility calculations were made for about 100 components and, using a screening criteria of median peak ground acceleration (pga) of 1.5 g which corresponds to a 0.5 pga high confidence low probability of failure (HCLPF) capacity, a total of 27 components remained after screening. The seismic systems analysis defined the potential seismic induced structure and equipment failure scenarios that could occur after a seismic event and lead to core damage. The SGS IPE event tree and fault tree models were used as the starting point for the seismic analysis but an explicit seismic event tree (SET) was used to delineate the potential successes and failures that could occur due to a seismic event. Quantification of the seismic models consisted of considering the seismic hazard curve with the appropriate structural and equipment seismic fragility curves to obtain the frequency of the seismic damage state. The conditional probability of core damage given each seismic damage state was then obtained from the IPE models with appropriate changes to reflect the seismic damage state. The CDF was then given by the product of the seismic damage state probability and the conditional core damage probability.

The seismic CDF resulting from the SGS IPEEE was calculated to be 9.5×10^{-6} per year using the LLNL seismic hazard curve and 4.7×10^{-6} per year using the EPRI seismic hazard curve. Both utilized the IPE internal events PRA, with a CDF of 6.4×10^{-5} per year for quantification of non-seismic failures. While the IPEEE indicated that the EPRI results were believed to be more realistic PSEG assumed a seismic CDF of 9.5×10^{-6} per year based on the LLNL seismic hazard curve in the development of the external events multiplier for purposes of the SAMA evaluation (PSEG 2009). In the ER, PSEG provided a listing and description of the top seven seismic core damage contributors. The dominant seismic core damage contributors for the LLNL seismic hazard curve, representing about 95 percent of the seismic CDF, are listed in Table F-4. The largest contributors to seismic CDF are seismic-induced LOOP caused by failure of the switchyard ceramic insulators combined with random failure of the EDGs and seismic-induced LOOP and failure of battery trains A and B caused by failure of the masonry block walls around the batteries. Since the use of the larger value provides more conservatism in the estimation of whether SAMAs may be cost-beneficial, the NRC staff agrees that the seismic CDF of 9.5×10^{-6} per year is reasonable for the SAMA analysis.

Table F-4. Dominant Contributors to the Seismic CDF (PSEG 2009)

Sequence ID	Seismic Sequence Description	CDF (per year)	% Contribution to Seismic CDF
17	OP: Seismically-Induced LOOP caused by failure of the switchyard ceramic insulators	2.9×10^{-6}	31

Sequence ID	Seismic Sequence Description	CDF (per year)	% Contribution to Seismic CDF
33	OP-DAB: Seismically-Induced LOOP and failure of battery trains A and B	2.0×10^{-6}	21
31	OP-SW: Seismically-Induced LOOP and failure of the service water system	1.3×10^{-6}	14
35	OP-IC: Seismically-Induced LOOP and failure of instrumentation and control capability and equipment in the main control room	1.2×10^{-6}	13
34	OP-DAB-DG: Same as 33 OP-DAB and failure of battery train C	7.7×10^{-7}	8
17F	OP-FW: Same as 17 OP and failure of containment fan coolers	5.4×10^{-7}	6
21F	OP-FW-FC: Same as 17F OP-FW and failure of auxiliary feed water (AFW)	2.9×10^{-7}	3

The SGS IPEEE did not identify any vulnerabilities due to seismic events but did identify three improvements to reduce seismic risk. These improvements are 1) procedural change to ensure long term alternate ventilation for the Auxiliary Building, 2) replacement of identified low ruggedness relays with higher seismic capacity relays, and 3) reinforcement of an 8-foot masonry wall in the 4kV switchgear room. PSEG clarified in response to an NRC staff RAI that the first two improvements have been implemented (PSEG 2010a). The third improvement is discussed further in Section F.3.2.

The SGS IPEEE fire analysis employed EPRI's fire-induced vulnerability evaluation (FIVE) methodology (EPRI 1993) followed by a PRA quantification of the unscreened compartments. The fire evaluation was performed on the basis of fire areas which are plant locations completely enclosed by 2-hour rated fire barriers and meeting the FIVE fire barrier criterion related to preventing propagation. Stage 1 consisted of qualitative screening of all plant fire areas to determine whether a fire could cause a plant shutdown or trip, or lead to loss of safe shutdown equipment. Stage 1 also consisted of quantitative screening performed by estimating whether an area's associated fire frequency in combination with the conditional core damage probability given by the loss of functions potentially impacted by the fire was less than the 1×10^{-6} per year. Based on qualitative and quantitative screening all but 38 fire areas were screened out. Stage 2 was to evaluate the remaining fire areas by modeling fire growth and propagation to determine the fire damage state for each fire area. Stage 3 was an evaluation of Sandia Fire Risk Scoping Study issues (NRC 1989) using the tailored walkdown approach provided in the FIVE methodology. Containment performance was also examined to evaluate the performance of containment systems and equipment following core damage resulting from a fire. The final stage was assessment of the functional effects on the plant for each fire damage state by developing explicit fire event trees to probabilistically assess unscreened areas. Probabilistic credit was given for automatic and manual fire suppression systems. Final quantification utilized FIVE fire data and refined conditional core damage probabilities (CCDPs) from the IPE internal events PRA. The resulting fire induced CDF was calculated to be 2.3×10^{-5} per year.

In the ER, PSEG provided a listing and description of the top ten fire core damage contributors. The dominant fire core damage contributors, representing about 99 percent of the fire CDF, are listed in Table F-5. The largest contributors to fire CDF are fires in the 460V Switchgear Rooms, Relay Room, and Control Rooms.

Subsequent to the IPEEE, SGS replaced the CO_2 suppression systems with water sprinkler systems in the 460V Switchgear Rooms, 4160V Switchgears Rooms, and Lower Electrical Penetration Area. In addition, the results of cable wrap tests suggested that the cable wrap would not perform as expected in some areas of the plant and, subsequent to the IPEEE, was removed and replaced. Because of the suppression system changes made to the three areas identified, PSEG did not consider the IPEEE results for these areas valid. PSEG reassessed the fire CDF for these areas using PRA insights from an interim SGS fire model. If the interim SGS fire model showed a higher CDF for any of these three areas, the higher CDF was used for the SAMA analysis. This was the case for the 460V Switchgear Rooms and the Lower Electrical Penetration Area. The fire CDF from the interim SGS fire model for these two fire areas are provided in Table F-5. These insights increased the total fire CDF to 3.8×10^{-5} per year, which was used in the SAMA analysis.

The NRC staff asked PSEG to provide additional information about the interim SGS fire model and, specifically, why it was not used for the SAMA analysis beyond the three areas discussed (NRC 2010a). In response to the RAI, PSEG explained that after the completion of the IPEEE, there was an effort made to develop a fire PRA. This resulted in a partially complete “interim SGS fire model.” However, the interim SGS fire model was never integrated into the internal events PRA model of record (which at the time was Revision 3) and was essentially abandoned because of the forthcoming NUREG/CR-6850 fire PRA development guidance that would render the SGS fire modeling methodology obsolete.

Table F-5. Important Fire Areas and Their Contribution to Fire CDF (PSEG 2009)

Fire Area Description	CDF[1] (per year)	% Contribution to Fire CDF
460V Switchgear Rooms	1.3×10^{-5}	34

Fire Area Description	CDF[1] (per year)	% Contribution to Fire CDF
Relay Room	7.2×10^{-6}	19
Control Rooms, Peripheral Room, and Ventilation Rooms	7.0×10^{-6}	18
4160V Switchgear Room	3.4×10^{-6}	9
Lower Electrical Penetration Area	3.2×10^{-6}	8
Upper Electrical and Piping Penetration Areas	1.3×10^{-6}	3
Reactor Plant Auxiliary Equipment Area (84B)	1.1×10^{-6}	3
Turbine and Service Buildings	6.4×10^{-7}	2
Service Water Intake	4.2×10^{-7}	1
Reactor Plant Auxiliary Equipment Area (100C)	2.9×10^{-7}	1

[1]CDF reported for the 460V Switchgear Rooms and 4160V Switchgear Rooms is from the interim SGS fire model. All other CDFs are from the IPEEE.

The SGS IPEEE did not identify any vulnerabilities due to fire events but did identify two improvements to reduce fire risk. These improvements are 1) procedural change to enhance cooling in the switchgear and control areas in the event of a fire and 2) procedural change for the control of transient combustibles in the turbine building. PSEG clarified in response to an NRC staff RAI that the two suggested improvements have been implemented (PSEG 2010a).

As discussed previously, PSEG identified in the ER that SGS has replaced CO_2 fire suppression systems with water sprinkler systems in three areas of the plant since the IPEEE and that cable wrap has been removed and replaced in several areas of the plant since the IPEEE. The NRC staff asked PSEG if any other fire-related improvements have been made since the IPEEE (NRC 2010a). In response to the RAI, PSEG indicated that the following improvements had been made since the IPEEE: 1) the ventilation system and strategy for maintaining viable working conditions was revised for the 4160V Switchgear Room and the Upper Electrical and Piping Penetration Areas and 2) the maintenance shop was eliminated in the Turbine and Service Buildings in order to reduce the initiating event frequency of fires that would damage the cables for the emergency 4kV buses (PSEG 2010a).

In the ER, PSEG states that an effective comparison between the internal events PRA results and the fire analysis results is not possible because neither the plant response model or the fire modeling methodology used in the IPEEE is up-to-date. PSEG also identified areas where fire CDF quantification may introduce different levels of uncertainty than expected in the internal events PRA and identified a number of conservatisms in the IPEEE fire analysis, including:

- A revised NRC fire events database indicates a trend toward lower frequency and less severe fires than assumed in the SGS IPEEE.

- Bounding fire modeling assumptions are used for many fire scenarios. For example, all equipment in a cabinet is damaged for any fire within a cabinet, regardless of whether it is suppressed. Other examples are provided in the ER.

- Because of a lack of industry experience with regard to crew performance during the types of fires modeled in the fire PRA, the characterization of crew actions in the fire PRA is generally conservative.

PSEG's conclusion is that while there are both conservative and potentially non-conservative factors included in the IPEEE fire model, the IPEEE is judged to have more conservative bias than the internal events model.

Although the arguments regarding the conservatisms in the fire analysis are presented in the ER, PSEG used the modified IPEEE fire CDF of 3.8×10^{-5} per year in the SAMA analysis rather than some reduced value. Considering the above discussion, the conservatisms in the IPEEE fire analysis as currently understood, and the response to the NRC staff RAIs, the NRC staff concludes that the fire CDF of 3.8×10^{-5} per year is reasonable for the SAMA analysis.

The SGS IPEEE analysis of high winds, floods, and other external (HFO) events followed the progressive screening method defined in NUREG-1407 (NRC 1991b). While SGS is not considered a 1975 Standard Review Plan (SRP) plant, aspects of its licensing basis do conform to the 1975 SRP criteria because SGS is co-located with Hope Creek Generating Station (HCGS), which does meet the 1975 SRP criteria (PSEG 1996). For those events that are based on the location of the site, and not plant-specific features, the 1975 SRP criteria was used for the HFO screening analysis. Progressively more quantitatively based methods were employed for those events that could not be shown to conform to the 1975 SRP criteria. The IPEEE concluded that all HFO events either complied with the 1975 SRP criteria or that their predicted CDF was below the IPEEE screening criteria (i.e. $< 1 \times 10^{-6}$ per year). For the SAMA analysis, PSEG assumed a CDF contribution of 1×10^{-6} per year for each of high winds, external floods, transportation and nearby facilities, detritus, and chemical releases for a total HFO CDF contribution of 5×10^{-6} per year (PSEG 2009).

Although the SGS IPEEE did not identify any vulnerabilities due to HFO events, three improvements to reduce risk were identified. These improvements are 1) modify the circulating water intake structure to protect against detritus (blockage), 2) make improvements to protect against water ingress pathways for external flooding events, and 3) improve the hold downs for hydrogen tanks to protect against tornados. PSEG clarified in response to an NRC staff RAI that the first two suggested improvements have been implemented (PSEG 2010a). The third improvement is discussed further in Section F.3.2.

A review of transportation and nearby facility accidents confirmed that there were no severe accident vulnerabilities from these accidents. Accidents from river traffic, including detonation of explosives and impacts with the Service Water intake structure, were examined in the IPEEE. The IPEEE concluded that the detonation of explosives related to river shipping would not threaten the integrity of the safety structures even under the conditions present during the performance of the IPEEE. In addition, the potential for an impact on the Service Water intake structure was estimated to be on the order of 1E-07 per yr and it was excluded from further review in the IPEEE. Subsequent changes to the shipping procedures and exclusion zones since the IPEEE have reduced the potential for these types of events to occur. ,Given that the potential averted cost-risk associated with an event with a frequency of 1E-07 per yr is only about $16,000 (assuming core damage occurs at that frequency), no SAMAs are suggested to address river shipping hazards.

The NRC staff asked about the status and potential impact on the SAMA analysis of a liquefied natural gas (LNG) terminal planned for Logan Township, New Jersey, upstream on the Delaware River from the SGS site (NRC 2010a). In response to the RAI, PSEG discussed the current status of the LNG terminal as well as the regulatory controls for LNG marine traffic and LNG ship design and the safety record of LNG shipping (PSEG 2010a). The LNG terminal remains in the planning stage and no construction has begun. Further, the state of Delaware has denied applications for several required environmental permits and approvals. PSEG concluded that based on the regulatory process and controls for assuring the safety and security of LNG ships, the safety record of LNG ships, and the uncertainty of the planned terminal, consideration of potential SAMAs associated with the possible future terminal is not warranted. The NRC staff agrees with this conclusion.

Based on the aforementioned results, the external events CDF is approximately equal to the internal events CDF (based on a seismic CDF of 9.5×10^{-6} per year, a fire CDF of 3.8×10^{-5} per year, an HFO CDF of 5.0×10^{-6} per year, and an internal events CDF of 5.0×10^{-5} per year used in the SAMA analysis). Accordingly, the NRC staff concurred with SGS's conclusion that the total CDF (from internal and external events) would be approximately 2 times the internal events CDF. In the SAMA analysis submitted in the ER, PSEG doubled the benefit that was derived from the internal events model to account for the combined contribution from internal and external events. The NRC staff agrees with the licensee's overall conclusion concerning the multiplier used to represent the impact of external events and concludes that the licensee's use of a multiplier of 2 to account for external events is reasonable for the purposes of the SAMA evaluation. This is discussed further in Section F.6.2.

The NRC staff reviewed the general process used by PSEG to translate the results of the Level 1 PRA into containment releases, as well as the results of the Level 2 analysis, as described in the ER and in response to NRC staff RAIs (PSEG 2010a). The current Level 2 model is essentially a complete revision of the IPE Level 2 model. In response to an NRC staff RAI, related to the history of the Level 2 model, PSEG stated that the IPE Level 2 model was abandoned, with the exception of LERF, with Revision 3 of the SGS PRA model and that the Level 2 model was recreated incorporating current industry guidance as part of the transition from Revision 3 to Revision 4 of the PRA model (PSEG 2010a).

The current SGS Level 2 model utilizes a single CET containing both phenomenological and systemic events. The Level 1 core damage sequences are grouped into core damage accident classes, or plant damage states (PDSs), with similar characteristics. The PDSs are defined based on the following attributes: (1) reactor coolant system (RCS) pressure (high or low), (2) containment isolation status, (3) containment bypass status, (4) containment bypass via an unisolated steam generator tube rupture (SGTR), (5) containment bypass via an unisolated, large ISLOCA, (6) containment spray operation mode, (7) containment fan cooler operation, and (8) refueling water storage tank (RWST) injection. All of the sequences in an accident class are then input to the CET by linking the level 1 event tree sequences with the level 2 CET. The CET is analyzed by the linking of fault trees that represent each CET node. Whenever possible the fault trees utilized in the Level 1 analysis are utilized in the CET to propagate dependencies. In response to an NRC staff RAI, PSEG states that the Level 1 and Level 2 models are integrated in that the Level 1 sequences are directly passed to the Level 2 model in the software through the Level 1 sequence fault trees (PSEG 2010a). Twenty-three distinct CET end states or sequences result.

Section E.2.2.3 of the ER describes each of the top events of the CET and states that branch point probabilities for each top event are based on previous SGS Level 2 analyses, recent accident progression research, and similar analyses for other nuclear plants. The NRC staff requested that PSEG describe how the branch point probabilities were developed specifically for top events RCS Depressurization and Containment Heat Removal (NRC 2010a). In response to the RAI, PSEG clarified that top event RCS Depressurization consists of the combination of an existing human action from the human reliability analysis (HRA) and the fault tree for power-operated relief valve (PORV) operation (PSEG 2010a). The Containment Heat Removal top event is determined by specific Level 2 system models for containment fan cooler units (CFCUs) and containment spray (CS), either of which can be used for containment heat removal at SGS.

Each CET end state represents a radionuclide release to the environment and is assigned to a release category based on timing of release, the initiating event, whether feedwater is available, and the containment failure mode. Three general release categories are defined: intact containment, late release, and early release. These are further divided into eleven detailed release categories based on the above attributes, as defined in Section E.2.2.6 of the ER.

The frequency of each release category was obtained by summing the frequency of the contributing CET end states. The release characteristics for each release category were developed by using the results of Modular Accident Analysis Program (MAAP Version 4.0.6) computer code calculations (PSEG 2010a). Representative MAAP cases for each release category were chosen to either represent the most likely initiators in the release category (intact containment and late release categories) or to conservatively bound the consequences of the release (early release categories). The NRC questioned why PSEG did not also use representative cases that bound the consequences for the late release categories (NRC 2010a). In response to the RAI, PSEG stated that, because the late release categories take more time to evolve than the early release categories, the late release categories are less affected by the initial accident conditions and so result in more uniform consequences than the early release categories (PSEG 2010a). Since the accident sequences assigned to the late release categories yielded similar consequences, PSEG selected representative MAAP cases that represented the most likely initiators within those release categories. The release categories, their frequencies, and release characteristics are presented in Tables E.3-5 and E.3-6 of Appendix E to the ER (PSEG 2009).

The total Level 2 release frequency is of 5.0×10^{-5} per year, which is about 4 percent higher than the internal events CDF of 4.8×10^{-5} per year. The ER states that this difference is due to truncation of low probability sequences and inclusion of non-minimal Level 1 sequences. The NRC staff considers that use of the release frequency rather than the Level 1 CDF will have a negligible impact on the results of the SAMA evaluation because the external event multiplier and uncertainty multiplier used in the SAMA analysis (discussed in Section F.6.2) have a much greater impact on the SAMA evaluation results than the small error arising from the model quantification approach.

The revised SGS Level 2 PRA model was included in the 2008 PWR Owner's Group peer review discussed above. While none of the eight key findings had to do with the Level 2 analysis, eight LERF analysis SRs did not meet Capability Category II or higher and remain open in SGS PRA MOR Revision 4.3 (PSEG 2010b). PSEG determined that all eight of these findings were documentation issues that did not impact the SAMA analysis. As any associated technical aspects had been resolved, the NRC staff agrees with PSEG's characterization as documentation issues.

Based on the NRC staff's review of the Level 2 methodology, that PSEG has adequately addressed NRC staff RAIs, and that the Level 2 model was reviewed in more detail as part of the 2008 PWR Owners Group peer review and there were no findings that impacted the SAMA analysis, the NRC staff concludes that the Level 2 PRA provides an acceptable basis for evaluating the benefits associated with various SAMAs.

The NRC staff reviewed the process used by PSEG to extend the containment performance (Level 2) portion of the PRA to an assessment of offsite consequences (essentially a Level 3

PRA). This included consideration of the source terms used to characterize fission product releases for the applicable containment release categories and the major input assumptions used in the offsite consequence analyses. The MACCS2 code was utilized to estimate offsite consequences. Plant-specific input to the code includes the source terms for each source term category and the reactor core radionuclide inventory (both discussed above), site-specific meteorological data, projected population distribution within an 80-kilometer (50-mile) radius for the year 2040, emergency evacuation modeling, and economic data. This information is provided in Section E.3 of Appendix E to the ER (PSEG 2009).

PSEG used the MACCS2 code and a core inventory from a plant specific calculation at end of cycle to determine the offsite consequences of activity release. In response to an NRC staff RAI, PSEG stated that the MACCS2 analysis was based on the core inventory used in the February 2006 NRC-approved Alternate Source Term for SGS (PSEG 2010a). As indicated in the ER, the reactor core radionuclide inventory used in the consequence analysis was based on a thermal power of 3632 MWt, which is 5 percent higher than the current licensed thermal power of 3459 MWt for SGS. In response to an NRC staff RAI, PSEG stated that the higher thermal power was used to provide margin for a future power uprate (PSEG 2010a).

All releases were modeled as being from the top of the reactor containment building and at low thermal content (ambient). Sensitivity studies were performed on these assumptions and indicated little or no change in population dose or offsite economic cost. Assuming a ground level release decreased dose risk and cost risk by 8 percent and 7 percent, respectively. Assuming a buoyant plume decreased dose risk and cost risk by 1 percent or less. Based on the information provided, the staff concludes that the release parameters utilized are acceptable for the purposes of the SAMA evaluation.

PSEG used site-specific meteorological data for the 2004 calendar year as input to the MACCS2 code. The development of the meteorological data is discussed in Section E.3.7 of Appendix E to the ER. The data were collected from onsite and local meteorological monitoring systems. Sensitivity analyses using MACCS2 and the meteorological data for the years 2005 through 2007 show that use of data for the year 2004 results in the largest dose and economic cost risk. Missing meteorological data was filled by (in order of preference): using data from the backup met pole instruments (10-meter), using corresponding data from another level of the main met tower, interpolation (if the data gap was less than 6 hours), or using data from the same hour and a nearby day (substitution technique). The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for use by MACCS2. The NRC staff notes that previous SAMA analyses results have shown little sensitivity to year-to-year differences in meteorological data and concludes that the use of the 2004 meteorological data in the SAMA analysis is reasonable.

The population distribution the licensee used as input to the MACCS2 analysis was estimated for the year 2040 using year 1990 and year 2000 census data as accessed by SECPOP2000 (NRC 2003) as a starting point. In response to an NRC staff RAI, PSEG stated that the transient population was included in the 10-mile EPZ, and in the population projection (PSEG 2010a). A ten year population growth rate was estimated using the year 1990 to year 2000 SECPOP2000 data and applied to obtain the distribution in 2040. The baseline population was determined for each of 160 sectors, consisting of sixteen directions for each of ten concentric distance rings to a radius of 50 miles surrounding the site. The SECPOP2000 census data from 1990 and 2000 were used to determine a ten year population growth factor for each of the concentric rings. The population growth was averaged over each ring and applied uniformly to all sectors within each ring. The NRC staff requested PSEG provide an assessment of the impact on the SAMA analysis if a wind-direction weighted population estimate for each sector were used (NRC 2010a). In response to the RAI, PSEG stated that the impacts associated with angular population growth rates on population dose risk and offsite economic cost risk are minimal and bounded by the 30 percent population sensitivity case (PSEG 2010a). This is based on the relatively even wind distribution profile surrounding the site, the tendency for lateral dispersion between sectors, and the use of mean values in the analysis. A sensitivity study was performed for the population growth at year 2040. A 30 percent increase in population resulted in a 30 percent increase in dose risk and a 29 percent increase in cost risk. In response to an NRC staff RAI, PSEG stated that the radial growth rates used in the MACCS2 analysis provides a more conservative population growth estimate than using 'whole county' data for averaging. PSEG also identified that the population sensitivity case of 30 percent growth was approximately equivalent to adding 6.8 percent to the 10-year growth rate (PSEG 2010a). The NRC staff considers the methods and assumptions for estimating population reasonable and acceptable for purposes of the SAMA evaluation.

The emergency evacuation model was modeled as a single evacuation zone extending out 16 kilometers (10 miles) from the plant (the emergency planning zone – EPZ). PSEG assumed that 95 percent of the population would evacuate. This assumption is conservative relative to the NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone. The evacuated population was assumed to move at an average radial speed of approximately 2.8 meters per second (6.3 miles per hour) with a delayed start time of 65 minutes after declaration of a general emergency (KLD 2004). A general emergency declaration was assumed to occur at the onset of core damage. The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions. It is noted that the longest evacuation time presented in the study (i.e., full 10 mile EPZ, winter snow conditions, 99th percentile evacuation) is 4 hours (from the issuance of the advisory to evacuate). Sensitivity studies on these assumptions indicate that there is minor impact to the population dose or offsite economic cost by the assumed variations. The sensitivity study reduced the evacuation speed by 50 percent to 1.4 m/s. This change resulted in a 4 percent increase in population dose risk and no change in offsite economic cost risk. The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Site specific agriculture and economic parameters were developed manually using data in the 2002 National Census of Agriculture (USDA 2004) and from the Bureau of Economic Analysis (BEA 2008) for each of the 23 counties surrounding SGS, to a distance of 50 miles. Therefore, recently discovered problems in SECPOP2000 do not impact the SGS analysis. The values used for each of the 160 sectors were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using data in the 2002 National Census of Agriculture (USDA 2004) and the Bureau of Economic Analysis (BEA 2008). Food ingestion was modeled using the new MACCS2 ingestion pathway model COMIDA2 (NRC 1998). For SGS, less than one percent of the total population dose risk is due to food ingestion.

In addition, generic economic data that is applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 1.96, representing cost escalation from 1986 to April 2008 was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

The NRC staff concludes that the methodology used by PSEG to estimate the offsite consequences for SGS provides an acceptable basis from which to proceed with an assessment of risk reduction potential for candidate SAMAs. Accordingly, the NRC staff based its assessment of offsite risk on the CDF and offsite doses reported by PSEG.

F.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by PSEG are discussed in this section.

F.3.1 Process for Identifying Potential Plant Improvements

PSEG's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- Review of the most significant basic events from the current, plant-specific PRA and insights from the SGS PRA group,
- Review of potential plant improvements identified in, and original results of, the SGS IPE and IPEEE,

- Review of SAMA candidates identified for license renewal applications for six other U.S. nuclear sites, and
- Review of generic SAMA candidates from NEI 05-01 (NEI 2005) to identify SAMAs that might address areas of concern identified in the SGS PRA.

Based on this process, an initial set of 27 candidate SAMAs, referred to as Phase I SAMAs, was identified. In Phase I of the evaluation, PSEG performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- The SAMA is not applicable to SGS due to design differences
- The SAMA has already been implemented at SGS,
- The SAMA would achieve results that have already been achieved at SGS by other means, or
- The SAMA has estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at SGS.

Based on this screening, two SAMAs were eliminated leaving 25 for further evaluation. The results of the Phase I screening analysis is given in Table E.5-3 of Appendix E to the ER. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table E.6-1 of Appendix E to the ER. In Phase II, a detailed evaluation was performed for each of the 25 remaining SAMA candidates, as discussed in Sections F.4 and F.6 below. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of 2, as previously discussed.

F.3.2 Review of PSEG's Process

PSEG's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events, but also included explicit consideration of potential SAMAs for important fire and seismic initiated core damage sequences. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from risk reduction worth (RRW) perspectives at SGS, and included selected SAMAs from prior SAMA analyses for other plants.

PSEG provided a tabular listing of the Level 1 PRA basic events sorted according to their RRW (PSEG 2009). SAMAs impacting these basic events would have the greatest potential for reducing risk. PSEG used a RRW cutoff of 1.01, which corresponds to about a one percent change in CDF given 100-percent reliability of the SAMA.[1] This equates to a benefit of

[1] Subsequently, PSEG extended the review down to a RRW of 1.006 based on the estimated cost of a procedure change per unit, as discussed below.

approximately $164,000 (after the benefits have been multiplied by a factor of 2 to account for external events).[2] PSEG also provided and reviewed the Level 2 PRA basic events, down to a RRW of 1.01, for the release categories contributing over 94 percent of the population dose-risk. The Level 2 basic events for the remainder of the release categories were not included in the review so as to prevent high frequency-low consequence events from biasing the importance listing. All of the basic events on the Level 1 and 2 importance lists were addressed by one or more of the SAMAs (PSEG 2009). As a result of the review of the Level 1 and Level 2 basic events, 19 SAMAs were identified.

The NRC staff requested PSEG to extend the review of the Level 1 and 2 basic events down to a RRW threshold of 1.003, which equates to a benefit of approximately $50,000, the assumed cost of a procedural change at SGS (NRC 2010a).[3] In response to the RAI, PSEG provided revised Level 1 and Level 2 importance lists using SGS PRA model of record Revision 4.3, which was discussed in Section F.2.2, and extended the review of the basic events down to an RRW of 1.006, which equates to a benefit of about $47,000 using PRA Revision 4.3. The review identified the following three additional SAMAs associated with new basic events added to the importance lists (PSEG 2010a):

- SAMA 30 – Automatic Start of Diesel-Powered Air Compressor
- SAMA 31 – Fully Automate Swapover to Sump Recirculation
- SAMA 32 – Enhance Flood Detection for 100-foot Auxiliary Building and Enhance Procedural Guidance for Responding to Internal Floods

A Phase II detailed evaluation was performed for each of these additional SAMAs, which is discussed in Section F.6.2.

The NRC staff asked PSEG to clarify the appropriateness of determining importance factors, and SAMAs, for initiators that are identified as flag events having an assigned probability of 1.0 (NRC 2010a). PSEG explained in response to the RAI that fault trees were developed for several loss of support system initiating events (PSEG 2010a). Those events that lead to the loss of a support system and are responsible for causing the modeled initiating event were identified as flag events. These events are representative of that initiating event's contribution

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[2] NUREG/BR-0184 provides calculational techniques by which reductions in risk can be equated to monetary values. The reverse calculation can convert monetary values, such as the cost of a procedure, to a risk reduction for the specific plant under consideration. In this way, $164,000 equate to a RRW of 1.01, representing the potential to reduce risk by 1%. The subsequent use of a RRW of 1.006 represents the potential to reduce risk by 0.6% (NRC 1997a).

[3] Per site, the estimated cost of a procedure change is $100,000. Hope Creek uses this value since it is a single-unit site. Salem has two units, so this cost is halved per unit.

to CDF and were therefore considered appropriate by PSEG for risk ranking. PSEG further clarified that events whose failure leads to the occurrence of the modeled initiating event will also be listed in the importance list ranking and that the flag probability was therefore set to 1.0 to determine the appropriate CDF contribution of the cutsets. The RRW calculated for these flag events therefore correctly measures the risk significance of the initiating event modeled in this manner.

The NRC staff also asked PSEG to clarify the significance of determining importance factors, and SAMAs, for two split fraction events identified in the importance listing: “RCS-SLOCA-SPLIT” and “MFI-UNAVAILABLE” (NRC 2010a). PSEG explained in response to the RAI that the first event, “RCS-SLOCA-SPLIT,” is a flag event that indicates those cutsets in which an RCP seal LOCA has occurred and that the second event, “MFI-UNAVAILABLE,” is the conditional probability that the main feedwater system is unavailable given that a reactor trip signal has been generated, irrespective of whether an ATWS condition exists (PSEG 2010a). Because the first event is a flag event, it was assigned a probability of 1.0. SAMA 6, “Enhance Flood Detection for 84’ Auxiliary Building and Enhance Procedural Guidance for Responding to Service Water Flooding,” was identified because isolating a service water rupture early could help prevent the conditions that can lead to an RCP seal LOCA. The second event was assigned a conditional probability of 0.3. SAMA 14, “Expand ATWS Mitigation System Actuation Circuitry (AMSAC) Function to Include Backup Breaker Trip on Reactor Protection System (RPS) Failure,” was identified to use the AMSAC system to provide a redundant trip signal to help mitigate ATWS events. In over 60 percent of the scenarios in which MFI-UNAVAILABLE is a contributor, AMSAC maintenance is also a contributor. By mitigating ATWS events, SAMA 14 also mitigates scenarios having this combination of events.

PSEG reviewed the cost-beneficial Phase II SAMAs from prior SAMA analyses for five Westinghouse PWR and one General Electric BWR sites. PSEG’s review determined that all of the Phase II SAMAs reviewed were either already represented by a SAMA identified from the Level 1 and 2 importance list reviews, are already addressed by other means, have low potential for risk reduction at SGS, or were not applicable to the SGS design. This review resulted in no additional SAMAs being identified.

The NRC staff asked PSEG to review the cost beneficial SAMAs identified in the NRC-issued NUREG-1437 reports for each of the six nuclear sites and to provide an assessment any additional cost-beneficial SAMAs identified during these reviews for applicability to SGS (NRC 2010a). In response to this RAI, PSEG reviewed the cost-beneficial SAMAs identified in the NUREG-1437 reports and concluded the cost-beneficial SAMA either 1) was already identified and evaluated in the ER, 2) was already implemented at SGS, or 3) would not reduce SGS risk (PSEG 2010a). No additional SAMAs were identified from this review.

PSEG considered the potential plant improvements described in the IPE in the identification of plant-specific candidate SAMAs for internal events. Review of the IPE lead to no additional

SAMA candidates since the three improvements identified in the IPE have already been implemented at SGS (PSEG 2009).

As a sensitivity case to SAMA 5, PSEG identified and evaluated SAMA 5A, “Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries.” This SAMA only addresses cases in which RCP seals remain intact, which occurs in a majority of the SBO scenarios. PSEG performed a Phase II evaluation of SAMA 5A, which is in addition to the Phase II evaluations performed for the 25 SAMAs discussed above that were not screened during the Phase I evaluation.

Based on this information, the NRC staff concludes that the set of SAMAs evaluated in the ER, together with those identified in response to NRC staff RAIs, addresses the major contributors to internal event CDF.

Although the IPEEE did not identify any fundamental vulnerabilities or weaknesses related to external events, the ER identified three improvements related to external events (PSEG 2009). The NRC staff noted that the IPEEE safety evaluation report (NRC 1999) identified five total improvements related to external events and requested PSEG review these improvements for potentially additional SAMAs (NRC 2010a). In response to the RAI, PSEG reviewed the five suggested improvements and reassessed the three improvements originally evaluated in the ER (PSEG 2010a). As a result of this review, two improvements related to fire events, three improvements related to seismic events, and three improvements related to HFO events were identified. The two suggested fire-related improvements have been implemented, two of the seismic-related improvements have been implemented, and two of the HFO-related improvements have been implemented. The remaining two improvements that have not been implemented are as follows:

- Seismic-related improvement – reinforcement of an 8-foot masonry wall in the 4kV switchgear room. PSEG described the results of an evaluation that determined there was no interaction between the wall and the switchgear bus during a seismic event and subsequent implementation of a corrective action to revise the associated calculation to clarify the lack of interaction. Based on this, PSEG concluded that reinforcement of the masonry wall was not necessary and no SAMA is suggested (PSEG 2010a).

- HFO-related improvement – improve hold downs for the hydrogen tanks to protect against tornados. In response to the RAI, PSEG performed a walk down of the hydrogen racks and determined that the IPEEE suggested improvements to the Unit 2 racks to make the design consistent with the Unit 1 racks was not implemented as indicated in the ER. PSEG further noted that the IPEEE states that these hydrogen tanks “will not have any significant impact on safety structures.” Based on this, PSEG concluded that, while the suggested change was prudent, it would not reduce plant risk and no SAMA is suggested.

In the ER PSEG also identified three post IPEEE site changes to determine if they could impact the IPEEE results and possibly lead to a SAMA. From this review, one plant change to replace CO_2 fire suppression with water sprinkler systems was determined to have an impact on fire CDF, which was discussed in Section F.2.2. No additional SAMAs were identified from this review.

In a further effort to identify external event SAMAs, PSEG reviewed the top 10 fire areas contributing to fire CDF based on the results of the IPEEE and interim SGS fire PRA models. These areas are all of the SGS fire areas having a maximum benefit equal to or greater than approximately $50,000, which is the approximate value of implementing a procedure change at a single unit at SGS. The maximum benefit for a fire area is the dollar value associated with completely eliminating the fire risk in that fire area, which is discussed in Section F.6.2. SAMAs having an implementation cost of less than that of a procedure change, or $50,000, are unlikely. As a result of this review, PSEG identified five Phase I SAMAs to reduce fire risk. The SAMAs identified included both procedural and hardware alternatives (PSEG 2009). The NRC staff concludes that the opportunity for fire-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, fire-related SAMA candidates.

For seismic events, PSEG reviewed the top seven seismic sequences contributing to seismic CDF based on the results of the IPEEE seismic PRA model. These areas are all of the SGS seismic sequences having a benefit equal to or greater than approximately $50,000, which is the approximate value of implementing a procedure change at a single unit at SGS. The maximum benefit for a seismic sequence is the dollar value associated with completely eliminating the seismic risk for that sequence, which is discussed in Section F.6.2. SAMAs having an implementation cost of less than that of a procedure change, or $50,000, are unlikely. As a result of this review, PSEG identified three additional Phase I SAMAs to reduce seismic risk (PSEG 2009). The NRC staff concludes that the opportunity for seismic-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, seismic-related SAMA candidates.

As stated earlier, other external hazards (high winds, external floods, transportation and nearby facility accidents, release of on-site chemicals, and detritus) are below the IPEEE threshold screening frequency, or met the 1975 SRP design criteria, and are not expected to represent vulnerabilities. Nevertheless, PSEG reviewed the IPEEE results and subsequent plant changes for each of these external hazards and determined that either 1) the maximum benefit from eliminating all associated risk was less than approximately $50,000, which is the approximate value of implementing a procedure change at a single unit at SGS, or 2) only hardware enhancements that would significantly exceed the maximum value of any potential risk reduction were available. As a result of this review, PSEG identified no additional Phase I

SAMAs to reduce HFO risk (PSEG 2009). The NRC staff concludes that the licensee's rationale for eliminating other external hazards enhancements from further consideration is reasonable.

The NRC staff noted that, while the generic SAMA list from NEI 05-01 (NEI 2005) was stated to have been used in the identification of SAMAs for SGS, it was not specifically reviewed to identify SAMAs that might be applicable to SGS but rather was used to identify SAMAs that might address areas of concern identified in the SGS PRA (NRC 2010a). The NRC staff asked PSEG to provide further information to justify that this approach produced a comprehensive set of SAMAs for consideration. In response to the RAI, PSEG explained that, based on the early SAMA reviews, both the industry and NRC came to realize that a review of the generic SAMA list was of limited benefit because they were consistently found to not be cost-beneficial and that the real benefit was considered to be in the development of SAMAs generated based on plant specific risk insights from the PRA models (PSEG 2010a).

Furthermore, while the generic list does include potential plant improvements for plants having a similar design to SGS, plant designs are sufficiently different that the specific plant improvements identified in the generic list are generally not directly applicable to SGS, and require alteration to specifically address the SGS design and risk contributors or otherwise would be screened as not applicable to the SGS design. The NRC staff considers PSEG initial use of the NEI 05-01 generic SAMA list as only an idea source to generate SAMAs that address important contributors to SGS risk reasonable for the SGC application.

The NRC staff questioned PSEG about potentially lower cost alternatives to some of the SAMAs evaluated (NRC 2010a), including:

- Operating the AFW AF11/21 valves closed.
- Install improved fire barriers in the 460V switchgear rooms to provide separation between the three power divisions.
- Install improved fire barriers to provide separation between the AFW pumps.

In response to the RAIs, PSEG addressed the suggested lower cost alternatives and determined that they were either not feasible or were not cost-beneficial (PSEG 2010a). This is discussed further in Section F.6.2.

The NRC staff notes that the set of SAMAs submitted is not all-inclusive, since additional, possibly even less expensive, design alternatives can always be postulated. However, the NRC staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

The NRC staff concludes that PSEG used a systematic and comprehensive process for identifying potential plant improvements for SGS, and that the set of potential plant improvements identified by PSEG is reasonably comprehensive and, therefore, acceptable. This search included reviewing insights from the plant-specific risk studies, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events in the SAMA identification process was limited, it is recognized that the prior implementation of plant modifications for fire and seismic risks and the absence of external event vulnerabilities reasonably justifies examining primarily the internal events risk results for this purpose.

F.4 Risk Reduction Potential of Plant Improvements

PSEG evaluated the risk-reduction potential of the 25 remaining SAMAs and one sensitivity case SAMA that were applicable to SGS. The SAMA evaluations were performed using realistic assumptions with some conservatism. On balance, such calculations overestimate the benefit and are conservative.

PSEG used model re-quantification to determine the potential benefits. The CDF, population dose reductions, and offsite economic cost reductions were estimated using the SGS PRA model. The changes made to the model to quantify the impact of SAMAs are detailed in Section E.6 of Appendix E to the ER (PSEG 2009). Table F-6 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table F-6 reflect the combined benefit in both internal and external events. The determination of the benefits for the various SAMAs is further discussed in Section F.6.

The NRC staff questioned the assumptions used in evaluating the benefit or risk reduction estimate of SAMA 24, “provide procedural guidance to cross-tie Salem 1 and 2 service water systems” (NRC 2010a). The ER assumed this SAMA did not benefit from a reduction in fire risk yet indicates that this SAMA was identified based on a review of the SGS IPEEE fire PRA model results. In response to an NRC staff RAI, PSEG clarified that this SAMA was actually identified from the review of the internal events importance list, that the procedural guidance suggested in this SAMA to perform the inter-unit service water cross-tie is already in place for fire events and that, therefore, implementation of this SAMA would have no additional benefits in fire events (PSEG 2010a). Based on this, PSEG concluded that this SAMA has been appropriately evaluated, with which the NRC staff agrees.

The NRC staff noted that the total of the risk reduction results calculated by summing the individual results for each release category for SAMAs 2, 4, 5A, 18, and 19 was different than the summary results that were used in the SAMA evaluation (NRC 2010a). In response to the RAI, PSEG explained that the release category results provided in the ER for these SAMAs were incorrect, due to typographical errors, and the correct results were provided (PSEG 2010a). PSEG further explained that the SAMA evaluation reported in the ER used the correct release category results and therefore no re-evaluation of the SAMAs was necessary. The NRC staff accepts PSEG's explanation based upon the staff's confirmation that the revised information is aligned with that reported in the ER.

For SAMAs that specifically addressed fire events (i.e., SAMA 21, "Seal the Category II and III Cabinets in the Relay Room," SAMA 22, "Install Fire Barriers between the 1CC1, 1CC2, and 1CC3 Consoles in the Control Room Enclosure (CRE)," and SAMA 23, "Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room."), the reduction in fire CDF and population dose was not directly calculated (in Table F-5 this is noted as "Not Estimated"). For these SAMAs, an estimate of the impact was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to fire events; the fraction of the fire risk affected by the SAMA (based on information from the IPEEE and interim SGS Fire Model results); and the assumption that SAMAs 21 and 22 completely eliminate the fire risk affected by the SAMA and that SAMA 23 eliminates 95 percent of the fire risk affected by the SAMA. Specifically, it is assumed that the contribution to risk from external events is approximately equal to that from internal events, and that internal fires contribute 72 percent of this external events risk. The fire areas impacted by the SAMA are identified and the portion of the total fire risk contributed by each of these fire areas determined. For SAMAs 21 and 22, the benefit or averted cost risk from reducing the fire risk affected by the SAMA is then calculated by multiplying the ratio of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS. For SAMA 23, the benefit or averted cost risk from reducing the fire risk affected by the SAMA is then calculated by multiplying the ratio of 95 percent of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS. These SAMAs were assumed to have no additional benefits for internal events.

In addition to those SAMAs that only addressed fire events, PSEG evaluated the additional benefits from reducing fire risk for the following SAMAs that also had internal events benefits: SAMA 1, "Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation," SAMA 8, "Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header," and SAMA 20, "Fire Protection System to Provide Make-up to RCS and Steam Generators." The benefit or averted cost risk from reducing the fire risk affected by these SAMAs was calculated similar to the method described above with the exception that the fire risk affected by each of these SAMAs were assumed to be reduced based on the same failure probability as was assumed for internal events (i.e., 2.0×10^{-02} for SAMA 1, 1.0×10^{-02} for SAMA 8, and 1.0×10^{-01} for SAMA 20). In other words, SAMA 1 was assumed to eliminate 98 percent, SAMA 8 was assumed to eliminate 99 percent, and SAMA 20 was assumed to eliminate 90 percent of the fire risk affected by these SAMAs. The benefit or averted cost risk from reducing the fire risk affected by SAMA 1 is then calculated by multiplying the ratio of 98 percent of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS. The benefit from reducing fire risk was calculated similarly for SAMAs 8 and 20. For SAMAs 1 and 8, PSEG added the calculated benefit from reducing fire risk to the benefit from internal events, which was doubled to account for all external events, to obtain the total benefit from internal and external events. This is discussed further in Section F.6.2.

PSEG also evaluated the additional benefits from reducing seismic risk for the following SAMAs that also had internal events benefits: SAMA 5, “Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation,” SAMA 5A, “Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries,” SAMA 20, “Fire Protection System to Provide Make-up to RCS and Steam Generators,” and SAMA 27, “In addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources.” For these SAMAs, an estimate of the seismic impact was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to seismic events; the fraction of the seismic risk affected by the SAMA (based on information from the IPEEE); and the assumption that these SAMAs would reduce the contribution to the seismic CDF from the impacted seismic sequences by 90 percent. Specifically, it is assumed that the contribution to risk from external events is approximately equal to that from internal events, and that seismic events contribute 18 percent of this external events risk. The seismic sequences impacted by the SAMA are identified and the portion of the total seismic risk contributed by each of these seismic sequences determined. The benefit or averted cost risk from reducing the seismic risk affected by the SAMA is then calculated by multiplying the ratio of 90 percent of the seismic risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS. For SAMAs 5, 5A, and 27, PSEG added the calculated benefit from reducing seismic risk to the benefit from internal events, which was doubled to account for all external events, to obtain the total benefit from internal and external events. This is discussed further in Section F.6.2.

For SAMA 20, PSEG multiplied the benefit from internal events by a factor of 1.1 to account for other (non-fire/non-seismic) events and added this to the benefits or averted cost risk from reducing fire risk and seismic risk to obtain the total benefit from internal and external events. This is discussed further in Section F.6.2.

The NRC staff has reviewed PSEG's bases for calculating the risk reduction for the various plant improvements and concludes, with the above clarifications, that the rationale and assumptions for estimating risk reduction are reasonable and generally conservative (i.e., the estimated risk reduction is higher than what would actually be realized). Accordingly, the NRC staff based its estimates of averted risk for the various SAMAs on PSEG's risk reduction estimates.

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
1 – Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation	Modify fault tree to include a new HEP event, having a failure probability of 2.0E-02, representing failure of the operator to open doors and align fans. In addition, reduce the fire CDF contribution from fires in Fire Area 1FA-EP-100G/1F1-PP-100H assuming the same failure probability.	34	30	4.8M	12M	475K
2 – Re-configure SGS 3 to Provide a More Expedient Backup AC Power Source for SGS 1 and 2	SGS 3 (gas turbine) credited for weather-related and switchyard LOOPs.	10	10	1.6M	4.0M	875K
3 – Install Limited EDG Cross-Tie Capability Between SGS 1 and 2	Modify fault tree to include a new basic event, having a failure probability of 5.0E-02, representing failure to cross-tie.	16	15	2.4M	6.0M	4.2M
4 – Install Fuel Oil Transfer Pump on "C" EDG & Provide Procedural Guidance for Using "C" EDG to Power Selected "A" and "B" Loads	Modify fault tree to include a new basic event, having a failure probability of 1.0E-02, representing failure of all three fuel oil transfer pumps. Also modify fault tree to cross-tie Train A, B, and C engineered safety feature (ESF) buses.	16	15	2.4M	6.0M	585K

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
5 – Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries and Replace PDP with Air-Cooled Pump	**Modify fault tree to include a new basic event, having a failure probability of 1.0E-01, representing hardware and operator failure of new charging pump. Also, as provided in response to an NRC staff RAI, likelihood of offsite power nonrecovery changed to 1.0E-02 from 2.4E-01 for grid and from 1.0E-01 for site/switchyard-related causes and to 3.0E-02 from 2.4E-01 for weather-related causes.**	**16**	**11**	**3.1M**	**7.6M**	**3.3M**
5A[b] – Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries	**As provided in response to an NRC staff RAI, likelihood of offsite power nonrecovery changed to 1.0E-02 from 2.4E-01 for grid and from 1.0E-01 for site/switchyard-related causes and to 3.0E-02 from 2.4E-01 for weather-related causes.**	**10**	**10**	**2.4M**	**6.0M[d]**	**770K**
6 – Enhance Flood Detection for 84' Auxiliary Building and Enhance Procedural Guidance for Responding to Service Water Flooding	**The failure probabilities of existing operator actions to detect and isolate floods successfully were multiplied by a factor of 0.1.**	**6**	**1**	**300K**	**750K**	**250K**
7 – Install "B" Train Auxiliary Feedwater Storage Tank (AFWST) Makeup Including Alternate Water Source	**Modify fault tree to include a new basic event, having a failure probability of 1.0E-03, representing failure of the alternate water source.**	**7**	**1**	**410K**	**1.0M**	**470K**

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
8 – Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header	**Modify fault tree to include a new basic event, having a failure probability of 1.0E-02, representing failure of the new pump. In addition, reduce the fire CDF contribution from fires in Fire Areas 12FA-SB-100/1FA-TGA-88 and 1FA-AB-84B assuming the same failure probability.**	**15**	**6**	**1.6M**	**4.1M**	**2.5M**
9 – Connect Hope Creek Cooling Tower Basin to SGS Service Water System as Alternate Service Water Supply	**Reduce failure probabilities for all service water fouling events by a factor of 10.**	**13**	**11**	**1.7M**	**4.3M**	**1.2M**
10 – Provide Procedural Guidance for Faster Cooldown Loss of RCP Seal Cooling	**The probability that operators would fail to reduce reactor coolant system (RCS) pressure was reduced to 0.1 from 1.0.**	**1**	**<1**	**110K**	**280K**	**100K**
11 – Modify Plant Procedures to Make use of Other Unit's PDP for RCP Seal Cooling	**The probability that operators would fail to respond short/long-term seal injection demand was reduced to 0.1 from 1.0.**	**13**	**12**	**2.0M**	**5.0M**	**100K**
12 – Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms	**Reduce likelihood that the drains would fail to remove the volume of water assumed in the flooding analysis from 1.0E-01 to 1.0E-03.**	**3**	**3**	**550K**	**1.4M**	**475K**
13 – Install Primary Side Isolation Valves on the Steam Generators	Reduce likelihood of a SGTR in each steam generator from 1.75E-03 to 1.75E-05.	6	30	5.2M	13M	18M

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
14 – Expand AMSAC Function to Include Backup Breaker Trip on Reactor Protection System (RPS) Failure	**Modify fault tree to AND the current event for electrical RPS trip failure with the top gate for AMSAC.**	**19**	**<1**	**530K**	**1.3M**	**485K**
15 – Automate RCP Seal Injection Realignment upon Loss of Component Cooling Water (CCW)	Reduce likelihood of failure to isolate letdown and realign suction source to the refueling water storage tank (RWST) from 1.0E-02 to 1.0E-03.	1	<1	42K	69K	210K
16 – Install Additional Train of Switchgear Room Cooling	Reduce likelihood of operator failure to open doors and establish alternate switchgear room cooling from 5.90E-03 to 5.90E-05.	1	1	180K	450K	2.5M
17 – Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation	**As provided in response to an NRC staff RAI, reduce likelihood of failure of EDG control room HVAC fans from 4.80E-03 to 4.8E-04 for two fans and 2.3E-06 for the third fan.**	**3**	**3**	**510K**	**1.3M**	**200K**
18 – Redundant Service Water (SW) Turbine Header Isolation Valve	Reduce failure probability for the operator action to close the SW turbine header valves from 2.20E-02 to 1.0E-03.	<1	<1	140K	350K	635K
19 – Install Spray Shields on Residual Heat Removal (RHR) Pumps	Reduce initiating event frequency for the 45' elevation Auxiliary Building spray scenario from 7.60E-04 to 7.60E-06.	1	0	34K	84K	350K

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
20 – Fire Protection System to Provide Make-up to RCS and Steam Generators (SGs)	Modify fault tree to include two new basic events, having failure probabilities of 1.0E-02 and 1.0E-01, representing failure of the new AFW pump and independently-powered charging pump, respectively. In addition, reduce the fire CDF contribution from fires in Fire Areas 1FA-AB-84A, 1FA-EP-78C, 1FA-AB-64A, 1FA-AB-84B, and 12FA-SB-100/1FA-TGA-88 assuming the same failure probability of 1.0E-01.	21	7	5.1M	12.7M	13M
21 – Seal the Category II and III Cabinets in the Relay Room	Eliminate the fire CDF contribution from fire damage state 1RE2.	NOT ESTIMATED		870K	2.2M	3.2M
22 – Install Fire Barriers between the 1CC1, 1CC2, and 1CC3 Consoles in the CRE	Eliminate the fire CDF contribution from Fire Damage State CR16.	NOT ESTIMATED		330K	830K	1.6M
23 – Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room	Reduce the fire CDF contribution from transient combustible fires in Fire Area 1FA-AB-64A, 4160 Switchgear Room, by 95 percent.	NOT ESTIMATED		300K	750K	975K
24 – Provide Procedural Guidance to Cross-tie SGS 1 and 2 Service Water Systems	**Modify fault tree to prevent a complete loss of service water event for events which can affect service water supply to one unit only.**	**9**	**4**	**700K**	**1.8M**	**175K**

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
27 – In addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources	**Modify fault tree to include a new basic event, having a failure probability of 1.0E-01, representing hardware and operator failure of new charging pump. Also, as provided in response to an NRC staff RAI, likelihood of offsite power nonrecovery changed to 1.0E-02 from 2.4E-01 for grid and from 1.0E-01 for site/switchyard-related causes and to 3.0E-02 from 2.4E-01 for weather-related causes.**	**16**	**11**	**3.1M**	**7.7M**	**4.2M**
30[c] – Automatic Start of Diesel-Powered Air Compressor	The failure probability for the operator action to start the diesel-powered air compressor was reduced by a factor of 100 to 6.3E-04 from 6.3E-02.	1	<1	40K	83K	100K
31[c] – Fully Automate Swapover to Sump Recirculation	The failure probability for the operator action to swapover to sump recirculation was reduced by a factor of 100 to 5.3E-05 from 5.3E-03.	1	<1	27K	56K	100K
32[c] – Enhance Flood Detection for 100-foot Auxiliary Building and Enhance Procedural Guidance for Responding to Internal Floods	The failure probability for the operator action to isolate the flood source was reduced by a factor of 100 to 1.0E-03 from 1.0E-01.	1	<1	50K	100K	250K

Table F-6. SAMA Cost/Benefit Screening Analysis for SGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	

(a) SAMAs in bold are potentially cost-beneficial.

(b) SAMA 5A added as a sensitivity case to SAMA 5 to provide a comprehensive, long term mitigation strategy for SBO scenarios.

(c) SAMAs 30, 31, and 32 were identified and evaluated in response to an NRC staff RAI (PSEG 2010a). The RAI response stated that the percent risk reduction was developed using SGS PRA Model Version 4.3 and that the implementation costs for SAMAs 30 and 31 are expected to be significantly greater than the $100K assumed in the SAMA evaluation.

(d) Value estimated by NRC staff using information provided in the ER.

(e) Using a factor of 2.5.

F.5 Cost Impacts of Candidate Plant Improvements

PSEG estimated the costs of implementing the 25 candidate SAMAs through the development of site-specific cost estimates. The cost estimates conservatively did not include the cost of replacement power during extended outages required to implement the modifications (PSEG 2009).

The NRC staff reviewed the bases for the applicant's cost estimates (presented in Table E.5-3 of Attachment E to the ER). For certain improvements, the NRC staff also compared the cost estimates to estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees' analyses of SAMAs for operating reactors.

The ER stated that plant personnel developed SGS-specific costs to implement each of the SAMAs. The NRC staff requested more information on the process PSEG used to develop the SAMA cost estimates (NRC 2010a). PSEG responded to the RAI by explaining that the cost estimates were developed in a series of meetings involving personnel responsible for development of the SAMA analysis and the two PSEG license renewal site leads who are engineering managers each having over 25 years of plant experience, including project management, operations, plant engineering, design engineering, procedure support, simulators, and training (PSEG 2010a). During these meetings, each SAMA was validated against the plant configuration, a budget-level estimate of its implementation cost was developed, and, in some instances, lower cost approaches that would achieve the same objective were developed. The SAMA implementation costs were then reviewed by the Design Engineering Manager for both technical and cost perspectives and revised accordingly. PSEG further explained that seven general cost categories were used in development of the budget-level cost estimates: engineering, material, installation, licensing, critical path impact, simulator modification, and procedures and training. For costs that could be shared between the two SGS units, the total estimated cost was evenly divided between the two units to develop a per unit cost. Based on the use of personnel having significant nuclear plant engineering and operating experience, the NRC staff considers the process PSEG used to develop budget-level cost estimates reasonable.

In response to an RAI requesting a more detailed description of the changes associated with SAMAs 3, 5, 8, 13, 20, and 23, PSEG provided additional information detailing the analysis and plant modifications included in the cost estimate of each improvement (PSEG 2010a). The staff reviewed the costs and found them to be reasonable, and generally consistent with estimates provided in support of other plants' analyses.

The NRC staff also noted that the ER reported an implementation cost for SAMA 3, "Install Limited EDG Cross-Tie Capability Between SGS 1 and 2," of $4.175M in Section E.6.3 and $525K in Section E.5-3 and requested clarification on which was the correct value (NRC

2010a). SEG responded that $4.175K was the correct value and stated that this value was used in the SAMA evaluation (PSEG 2010a).

The NRC staff requested PSEG provide justification for the differences in the cost estimates for SAMA 1, “Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation,” having a cost of $475K, and SAMA 17, “Enhance Procedures and Provide Additional Equipment to Respond to Loss of Emergency Diesel Generator (EDG) Control Room Ventilation,” having a cost of $200K, which are similar in that each involves opening doors to provide ventilation and using portable fans to enhance natural circulation (NRC 2010a). In response to the RAI, PSEG stated that SAMA 1 has a higher cost because it is a more complicated modification involving three rooms having differing requirements while SAMA 17 involves four rooms that are basically identical (PSEG 2010a). The NRC staff considers the basis for the differences in cost estimates reasonable.

The NRC staff noted that SAMA 21, “Seal the Category II and III Cabinets in the Relay Room,” and SAMA 22, “Install Fire Barriers between the 1CC1, 1CC2, and 1CC3 Consoles in the CRE,” are similar in that each involves installing fire barriers to prevent the propagation of a fire between cabinets and requested an explanation for why the estimated cost of $3.23M for SAMA 21 to modify 48 cabinets is similar to the estimated cost of $1.6M for SAMA 22 to modify just three consoles (NRC 2010a). PSEG responded that the cost per console ($400K) in SAMA 22, is much higher than the cost per cabinet ($35K - $70K) in SAMA 21 because making the modifications to the Control Room consoles is more complicated than making the modifications to the Relay Room cabinets (PSEG 2010a). Specifically, SAMA 22 requires making ventilation modifications due to the significant heat loads in addition to adding fire barrier materials. The NRC staff considers the basis for the differences in cost estimates reasonable.

The NRC asked PSEG to justify the estimated cost of $100K for SAMA 10, “Provide Procedural Guidance for Faster Cooldown Loss of RCP Seal Cooling,” and SAMA 11, “Modify Plant Procedures to Make use of Other Unit’s Positive Displacement Pump (PDP) for RCP Seal Cooling,” in light of the statement made in the ER that the minimum expected implementation cost is assumed to be a procedure change at $50K per site, based on a cost of $100K for the site (NRC 2010a). In response to the RAI, PSEG explained that the cost for SAMA 10 includes 1) $50K to perform a feasibility study to confirm that there is no technical basis preventing implementation of a more rapid cooldown on loss of RCP seal cooling and 2) $150K to revise the emergency operating procedures (EOPs), which are more expensive to revise and require more extensive training than other plant procedures (PSEG 2010a). PSEG also explained that the cost for SAMA 11 includes 1) $50K to perform a feasibility study to confirm that there is no technical basis preventing PDP cross-tie when RCP seal cooling is lost, 2) $50K to revise the plant procedures, and 3) $50K for each unit to involve plant licensing staff. The total of $200K for both SAMAs is divided evenly between the two units. The NRC staff considers the bases for the estimated costs for these SAMAs reasonable.

The NRC staff concludes that the cost estimates provided by PSEG are sufficient and appropriate for use in the SAMA evaluation.

F.6 Cost-Benefit Comparison

PSEG's cost-benefit analysis and the NRC staff's review are described in the following sections.

F.6.1 PSEG's Evaluation

The methodology used by PSEG was based primarily on NRC's guidance for performing cost-benefit analysis, i.e., NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997a). The guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where
APE = present value of averted public exposure ($)
AOC = present value of averted offsite property damage costs ($)
AOE = present value of averted occupational exposure costs ($)
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($)

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. PSEG's derivation of each of the associated costs is summarized below.

NUREG/BR-0058 has recently been revised to reflect the agency's policy on discount rates. Revision 4 of NUREG/BR-0058 states that two sets of estimates should be developed, one at 3 percent and one at 7 percent (NRC 2004). PSEG provided a base set of results using the 3 percent discount rate and a sensitivity study using the 7 percent discount rate (PSEG 2009).

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δperson-rem/year)

× monetary equivalent of unit dose ($2,000 per person-rem)
× present value conversion factor (15.04 based on a 20-year period with a 3-percent discount rate)

As stated in NUREG/BR-0184 (NRC 1997a), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents, PSEG calculated an APE of approximately $2,350,000 for the 20-year license renewal period (PSEG 2009).

Averted Offsite Property Damage Costs (AOC)

The AOCs were calculated using the following formula:

AOC = Annual CDF reduction
x offsite economic costs associated with a severe accident (on a per-event basis)
x present value conversion factor.

This term represents the sum of the frequency-weighted offsite economic costs for each release category, as obtained for the Level 3 risk analysis. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOC of about $306,000 based on the Level 3 risk analysis. This results in a discounted value of approximately $4,600,000 for the 20-year license renewal period.

Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated using the following formula:

AOE = Annual CDF reduction
× occupational exposure per core damage event
× monetary equivalent of unit dose
× present value conversion factor

PSEG derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997a). Best estimate values provided for immediate occupational dose (3,300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-year cleanup period) were used. The present value of these doses was calculated using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of $2,000 per person-rem, a real discount rate of 3 percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOE of approximately $31,000 for the 20-year license renewal period (PSEG 2009).

Averted Onsite Costs

Averted onsite costs (AOSC) include averted cleanup and decontamination costs and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. PSEG derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR-0184, the regulatory analysis handbook (NRC 1997a).

PSEG divided this cost element into two parts – the onsite cleanup and decontamination cost, also commonly referred to as averted cleanup and decontamination costs (ACC), and the replacement power cost (RPC).

ACCs were calculated using the following formula:

ACC = Annual CDF reduction
x present value of cleanup costs per core damage event
× present value conversion factor

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR-0184 to be $\$1.5 \times 10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an ACC of approximately $965,000 for the 20-year license renewal period.

Long-term RPCs were calculated using the following formula:

RPC = Annual CDF reduction
x present value of replacement power for a single event
× factor to account for remaining service years for which replacement power is required
× reactor power scaling factor

PSEG based its calculations on a SGS net output of 1115 megawatt electric (MWe) and scaled up from the 910 MWe reference plant in NUREG/BR-0184 (NRC 1997a). Therefore PSEG applied a power scaling factor of 1115/910 to determine the replacement power costs. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an RPC of approximately $335,000 and an AOSC of approximately $1,300,000 for the 20-year license renewal period.

Using the above equations, PSEG estimated the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS to be about $8.28M. Use of a multiplier of 2 to account for external events increases the value to $16.56M and represents the dollar value associated with completely eliminating all internal and external event severe accident risk for a single unit at SGS, also referred to as the Single Unit Maximum Averted Cost Risk (MACR).

PSEG's Results

If the implementation costs for a candidate SAMA exceeded the calculated benefit, the SAMA was considered not to be cost-beneficial. In the baseline analysis contained in the ER (using a 3 percent discount rate and considering the impact of external events), PSEG identified 11 potentially cost-beneficial SAMAs. PSEG performed additional analyses to evaluate the impact of parameter choices (alternative discount rates and variations in MACCS2 input parameters) and uncertainties on the results of the SAMA assessment and, as a result of this analysis, identified five additional potentially cost-beneficial SAMAs. PSEG also performed an analysis on a less costly alternative to SAMA 5 (SAMA 5A) and found it to be potentially cost-beneficial.

The potentially cost-beneficial SAMAs for SGS are the following:

- SAMA 1 – Enhance Procedures and Provide Additional Equipment to Respond to Loss of Control Area Ventilation
- SAMA 2 – Re-configure Salem 3 to Provide a More Expedient Backup AC Power Source for Salem 1 and 2
- SAMA 3 – Install Limited EDG Cross-tie Capability Between Salem 1 and 2
- SAMA 4 – Install Fuel Oil Transfer Pump on "C" EDG & Provide Procedural Guidance for Using "C" EDG to Power Selected "A" and "B" Loads
- SAMA 5 – Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries & Replace PDP with Air-Cooled Pump
- SAMA 5A – Install Portable Diesel Generators to Charge Station Battery and Circulating Water Batteries
- SAMA 6 – Enhance Flood Detection for 84' Aux Building and Enhance Procedural Guidance for Responding to Service Water Flooding
- SAMA 7 – Install "B" Train AFWST Makeup Including Alternate Water Source

- SAMA 8 – Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header
- SAMA 9 – Connect Hope Creek Cooling Tower Basin to Salem Service Water System as Alternate Service Water Supply
- SAMA 10 – Provide Procedural Guidance for Faster Cooldown on Loss of RCP Seal Cooling
- SAMA 11 – Modify Plant Procedures to Make Use of Other Unit's PDP for RCP Seal Cooling
- SAMA 12 – Improve Flood Barriers Outside of 220/440VAC Switchgear Rooms
- SAMA 14 – Expand AMSAC Function to Include Backup Breaker Trip on RPS Failure
- SAMA 17 – Enhance Procedures and Provide Additional Equipment to Respond to Loss of EDG Control Room Ventilation
- SAMA 24 – Provide Procedural Guidance to Cross-tie Salem 1 and 2 Service Water Systems
- SAMA 27 –In Addition to the Equipment Installed for SAMA 5, Install Permanently Piped Seismically Qualified Connections to Alternate AFW Water Sources

PSEG indicated that they plan to further evaluate these SAMAs for possible implementation using existing action-tracking and design change processes (PSEG 2009).

The potentially cost-beneficial SAMAs, and PSEG's plans for further evaluation of these SAMAs, are discussed in detail in Section F.6.2.

F.6.2 Review of PSEG's Cost-Benefit Evaluation

The cost-benefit analysis performed by PSEG was based primarily on NUREG/BR-0184 (NRC 1997a) and discount rate guidelines in NUREG/BR-0058 (NRC 2004) and was executed consistent with this guidance.

SAMAs identified primarily on the basis of the internal events analysis could provide benefits in certain external events, in addition to their benefits in internal events. To account for the additional benefits in external events, PSEG multiplied the internal event benefits for all but one internal event SAMA (SAMA 20, discussed further below) by a factor of 2, which is approximately the ratio of the total CDF from internal and external events to the internal event

CDF (PSEG 2009). As discussed in Section F.2.2, this factor was based on a seismic CDF of 9.5×10^{-6} per year, plus a fire CDF of 3.8×10^{-5} per year, plus the screening values for high winds, external flooding, transportation, detritus, and chemical release events (1×10^{-6} per year for each). The external event CDF of 5.3×10^{-5} per year is thus about 110 percent of the internal events CDF used in the SAMA analysis (5.0×10^{-5} per year). The total CDF is 2.1 times the internal events CDF and this was rounded to 2. Eleven SAMAs were determined to be cost-beneficial in PSEG's analysis (SAMAs 1, 2, 4, 6, 9, 10, 11, 12, 14, 17, and 24 as described above).

PSEG did not multiply the internal event benefits by the factor of 2 for three SAMAs that specifically address fire risk (SAMAs 21, 22, and 23). Doubling the internal event estimate for SAMAs 21, 22, and 23 would not be appropriate because these SAMAs are specific to fire risks and would not have a corresponding benefit on the risk from internal events.

For all but one internal event SAMA also having benefits in fire and seismic risk (i.e., SAMAs 1, and 8 for fire and SAMAs 5, 5A, and 27 for seismic), PSEG separately quantified the benefits for fire and seismic events and added these results to the benefits from internal events and external events developed from applying the factor of 2 (as discussed in Section F.4 above). The NRC staff noted that this process appeared to be double counting the benefits from external events and requested clarification (NRC 2010a). In response to the RAI, PSEG acknowledged that this process results in "double counting" of some external event contributions to the total averted cost risk and stated that this approach was retained, unless it resulted in a gross misrepresentation of a SAMA's benefit, in order to avoid underestimating the external events averted cost risk (PSEG 2010a). PSEG further concluded that this process does not impact the conclusions of the SAMA analysis. Since the process that PSEG used over-estimates the benefits from external events and therefore results in conservative estimates of the SAMA benefits, the NRC staff considers the process PSEG used acceptable for the SAMA evaluation.

For SAMA 20, "Fire Protection System to Provide Make-up to RCS and Steam Generators," PSEG multiplied the estimated benefits for internal events by a factor of 2.0 to account for external events in the Phase I analysis. In the Phase II analysis, PSEG separately quantified the internal event, fire event, and seismic event benefits, as described in Section F.4 above, and to account for the additional benefits in other (non-fire/non-seismic) external events, PSEG multiplied the internal event benefits by a factor of 1.1, which is the ratio of the total CDF from internal and other external events to the internal event CDF (based on an HFO CDF of 5.0×10^{-6} per year and an internal events CDF of 5.0×10^{-5} per year used in the SAMA analysis). The estimated SAMA benefits for internal events with the factor of 1.1 applied to account for other external events, fire events, and seismic events were then summed to provide an overall benefit. Since the methodology PSEG used accounts for both internal events and external events, the NRC staff considers the methodology PSEG used for SAMA 20 acceptable for the SAMA evaluation.

PSEG considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. In the ER, PSEG presents the results of an uncertainty analysis of the internal events CDF which indicates that the 95th percentile value is a factor of 1.64 times the point estimate CDF for SGS. Since the one Phase I SAMA that was screened based on qualitative criteria was screened due to not being applicable to SGS, a re-examination of the Phase I SAMAs based on the upper bound benefits was not necessary. PSEG considered the impact on the Phase II screening if the estimated benefits were increased by a factor of 1.64 (in addition to the multiplier of 2 for external events). Four additional SAMAs became cost-beneficial in PSEG's analysis (SAMAs 5, 7, 8, and 27 as described above).

PSEG noted that the 95th percentile value for CDF may be underestimated because uncertainty distributions are not applied to all basic events in the SGS PRA model. Based on this, PSEG used a factor of 2.5 times the point estimate CDF to represent the 95th percentile value, which is stated to be typical of most light water reactor CDF uncertainty analyses. PSEG considered the impact on the Phase II screening if the estimated benefits were increased by a factor of 2.5 (in addition to the multiplier of 2 for external events). One additional SAMA became cost-beneficial (SAMA 3). The NRC staff notes that while the factor of 2.5 does not represent an upper bound, it is typical of factors used in prior SAMA analyses, is higher than the factor calculated for other Westinghouse 4-loop plants and used in prior SAMA analysis, and is therefore considered by the NRC staff to be appropriate for use in the SAMA sensitivity analyses.

PSEG provided the results of additional sensitivity analyses in the ER, including use of a 7 percent discount rate and variations in MACCS2 input parameters. These analyses did not identify any additional potentially cost-beneficial SAMAs (PSEG 2009).

The NRC staff noted that the ER reported that the licensed thermal power for SGS Unit 1 is 3,459 MWt, which equates to a net electrical output of 1,195 MWe when operating at 100 percent power, while 1,115 MWe was used to calculate long-term replacement power costs for the SAMA analysis (NRC 2010a). In response to the RAI, PSEG clarified that 1,115 MWe used in the SAMA analysis was incorrect and provided a revised replacement power cost estimate of $359,000 using the correct 1,195 MWe, which is an approximately 7 percent increase over that used in the SAMA analysis (PSEG 2010a). PSEG also provided a revised MACR of $16.61M, which is an increase of about 0.3 percent over the MACR used in the SAMA analysis and concluded that the small error would have a negligible impact on the conclusions of the SAMA analysis. The NRC staff agrees with this assessment.

As indicated in Section F.3.2, in response to an NRC staff RAI, PSEG extended the review of Level 1 and Level 2 basic events down to an RRW of 1.006, which equates to a benefit of about $47,000, using SGS PRA MOR Revision 4.3 (PSEG 2010a). The review identified the following three additional SAMAs associated with new basic events added to the importance lists: 1) SAMA 30, "Automatic Start of Diesel-Powered Air Compressor," 2) SAMA 31, "Fully Automate

Swapover to Sump Recirculation," and 3) SAMA 32, "Enhance Flood Detection for 100-foot Auxiliary Building and Enhance Procedural Guidance for Responding to Internal Floods." Each of these new SAMAs is included in Table F-6. PSEG performed a Phase II evaluation using results for SGS PRA MOR Revision 4.3 and the process described above. PSEG stated that the release frequency for MOR Revision 4.3 is 2.2×10^{-5} per year, a decrease of over 50 percent from MOR Revision 4.1, and that the 95th percentile value for CDF is a factor of 2.1 times the point estimate CDF. Based on information provided in the RAI response, the NRC staff estimated, for the MOR Revision 4.3 results, the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at SGS to be about $2.3M, a revised external event multiplier of about 3.4, and a revised MACR of about $7.9M. These results represent a decrease of more than 50 percent compared to the SGS PRA MOR 4.1 results reported in the ER. PSEG's analysis determined that none of the three SAMA candidates was cost-beneficial in either the baseline analysis or the uncertainty analysis.

Based on these results for MOR Revision 4.3 and the changes in the importance lists, the NRC staff asked PSEG to assess the impact on the SAMA evaluation of the PRA model changes made since MOR Revision 4.1 (NRC 2010b). In response to the RAI, PSEG re-evaluated each potentially cost-beneficial SAMA using MOR Revision 4.3 and determined that SAMA benefits both increased (up to 42 percent) and decreased (up to 99 percent) from the results using MOR Revision 4.1 and that five SAMA candidates (SAMA 3, 5, 11, 14, and 27) would no longer be cost-beneficial (PSEG 2010b). PSEG also qualitatively evaluated each SAMA determined to not be cost-beneficial and concluded that none would become cost-beneficial using MOR Revision 4.3 based on the following:

- The implementation cost is greater than the revised MACR even after accounting for uncertainty (SAMA 13).
- For SAMAs that address fire events only, the maximum averted cost risk for external events decreased, which would result in a corresponding decrease in the maximum calculated benefit for these SAMAs (SAMAs 21, 22, and 23).
- The cost of implementation was sufficiently greater than the MOR Revision 4.1 benefit that changes in MOR Revision 4.3 would not be expected to overcome the difference (SAMAs 15, 16, 18, and 19). The NRC staff notes that this difference, even after accounting for uncertainty, is on the order of 50 percent or more for all of these SAMAs and agrees that it is unlikely that a revised evaluation would result in a change to the cost-beneficial status for these SAMAs.
- The cost of implementation is greater than the revised MACR (SAMA 20). The NRC staff notes that MOR Revision 4.1 results indicate that the fire and seismic events contributors to the MACR are four times the internal events contribution and, since the maximum averted cost risk for external events has decreased with MOR Revision 4.3,

agrees that it is unlikely that a revised evaluation would result in a change to cost-beneficial status for this SAMA.

As indicated in Section F.3.2, the NRC staff asked the licensee to evaluate several potentially lower cost alternatives to the SAMAs considered in the ER (NRC 2010a), as summarized below:

- Operating the AFW AF11/21 valves closed in lieu of SAMA 8, “Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header.” In response to the RAI, PSEG stated that the AF11 valves on the discharge side of the motor-driven AFW pumps are already operated closed, leaving only the AF21 valves on the discharge side of the turbine-driven AFW pump operating open (PSEG 2010a). Steam binding of the common suction line to all three AFW pumps could therefore only occur as a result of high temperature water leaks through three check valves in series on the discharge to the turbine-driven AFW pump. PSEG concluded that the proposed improvement would not be feasible because 1) industry data used to represent common-cause steam binding of all three AFW pumps appears to be conservative relative to the SGS configuration, thereby overstating the risk significance of this failure at SGS, 2) operating all of the AF11/21 valves closed could actually provide a negative risk benefit based on a new failure event to represent common-cause failure of the valves to open, and 3) operating all of the AF11/21 valves closed could have a potentially adverse effect on the SGS design basis because design-basis calculations and assumptions would need to be modified to reflect this change in AFW strategy.

- Install improved fire barriers in the 460V switchgear rooms to provide separation between the three power divisions in lieu of SAMA 20, “Fire Protection System to Provide Make-up to RCS and Steam Generators.” In response to the RAI, PSEG explained that the configuration of Fire Area 1FA-AB-84A, addressed by SAMA 20, is significantly more complex than Fire Area 1FA-AB-64A, addressed by SAMA 23, “Install Fire Barriers and Cable Wrap to Maintain Divisional Separation in the 4160V AC Switchgear Room” (PSEG 2010a). The SAMA 23 estimated implementation cost of $975K only addresses the risk associated with preventing the spread of transient fires between divisions and did not address the entire fire risk in the fire area, which would include protecting the overhead cables. PSEG estimates that the cost of addressing the entire fire risk in Fire Area 1FA-AB-64A would be at least an order of magnitude greater than the estimated implementation cost for SAMA 23. PSEG further estimates that the cost of addressing the fire risk in Fire Area 1FA-AB-84A could be double that for Fire Area 1FA-AB-64A. The maximum benefit of the proposed SAMA, which assumes elimination of all fire risk for Fire Area 1FA-AB-84A, is estimated to be $2.0M in the baseline analysis, or $5.1M accounting for uncertainties, using the MOR Rev. 4.1 PRA model. Furthermore, PSEG determined that the maximum benefit would be about 30 percent lower if the MOR Rev. 4.3 PRA model were used. Because the estimated implementation cost is significantly greater than the maximum potential benefit, PSEG concluded that the proposed SAMA would not be cost-beneficial.

- Install improved fire barriers to provide separation between the AFW pumps in lieu of SAMA 8, "Install High Pressure Pump Powered with Portable Diesel Generator and Long-term Suction Source to Supply the AFW Header." In response to the RAI, PSEG estimated the cost to implement the proposed SAMA to be $750K (PSEG 2010a). Failure of multiple AFW pumps accounted for about 67 percent of the Fire Area 1FA-AB-84B fire risk. The maximum benefit of the proposed SAMA, which assumes elimination of all of this fire risk, is estimated to be $120K in the baseline analysis, or $290K accounting for uncertainties, using the MOR Rev. 4.1 PRA model. Furthermore, PSEG determined that the maximum benefit would be about 30 percent lower if the MOR Rev. 4.3 PRA model were used. Because the estimated implementation cost is significantly greater than the maximum potential benefit, PSEG concluded that the proposed SAMA would not be cost-beneficial.

PSEG indicated that the 17 potentially cost-beneficial SAMAs (SAMAs 1, 2, 3, 4, 5, 5A, 6, 7, 8, 9, 10, 11, 12, 14, 17, 24, and 27) will be considered for implementation through the established Salem Plant Health Committee (PHC) process (PSEG 2009). In response to an NRC staff RAI, PSEG described the PHC as being chaired by the Plant Manager and includes as members the Plant Engineering Manager and the Directors of Operations, Engineering, Maintenance, and Work Management (PSEG 2010a). The PHC is chartered with reviewing issues that require special plant management attention to ensure effective resolution and, with respect to each of the potentially cost-beneficial SAMAs, will decide on one of the following courses of actions: 1) approve for implementation, 2) conditionally approved for implementation pending the results of requested evaluations, 3) not approved for implementation, or 4) tabled until additional information needed to make a final decision is provided to the PHC. Additional requests may include 1) updating the SAMA analysis, 2) examining an alternate solution, 3) performing sensitivity studies to determine the effect of implementing a sub-set of SAMAs, already approved SAMAs, or already approved non-SAMA design changes on the SAMA, or 4) coordinating the SAMA with related Mitigating System Performance Index (MSPI) margin recovery activities. If approved or conditionally approved for implementation, the SAMA will be ranked with respect to priority and assigned target years for implementation.

The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the other SAMAs evaluated would be higher than the associated benefits.

F.7 Conclusions

PSEG compiled a list of 27 SAMAs based on a review of: the most significant basic events from the plant-specific PRA and insights from the SGS PRA group, insights from the plant-specific IPE and IPEEE, Phase II SAMAs from license renewal applications for other plants, and the generic SAMA candidates from NEI 05-01. A qualitative screening removed SAMA candidates that: (1) are not applicable to SGS due to design differences, (2) have already been implemented at SGS, (3) would achieve results that have already been achieved at SGS by other means, and (4) have estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at SGS. Based on this screening, 2 SAMAs were eliminated leaving 25 candidate SAMAs for evaluation. One additional SAMA candidate was identified and evaluated as a sensitivity case. Three additional SAMA candidates were identified and evaluated in response to an NRC staff RAI.

For the remaining SAMA candidates, including the sensitivity case SAMA and three SAMAs added in response to the NRC staff RAI, a more detailed design and cost estimate were developed as shown in Table F-6. The cost-benefit analyses in the ER and RAI response showed that 11 of the SAMA candidates were potentially cost-beneficial in the baseline analysis (Phase II SAMAs 1, 2, 4, 6, 9, 10, 11, 12, 14, 17, and 24). PSEG performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. As a result, five additional SAMA candidates (SAMA 3, 5, 7, 8, and 27) were identified as potentially cost-beneficial in the ER. The ER also showed that the sensitivity case SAMA (SAMA 5A) was potentially cost-beneficial. PSEG has indicated that all 17 potentially cost-beneficial SAMAs will be considered for implementation through the established Salem Plant Health Committee process.

The NRC staff reviewed the PSEG analysis and concludes that the methods used and the implementation of those methods was sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by PSEG are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited, the likelihood of there being cost-beneficial enhancements in this area was minimized by improvements that have been realized as a result of the IPEEE process, and inclusion of a multiplier to account for external events.

The NRC staff concurs with PSEG's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of the identified, potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the NRC staff agrees that further evaluation of these SAMAs by PSEG is warranted. However, these SAMAs do not relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal pursuant to Title 10 of the *Code of Federal Regulations*, Part 54.

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Appendix G

U.S. Nuclear Regulatory Commission Staff Evaluation of Severe Accident Mitigation Alternatives for Hope Creek Nuclear Generating Station In Support of License Renewal Application Review

G. U.S. Nuclear Regulatory Commission Staff Evaluation of Severe Accident Mitigation Alternatives for Hope Creek Nuclear Generating Station in Support of License Renewal Application Review

G.1 Introduction

PSEG Nuclear, LLC, (PSEG) submitted an assessment of severe accident mitigation alternatives (SAMAs) for the Hope Creek Generating Station (HCGS) as part of the environmental report (ER) (PSEG 2009). This assessment was based on the most recent HCGS probabilistic risk assessment (PRA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System, Version 2 (MACCS2) computer code, and insights from the HCGS individual plant examination (IPE) (PSEG 1994) and individual plant examination of external events (IPEEE) (PSEG 1997). In identifying and evaluating potential SAMAs, PSEG considered SAMAs that addressed the major contributors to core damage frequency (CDF) and release frequency at HCGS, as well as SAMA candidates for other operating plants that have submitted license renewal applications. PSEG initially identified 23 potential SAMAs. This list was reduced to 21 unique SAMA candidates by eliminating SAMAs that are not applicable to HCGS due to design differences, have already been implemented at HCGS, would achieve the same risk reduction results that had already been achieved at HCGS by other means, have excessive implementation cost or could be combined with another SAMA candidate. PSEG assessed the costs and benefits associated with each of the potential SAMAs, and concluded in the ER that several of the candidate SAMAs evaluated are potentially cost-beneficial.

Based on a review of the SAMA assessment, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) to PSEG by letter dated May 20, 2010 (NRC 2010a) and, based on a review of the RAI responses, a request for RAI response clarification by teleconference dated July 29, 2010 (NRC 2010b). The staff's requests concerned the following:

- discussing internal and external review comments on the PRA model, including the impact of the 2008 PRA peer review comments on the SAMA analysis results;
- the process and criteria used to assign containment event tree (CET) end states to release categories;
- additional details on the seismic analysis;
- the SAMA screening process and additional potential SAMAs not previously considered; and
- further information on the costs and benefits of several specific candidate SAMAs and low cost alternatives.

PSEG submitted additional information in response to the NRC requests by letters dated June 1, 2010 (PSEG 2010a) and August 18, 2010 (PSEG 2010b). In these response letters, PSEG provided the following:

- a listing of open gaps and findings from the 2008 PRA peer review and an assessment of their impact on the SAMA analysis;
- additional description of how CET end states were assigned to release categories and how representative sequences were selected for each release category;
- clarification of certain elements of the seismic analysis and an assessment of the impact of seismic assumptions on the external events multiplier;
- analyses of additional SAMAs; and
- additional information regarding several specific SAMAs.

PSEG's responses addressed the NRC staff's concerns, and resulted in the identification of additional potentially cost-beneficial SAMAs.

An assessment of SAMAs for HCGS is presented below.

G.2 Estimate of Risk for HCGS

PSEG's estimates of offsite risk at HCGS are summarized in Section G.2.1. The summary is followed by the NRC staff's review of PSEG's risk estimates in Section G.2.2.

G.2.1 PSEG's Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the HCGS Level 1 and Level 2 PRA model, which is an updated version of the IPE (PSEG 1994), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PRA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent HCGS Level 1 and Level 2 PRA model available at the time of the ER, referred to as the HC108B update. The scope of this HCGS PRA does not include external events.

The HCGS CDF is approximately 5.1×10^{-6} per year as determined from quantification of the Level 1 PRA model at a truncation of 1×10^{-12} per year. When determining the frequency of the source term categories from the sum of the containment event tree (CET) sequences, or Level 2 PRA model, a higher truncation of 5×10^{-11} per year was used and the resulting release frequency (from all release categories, which consist of intact containment, late release, and early release) is approximately 4.4×10^{-6} per year. The latter value was used as the baseline CDF in the SAMA evaluations (PSEG 2009). The CDF is based on the risk assessment for internally-initiated events, which includes internal flooding. PSEG did not explicitly include the contribution from external events within the HCGS risk estimates; however, it did account for the potential risk reduction benefits associated with external events by multiplying the estimated benefits for internal events by a factor of 6.3. This is discussed further in Sections G.2.2 and G.6.2.

The breakdown of CDF by initiating event is provided in Table G-1 (PSEG 2009). As shown in this table, events initiated by loss of offsite power, loss of service water and other transients (manual shutdown and turbine trip with bypass) are the dominant contributors to the CDF.

Anticipated transient without scram (ATWS) sequences account for 3% of the CDF, station blackout accounts for 12% of the CDF (PSEG 2010a).

Table G-1. HCGS Core Damage Frequency for Internal Events (PSEG 2009)

Initiating Event	CDF (per year)	% Contribution to CDF[1]
Loss of Offsite Power	9.3×10^{-7}	18
Loss of Service Water (SW)	8.1×10^{-7}	15
Manual Shutdown	7.7×10^{-7}	15
Turbine Trip with Bypass	6.2×10^{-7}	12
Small Loss of Coolant Accident (LOCA) – Water (Below Top of Active Fuel)	2.8×10^{-7}	5
Small LOCA – Steam (Above Top of Active Fuel)	2.3×10^{-7}	4
Loss of Condenser Vacuum	2.0×10^{-7}	4
Fire Protection System Rupture Outside Control Room	1.9×10^{-7}	4
Isolation LOCA in Emergency Core Cooling System (ECCS) Discharge Paths	1.1×10^{-7}	2
Main Steam Isolation Valve (MSIV) Closure	1.1×10^{-7}	2
Internal Flood Outside Lower Relay Room	9.7×10^{-8}	2
Loss of Feedwater	8.8×10^{-8}	2
Loss of Safety Auxiliaries Cooling System	7.9×10^{-8}	2
Reactor Auxiliaries Cooling System (RACS) Common Header Unisolable Rupture	7.6×10^{-8}	1
Unisolable SW A Pipe Rupture in RACS Room	5.7×10^{-8}	1
Unisolable SW B Pipe Rupture in RACS Room	5.7×10^{-8}	1
Others (less than 1% each)	4.1×10^{-7}	8
Total CDF (internal events)	$\mathbf{5.1 \times 10^{-6}}$	**100**

[1]Column totals may be different due to round off.

The Level 2 HCGS PRA model that forms the basis for the SAMA evaluation is essentially a complete revision to the IPE model. The Level 2 model utilizes three containment event trees (CETs) containing both phenomenological and systemic events. The Level 1 core damage sequences are binned into accident classes that provide the interface between the Level 1 and Level 2 CET analysis. The CETs are linked directly to the Level 1 event trees and CET nodes are evaluated using supporting fault trees.

The result of the Level 2 PRA is a set of 11 release or source term categories, with their respective frequency and release characteristics. The results of this analysis for HCGS are provided in Table E.3-6 of ER Appendix E (PSEG 2009). The categories were defined based on the timing of the release, the magnitude of the release, and whether or not the containment remains intact or fails. The frequency of each release category was obtained by summing the frequency of the individual accident progression CET endpoints binned into the release category. Source terms were developed for each of the 11 release categories using the results of Modular Accident Analysis Program (MAAP 4.0.6) computer code calculations.

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mile radius) for the year 2046, emergency response evacuation modeling, and economic data. The core radionuclide inventory corresponds to the end-of-cycle values for HCGS operating at 3917 MWt, which is two percent above the current extended power uprate (EPU) licensed power level of 3,840 MWt. The magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In the ER, PSEG estimated the dose to the population within 80-kilometers (50-miles) of the HCGS site to be approximately 0.23 person-Sievert (Sv) (22.9 person-roentgen equivalent man [rem]) per year. The breakdown of the total population dose by containment release mode is summarized in Table G-2. Releases from the containment within the early time frame (0 to less than 4 hours following event initiation) and intermediate time frame (4 to less than 24 hours following event initiation) dominate the population dose risk at HCGS.

Table G-2. Breakdown of Population Dose by Containment Release Mode

Containment Release Mode	Population Dose (Person-Rem[1] Per Year)	Percent Contribution [2]
Early Releases (< 4hrs)	11.9	52
Intermediate Releases (4 to <24 hrs)	9.9	43
Late Releases (≥24 hrs)	1.1	5
Intact Containment	<0.1	negligible
Total	**22.9**	**100**

[1]One person-rem = 0.01 person-Sv

[2]Derived from Table E.3-7 of the ER (PSEG 2009)

G.2.2 Review of PSEG's Risk Estimates

PSEG's determination of offsite risk at HCGS is based on the following three major elements of analysis:

- The Level 1 and 2 risk models that form the bases for the 1994 IPE submittal (PSEG1994), and the external event analyses of the 1997 IPEEE submittal (PSEG 1997),
- The major modifications to the IPE model that have been incorporated in the HCGS PRA, and
- The MACCS2 analyses performed to translate fission product source terms and release frequencies from the Level 2 PRA model into offsite consequence measures (essentially this equates to a Level 3 PRA).

Each of these analyses was reviewed to determine the acceptability of PSEG's risk estimates for the SAMA analysis, as summarized below.

The NRC staff's review of the HCGS IPE is described in an NRC report dated April 23, 1996 (NRC 1996). Based on a review of the IPE submittal and responses to RAIs, the NRC staff concluded that the IPE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the HCGS IPE has met the intent of GL 88-20 (NRC 1988).

During the performance of the IPE, transients involving heating, ventilation, and air conditioning (HVAC) failure were determined to contribute inordinately to the CDF. This was labeled a vulnerability and a procedure to provide alternate ventilation was developed. The implementation of this procedure removed this vulnerability. Credit for this procedure was taken in the HCGS IPE submittal. No other vulnerabilities were identified. In the ER, PSEG indicated that there were three improvements identified in the process of performing the IPE. Two of the improvements were performing refined calculations to allow increased credit for existing plant design features. The third was developing a procedure for operation of the Safety Auxiliaries Cooling System in severe accident conditions. All of these improvements are stated to have been implemented (PSEG 2009).

There have been twelve revisions to the IPE model since the 1994 IPE submittal. A listing of the changes made to the HCGS PRA since the original IPE submittal was provided in the ER (PSEG 2009) and in response to an RAI (PSEG 2010a) and is summarized in Table G-3. A comparison of internal events CDF between the 1994 IPE and the current PRA model indicates a decrease of about a factor of ten in the total CDF (from 4.7×10^{-5} per year to 5.1×10^{-6} per year). This reduction can be attributed to significant changes in success criteria, modeling details and removal of conservatism.

Table G-3. HCGS PRA Historical Summary (PSEG 2009)

PRA Version	Summary of Changes from Prior Model	Total CDF[1] (per year)
1994	IPE Submittal	4.7×10^{-5}
Model 0 9/1994	- Credit taken for beyond design basis performance of Safety Auxiliaries Cooling System (SACS) and Station Service Water System (SSWS) based on updated success criteria calculations.	1.3×10^{-5}
Model 1.0 7/1999	- Integrated the Level I and II models - Updated the database - Further developed sequence end states - Developed fault trees for special initiators - Reviewed dependent operator actions	1.9×10^{-5}
Model 1.3[2] 10/2000	- Requantified two important human error probabilities - Revised treatment of disallowed maintenance to credit plant procedures and operating practices. - Revised common cause failure assessment - Eliminated core spray room cooling dependency on SACS based on review of room heat up calculations - Added models for breaks outside containment and manual shutdown - Updated ATWS analysis	9.3×10^{-6}
Model 2003A 8/2003	- Incorporated resolution of 1999 BWROG peer review Facts and Observations (Attachment 14 to PSEG 2005) - Converted from NUPRA to CAFTA software - Performed completely new human reliability assessment - Revised accident sequence definitions - Performed new MAAP calculations for extended power uprate (EPU) conditions - Updated data - Modified system models - Updated common cause failure analysis - Added internal flood accident sequences	3.1×10^{-5}
Rev. 2.0 10/2004	- Modified 480 VAC dependencies - Modified SACS success criteria - Modified SACS-SW Human Error Probabilities	1.7×10^{-5}
Model 2005C[3] 2/2006	- Removed conservatism in the SACS-SW success criteria - Included more detailed logic for AC power supplies - Removed conservatism in operator action human error probabilities (HEPs) - Reduced turbine trip initiating event frequency	9.8×10^{-6}

PRA Version	Summary of Changes from Prior Model	Total CDF[1] (per year)
HC108A 8/2008	BWROG Peer Reviewed - Incorporated seasonal success criteria for SACS and SSWS - Updated internal flooding scenarios and initiating event frequencies to be consistent with ASME PRA standard - Credited use of portable battery charger for Station Blackout scenarios - Reassessed human error probabilities using Electric Power Research Institute (EPRI) human reliability analysis (HRA) calculator - Updated evaluation of dependent operator actions	7.6×10^{-6}
HC108B 12/2008	- Credited procedure changes for local manual manipulation of SSWS valves under LOOP conditions - Removed conservatism in modeling of 120 VAC inverter room cooling logic - Updated SACS pump failure probabilities to be consistent with Bayesian update values	5.1×10^{-6} (4.4×10^{-6})[4]

[1]Total CDF includes internal floods. Prior to Model 2003A, IPE internal flood analysis was retained.

[2]Changes for Model 1.3 includes those for prior intermediate Models 1.1 and 1.2. All changes were considered minor.

[3]Changes for Model 2005C includes those for prior intermediate Models 2005A and 2005B. All changes to Models 2005A and 2005B were considered minor.

[4]Model HC108B truncation limit was decreased to 1×10^{-12} per year from 5×10^{-11} per year utilized for the HC108A and 2005 models. The CDF in parentheses is the result based on the higher truncation limit.

The CDF value from the 1994 IPE (4.7×10^{-5} per year) is in the upper third of the values reported for other BWR 3/4 plants. Figure 11.2 of NUREG-1560 shows that the IPE-based total internal events CDF for BWR 3/4 plants ranges from 9×10^{-8} per year to 8×10^{-5} per year, with an average CDF for the group of 2×10^{-5} per year (NRC 1997b). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for HCGS (5.1×10^{-6} per year) are comparable to that for other plants of similar vintage and characteristics.

The NRC staff considered the peer reviews performed for the HCGS PRA, and the potential impact of the review findings on the SAMA evaluation. In the ER (PSEG 2009) and in response to an NRC staff RAI (PSEG 2010a) and in other unrelated submittals (PSEG 2005), PSEG described three BWROG Peer Reviews for the HCGS PRA. The first was a pilot of the BWROG peer review process conducted in 1996 of PRA Model 0. The second, conducted in 1999, reviewed PRA Model 1.0. The third, conducted in 2008, reviewed the HC108A Model.

The 1999 peer review identified no Level A (extremely important) and 80 Level B (important) Facts and Observations (F&Os). It was stated that these F&Os were resolved and incorporated in the 2003A PRA Model (PSEG 2005).

The 2008 peer review of the HC108A model was requested by PSEG because of the significant changes in PRA methods since the prior peer review. This peer review was performed using the Nuclear Energy Institute peer review process (NEI 2007) and the ASME PRA Standard (ASME 2005) as endorsed by the NRC in Regulatory Guide 1.200, Rev. 1 (NRC 2007). In the

ER PSEG summarizes the results of the peer review by reporting the number of ASME Standard's supporting requirements (SRs) that were assessed to meet each of the standard's Capability Categories. Of the 301 SRs applicable to HCGS, 286 were found to meet the requirements for Capability Category II or higher, seven met Capability Category I and eight did not meet any Capability Category. The 2005 ASME PRA standard describes Capability Category II as follows: 1) the scope and level of detail has resolution and specificity sufficient to identify the relative importance of significant contributors at the *component* level including human actions, as necessary, 2) *plant-specific* data/models are used for significant contributors, and 3) departures from realism will have *small* impact on the conclusions and risk insights as supported by good practices. Similarly, it describes Capability Category I as follows: 1) the scope and level of detail has resolution and specificity sufficient to identify the relative importance of significant contributors at the *system or train* level including human actions, 2) *generic* data/models are acceptable except for the need to account for the unique design and operational features of the plant, and 3) departures from realism will have *moderate* impact on the conclusions and risk insights as supported by good practices (ASME 2005)

In the ER, PSEG indicated that the SRs identified as "not met" were addressed in the HC108B model. In response to an NRC staff RAI, PSEG provided a listing and discussion of the resolution of the SRs that only met Capability Category I and of other Peer Review Finding-level F&Os (PSEG 2010a). It should be noted that a Finding-level F&O is essentially equivalent to and replaces the previously used Level A and B F&Os[1] and is defined as an observation that is necessary to address to ensure 1) the technical adequacy of the PRA, 2) the capability/robustness of the PRA update process, and 3) the process for evaluating the necessary capability of the PRA technical elements (NEI 2007).

Of the seventeen identified SRs and findings, thirteen were stated to have been resolved as part of the HC108B PRA update and re-assessed as meeting Capability Category II at a minimum as a result of additional investigation, analysis and/or documentation. Four of the SRs and findings remain open. In the discussion of the status and impact of these open items, PSEG concluded that the resolution of each would not impact the conclusions of the SAMA risk assessment. Two of the open items were documentation issues. One issue was related to the need for additional plant-specific data for important events. PSEG indicated that a review of HCGS recent experience indicates "no anomalous behavior" and that minor changes to component unavailability and unreliability values would not change the conclusions of the SAMA risk evaluation. The fourth issue was related to the identification, characterization and documentation of model uncertainties. PSEG indicated that a number of sensitivity evaluations were performed and that other areas of the HCGS PRA were investigated for potential impact on the PRA results but none were found to rise to the level of being candidates for modeling uncertainty. PSEG concluded that the resolution of this open item would not impact the conclusions of the SAMA evaluation (PSEG 2010a). PSEG further states that the HCGS PRA treatment of model uncertainty is considered to meet the requirements of the latest NRC guidance on model uncertainty, NUREG-1855 (NRC 2009).

[1] Earlier in the history of the PRA Peer Review process, F&Os were divided into four categories, from most (A) to least significant (D). "Findings" have taken the place of the former A and B level F&Os, while "Suggestions" are now used when citing what formerly would have been F&Os at the C and D level.

In the initial response to the NRC staff's RAIs (PSEG 2010a) PSEG's discussion of the resolution of the supporting requirements that were not met addressed only six items whereas the initial listing in the ER indicated that there were eight SRs that were not met. In response to the request for clarification PSEG stated that the final review report identified six SRs as not being met, but that the draft had cited eight (PSEG 2010b).

Based on review with respect to the requirements of the ASME PRA Standard, the NRC staff considers PSEG's disposition of the peer review findings to be reasonable and that final resolution of the findings is not likely to impact the results of the SAMA analysis.

The Revision HC108B model reflects the current (as of the date of the ER submittal) HCGS configuration and design. The licensee states that HCGS risk management personnel have reviewed plant modifications and procedure changes since the HC108B model freeze date. No changes were identified that required PRA model updates and therefore the licensee concluded that none of the plant modifications and procedure changes since the HC108B PRA update would impact the conclusions of the SAMA analysis. (PSEG 2010a, PSEG 2010b)

In response to an RAI, PSEG described the overall quality assurance program applicable to the HCGS PRA and its updates by providing descriptions of significant governing PSEG procedures. These procedures address the overall risk management program, risk management documentation including quality requirements for preparation, review and approval, configuration control and PRA model updates. Based on PSEG's procedures, the HCGS PRA is controlled with the appropriate requirements.

Given that the HCGS internal events PRA model has been peer-reviewed and the peer review findings with potential to impact SAMA evaluations were all dispositioned, and that PSEG has satisfactorily addressed NRC staff questions regarding the PRA, the NRC staff concludes that the internal events Level 1 PRA model is of sufficient quality to support the SAMA evaluation.

As indicated above, PSEG does not maintain a current HCGS external events PRA that explicitly models seismic and fire initiated core damage accidents that can be linked with the current Level 2 and 3 PRA. However, the models developed for seismic and fire events in the IPEEE were partially updated in 2003 to utilize revised initiating event frequencies and conditional core damage probabilities based on the 2003A internal events PRA Model. These results were used to identify SAMAs that address important fire and seismic risk contributors, as discussed below in Section G.3.2. The updated seismic and fire core damage results are described in ER Section E.5.1.7

The HCGS IPEEE was submitted in July 1997 (PSEG 1997), in response to Supplement 4 of Generic Letter 88-20 (NRC 1991a). The submittal included a seismic PRA, an internal fire PRA, and an evaluation of high winds, external flooding, and other hazards. While no fundamental weaknesses or vulnerabilities to severe accident risk in regard to the external events were identified, two potential enhancements were identified as discussed below. In a letter dated July 26, 1999 (NRC 1999), the NRC staff concluded that PSEGs IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities, and therefore, that the HCGS IPEEE has met the intent of Supplement 4 to Generic Letter 88-20.

The HCGS IPEEE seismic analysis utilized a seismic PRA following NRC guidance (NRC 1991a). The seismic PRA included: a seismic hazard analysis, a seismic fragility assessment, a seismic systems analysis, and quantification of seismic CDF.

The seismic hazard analysis estimated the annual frequency of exceeding different levels of ground motion. Seismic CDFs were determined for both the EPRI (EPRI 1989) and the Laurence Livermore National Laboratory (LLNL) (NRC 1994) hazard assessments. The seismic fragility assessment utilized the walkdown procedures and screening caveats in EPRI's seismic margin assessment methodology (EPRI 1991). Fragility calculations were made for about 90 components and, using a screening criterion of median peak ground acceleration (pga) of 1.5 g which corresponds to a 0.5 pga high confidence low probability of failure (HCLPF) capacity, a total of 17 components were screened in. The seismic systems analysis defined the potential seismic induced structure and equipment failure scenarios that could occur after a seismic event and lead to core damage. The HCGS IPE event tree and fault tree models were used as the starting point for the seismic analysis. Quantification of the seismic models consisted of convoluting the seismic hazard curve with the appropriate structural and equipment seismic fragility curves to obtain the frequency of the seismic damage state. The conditional probability of core damage given each seismic damage state was then obtained from the IPE models with appropriate changes to reflect the seismic damage state. The CDF was then given by the product of the seismic damage state probability and the conditional core damage probability.

The seismic CDF resulting from the HCGS IPEEE was calculated to be 3.6×10^{-6} per year using the LLNL seismic hazard curve and 1.0×10^{-6} per year using the EPRI seismic hazard curve. Both utilized the HCGS Model 0 internal events PRA, with a CDF of 1.3×10^{-5} per year for quantification of non-seismic failures.

The HCGS IPEEE did not identify any vulnerability due to seismic events or any potential improvements to reduce seismic risk. The IPEEE noted, however, that fire water tanks are not seismically robust and hence no credit was taken for the fire protection system in the seismic PRA. This is discussed further in Section G.3.2.

Subsequent to the IPEEE, PSEG updated the seismic PRA utilizing conditional core damage probabilities from the 2003A PRA model modified to reflect the seismic human reliability assessment that was performed to support the IPEEE, referred to as the HCGS 2003 External Events Update (PSEG 2009). The resulting seismic CDF using the EPRI seismic hazard curves is 1.1×10^{-6} per year. In the ER, PSEG provided a listing and description of the top ten seismic core damage contributors. The dominant seismic core damage contributors with a CDF of 1×10^{-8} per year or more are listed in Table G-4. In response to an NRC staff RAI, PSEG also determined the updated seismic CDF using the LLNL seismic hazard curve and the total seismic CDF was determined to be 3.6×10^{-6} per year. The seismic CDF utilizing the LLNL hazard curves for dominant seismic core damage contributors are also listed in Table G-4.

Table G-4. Dominant Contributors to the Seismic CDF (PSEG 2009)

		Based on EPRI Seismic Hazard Curves		Based on LLNL Seismic Hazard Curves	
Basic Event ID	**Seismic Sequence Description**	**CDF (per year)**	**% Contribution to Seismic CDF**	**CDF (per year)**	**% Contribution to Seismic CDF**
%IE-SET36	Seismic-Induced Equipment Damage State SET-36 (Impacts – 120V PNL481)	6.7×10^{-7}	60	2.5×10^{-6}	70
%IE-SET18	Seismic-Induced Equipment Damage State SET-18 (Impacts – LOOP)	3.1×10^{-7}	27	3.3×10^{-7}	9
%IE-SET37	Seismic-Induced Equipment Damage State SET-37 (Impacts – 125V)	6.8×10^{-8}*	6	4.4×10^{-7}	12
%IE-SET35	Seismic-Induced Equipment Damage State SET-35 (Impacts – 120V PNL482, RSP)	4.6×10^{-8}	4	1.6×10^{-7}	5
%IE-SET38	Seismic-Induced Equipment Damage State SET-38 (Impacts – 1E panel room Ventil.)	2.1×10^{-8}	2	5.4×10^{-8}	2

* In response to an RAI, PSEG indicated that the value reported in the ER page E-99 for this contributor was in error and should be that given in the IPEEE - 6.8×10^{-8} per year (PSEG 2010a).

For both hazard curves, the largest contributor to seismic CDF is a seismic-induced loss of all four divisions of 1E 120 VAC instrumentation distribution panels that leads directly to core damage. Other significant contributors are: for the EPRI hazard curves, a seismic-induced loss of offsite power which together with non-seismic random failures leads to core damage and, for the LLNL hazard curves, a seismic induced failure of all 125 VDC 1E power to loads that lead directly to core damage. The failure of all four 1E 120 VAC divisions and failure of all 125 VDC occur at a relatively high ground acceleration (a median failure at 1.08g and 1.47g, respectively) while the loss of offsite power occurs at a relatively low ground acceleration (a median failure of 0.31g) (PSEG 1997).

The NRC staff requested the applicant assess the impact the higher seismic CDF resulting from the use of the LLNL hazard curves would have on the external events multiplier and the results of the SAMA analysis as well as the impact of the increased CDF for important seismic sequences on the identification and evaluation of SAMAs for these sequences. This is discussed further below and in Sections G.3.2 and G.6.2.

The HCGS IPEEE fire analysis employed EPRI's fire-induced vulnerability evaluation (FIVE) methodology (EPRI 1993) to perform a fire compartment interaction analysis (FCIA) and a quantitative screening analysis. This was then followed by a PRA quantification of the unscreened compartments.

The FCIA identified 209 fire compartments meeting the FIVE criteria for the entire plant. The quantitative screening utilized a threshold fire ignition frequency obtained using the FIVE methodology and the assumptions that all fires resulted in a reactor trip or more severe transient and that any fire in a compartment damaged all the equipment and cables in the compartment. Using the assessed screening fire frequency and conservatively determined screening conditional core damage probabilities (CCDPs) from the Model 0 internal events PRA resulted in screening out (at a CDF of less than 1×10^{-6} per year) of all but 38 fire compartments.

The analysis for the unscreened areas employed a detailed probabilistic assessment of each possible fire initiator/target combination including intermediate fire growth stages. Fire damage calculations used a modified version of the FIVE fire propagation methodology. No explicit credit was taken for manual or automatic fire suppression. Final quantification utilized FIVE fire data and refined CCDPs from the Model 0 internal events PRA. The resulting fire induced CDF was calculated to be 8.1×10^{-5} per year. A walkdown and verification process was employed to verify that the assumptions and calculations were supported by the physical condition of the plant.

The HCGS IPEEE did not identify any vulnerabilities due to internal fires or any potential improvements to reduce internal fire risk.

Subsequent to the IPEEE, PSEG updated the fire PRA to incorporate more recent fire initiating event frequencies based on information in the 2002 NRC fire database and conditional core damage probabilities from the 2003A PRA model, referred to as the 2003 HCGS External Events Update. The resulting fire CDF is 1.7×10^{-5} per year.

In the ER, PSEG provided a listing and description of the top ten fire core damage contributors. The important fire core damage contributors with a CDF of 1×10^{-7} per year or more are listed in Table G-5. As can be seen from these results the fire risk at HCGS is dominated by panel fires in the control room.

Table G-5. Important Contributors to Fire CDF (PSEG 2009)

Basic Event ID	Fire Area Description	CDF per year	% Contribution to Fire CDF
%IE-FIRE03	Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)	5.3×10^{-6}	31
%IE-FIRE02	Control Room Fire Scenario Small Cab_2 (Loss of SSWS)	4.4×10^{-6}	25
%IE-FIRE01	Control Room Fire Scenario Small Cab_1 (Loss of SACS)	3.8×10^{-6}	22
%IE-FIRE28	Compartment 5339 Fire Scenario 5339_2	7.5×10^{-7}	4
%IE-FIRE37	DG room (D) Fire Scenario 5304_2	7.0×10^{-7}	4
%IE-FIRE20	DG room (C) Fire Scenario 5306_2	6.7×10^{-7}	4

Basic Event ID	Fire Area Description	CDF per year	% Contribution to Fire CDF
%IE-FIRE38	Compartment 3425/5401 Fire Scenario 5401_1	5.9×10^{-7}	3
%IE-FIRE06	Control Room Fire Scenario Large Cab_1 (MSIV Closure)	5.1×10^{-7}	3

In the ER, PSEG states that an effective comparison between the internal events PRA results and the fire analysis results is not possible because neither the plant response model nor the fire modeling methodology used in the updated fire model is current. PSEG identified in the ER areas where fire CDF quantification may introduce levels of uncertainty different from those expected in the internal events PRA, including a number of conservatisms in the fire modeling, as follows:

- Several system models assume the systems are unavailable or are unrecoverable in a fire. For example, any fire is assumed to result in a plant trip, even if it is not severe. Bounding fire modeling assumptions are used for many fire scenarios. For example, all cables are damaged in a fire even if they are enclosed in cable trays or conduit. Because of a lack of industry experience with regard to crew performance during the types of fires modeled in the fire PRA, the characterization of crew actions in the fire PRA is generally considered to be conservative.

PSEG’s conclusion is that while some of the conservatisms have been addressed in the updated fire model, the result is still believed to be conservative.

Considering the above discussion, the conservatisms in the updated fire PRA model as currently understood, and the response to the NRC staff RAIs, the NRC staff concludes that the fire CDF of 1.7×10^{-5} per year is reasonable for the SAMA analysis.
The IPEEE analysis of high winds, floods and other (HFO) external events indicated that each of the events identified in NUREG-1407 (NRC 1991b) had a core damage contribution of less than the screening criterion of 1×10^{-6} per year. This was done by either showing compliance with the 1975 Standard Review Plan criteria or by a bounding analysis that demonstrated that the CDF contribution was less than the screening criterion. For the SAMA analysis, PSEG assumed a CDF contribution of 1×10^{-6} per year for each of high winds, external floods, transportation and nearby facilities, detritus, and chemical releases, for a total HFO CDF contribution of 5×10^{-6} per year (PSEG 2009).

Although the HCGS IPEEE did not identify any vulnerabilities due to HFO events, two improvements to reduce risk were identified as described below.

For high winds, the HCGS design was compared to the SRP criteria and found to have a CDF contribution less than the screening criterion. A walkdown was performed to evaluate high wind hazards and as a result work was initiated to install a missile shield in front of a door into the Technical Support Center. This improvement has been implemented.

For external floods the HCGS was found to be adequately protected from the postulated occurrence of the probable maximum hurricane surge with wave run-up coincident with the high tide at the 10% exceedance level. HCGS was also found to comply with the latest probable maximum precipitation criteria. A walkdown confirmed that there were no severe accident vulnerabilities due to external floods.

A review of transportation and nearby facility accidents confirmed that there were no severe accident vulnerabilities from these accidents. During the review it was discovered that in a single year there had been some unauthorized shipments of explosives on the Delaware River in the vicinity of the HCGS. The U.S. Coast Guard (USCG), which controls such shipments, was contacted and procedures were put in place to prevent such shipments in the future. This improvement has been implemented.

The NRC staff asked about the status and potential impact on the SAMA analysis of a liquefied natural gas (LNG) terminal planned for Logan Township, New Jersey, upstream on the Delaware River from the HCGS site (NRC 2010a). In response to the RAI, PSEG discussed the current status of the LNG terminal as well as the regulatory controls for LNG marine traffic and LNG ship design and the safety record for LNG shipping (PSEG 2010a). The LNG terminal remains in the planning stage and no construction has begun. Further, the state of Delaware has denied applications for several required environmental permits and approvals. PSEG concluded that based on the regulatory process and controls for assuring the safety and security of LNG ships, the safety record of LNG ships and the uncertainty of the planned terminal, consideration of potential SAMAs associated with the possible future terminal is not warranted. The NRC staff agrees with this conclusion.

As indicated in the ER (PSEG 2009), a multiplier of 6.3 was used to adjust the internal event risk benefit associated with a SAMA to account for external events. This multiplier was based on a total external event CDF of 2.3×10^{-5} per year. This CDF is the sum of the updated fire CDF of 1.7×10^{-5} per year, the updated seismic CDF of 1.1×10^{-6} per year, and the HFO CDF of 5×10^{-6} per year. The external event CDF is thus approximately 5.3 times the internal events CDF of 4.4×10^{-6} per year used in the SAMA analysis at a truncation of 5×10^{-11} per year. The higher truncation used for determining the multiplier is to be consistent with that used to determine the release category frequencies and that used to evaluate the fire and seismic CDFs. The total CDF is thus 6.3 times the internal events CDF (PSEG 2009).

As indicated above, in response to an NRC staff RAI, PSEG determined the seismic CDF based on the LLNL hazard curve to be 3.6×10^{-6} per year (PSEG 2010a). If this is utilized instead of the value using the EPRI hazard curve, the total external events CDF is 2.6×10^{-5} per year and the external events multiplier is 6.8. The impact of this revised multiplier on the SAMA assessment is discussed further in Section G.3.2 and Section G.6.2.

The NRC staff reviewed the general process used by PSEG to translate the results of the Level 1 PRA into containment releases, as well as the results of the Level 2 analysis, as described in the ER and in response to NRC staff requests for additional information (PSEG 2010a, PSEG 2010b). The HCGS Level 2 PRA model is essentially a complete revision of the IPE Level 2 model, including completely revised containment event trees and system fault trees and completely updated thermal hydraulic analyses, incorporating the latest emergency operating procedures (EOPs), severe accident guidelines (SAGs), and emergency action level (EAL) and implementation using the Computer-Aided Fault Tree Analysis (CAFTA) software.

The current Level 2 model utilizes a set of three containment event trees (CETs) containing both phenomenological and systemic events. The Level 1 core damage sequences are grouped into core damage accident classes with similar characteristics. All the sequences in an accident class are then input to one of the three CETs by linking the level 1 event tree sequences with the level 2 CET. The CETs are analyzed by the linking of fault trees that represent each CET node. These fault trees are based on the Level 1 models for the system or function as modified for Level 2 considerations of timing, procedures, access or dependencies including recovery actions as documented in the HCGS emergency Operating Procedures and Severe Accident Management Guidelines.

Each CET end state represents a radionuclide release to the environment and is characterized by one of thirteen release bins based on magnitude and timing of release. Magnitude is given by cesium iodide (CsI) release fraction: High (H) > 10%, Moderate (M) 1% to 10%, Low (L) 0.1% to 1%, Low-Low (LL) <0.1% and negligible or no release<< 0.1%. Timing is given by time of initial release from the time of declaration of a General Emergency: Early (E) < 4 hours, Intermediate (I), 4 to 24 hours and Late (L) > 24 hours. The assignment of each end state to a given release bin is made on the basis of a MAAP calculation for the accident sequence or a similar MAAP calculated sequence. The thirteen release bins were subsequently refined into eleven release categories for input to the MELCOR Accident Consequence Code Systems (MACCS) consequence calculations by dividing the high early release bin into three release categories (high pressure, low pressure and breaks outside containment) and combining several of the end states with Low and Low-Low release magnitudes.

The frequency of each release category was obtained by summing the frequency of the contributing CET end states. The release characteristics for each release category were developed by using the results of Modular Accident Analysis Program (MAAP 4.0.6) computer code calculations. A representative MAAP case for each of the release categories was chosen based on a review of the Level 2 cutsets and the dominant types of scenarios that contribute to the results. The MAAP case chosen for each release category was generally the case with the highest consequence (PSEG 2010a). A description of the representative MAAP case for each release or source term category is provided in Table E.3-5 of the ER. The release categories, their frequencies, and release characteristics are presented in Table E.3-6 of the ER (PSEG 2009).

It is noted for the SAMA analysis the CET end state and release category frequencies were determined using a truncation value of 5×10^{-11} per year. This results in a total CDF of approximately 4.4×10^{-6} per year, which is about 16 percent less that the internal events CDF of 5.1×10^{-6} per year obtained when a truncation of 1×10^{-12} per year. The NRC staff considers that use of the release frequency rather than the Level 1 CDF will have a negligible impact on the results of the SAMA evaluation because the external event multiplier and uncertainty multiplier used in the SAMA analysis (discussed in Section G.6.2) have a much greater impact on the SAMA evaluation results than the small error arising from the model quantification approach.

The NRC staff review of release category information noted an apparent discrepancy in the release magnitude and release timing assigned for ST5 and ST7 and requested the applicant to clarify the reasons for these discrepancies (NRC 2010a). Both these release categories involve loss of containment heat removal with subsequent containment failure, core damage and fission product release. For ST5 the containment failure is in the wet well while for ST7 the containment failure is in the drywell. While the drywell failure would be expected to result in a higher release than a wet well failure, the reverse is true for the results provided in the ER. Further, the release timings were found to be slightly different even though the core damage times were the same. In response to the RAI, PSEG pointed out that the wet well failure for ST5 occurred below the water level and, due to the loss of suppression pool water inventory, resulted in significantly less cesium iodide removal from the safety relief valve (SRV) flow to the suppression pool for ST5 than for the drywell failure case ST7 (PSEG 2010a). The differing release pathways resulted in the slightly different times for the initiation of release to the environment.

Based on the NRC staff's review of the Level 2 methodology, the applicant's responses to RAIs and the fact that the Level 2 model was reviewed in more detail as part of the 2008 BWROG peer review and found to be acceptable (except for two documentation related findings which would not impact the SAMA analysis), the NRC staff concludes that the Level 2 PRA provides an acceptable basis for evaluating the benefits associated with various SAMAs.

The NRC staff reviewed the process used by PSEG to extend the containment performance (Level 2) portion of the PRA to an assessment of offsite consequences (essentially a Level 3 PRA). This included consideration of the source terms used to characterize fission product releases for the applicable containment release categories and the major input assumptions used in the offsite consequence analyses. The MACCS2 code was utilized to estimate offsite consequences. Plant-specific input to the code includes the source terms for each category and the reactor core radionuclide inventory (both discussed above), site-specific meteorological data, projected population distribution within an 80-kilometer (50-mile) radius for the year 2046, emergency evacuation modeling, and economic data. This information is provided in Section E.3 of Appendix E to the ER (PSEG 2009).

PSEG used the MACCS2 code and a core inventory from a plant specific calculation at end of cycle to determine the offsite consequences of activity release. In response to an NRC staff RAI, PSEG stated that the MACCS2 analysis was based on the core inventory used in the NRC-approved Alternate Source Term for HCGS (PSEG 2010a).

All releases were modeled as being from the top of the reactor containment building and at low thermal content (ambient). Sensitivity studies were performed on these assumptions and indicated little or no change in population dose or offsite economic cost. Assuming a ground level release decreased dose risk and cost risk by 6 percent and 7 percent, respectively. Assuming a buoyant plume decreased dose risk and cost risk by 1 percent. Based on the information provided, the staff concludes that the release parameters utilized are acceptable for the purposes of the SAMA evaluation.

PSEG used site-specific meteorological data for the 2004 calendar year as input to the MACCS2 code. The development of the meteorological data is discussed in Section E.3.7 of Appendix E to the ER. The data were collected from onsite and local meteorological monitoring systems. Sensitivity analyses using MACCS2 and the meteorological data for the years 2005 through 2007 show that use of data for the year 2004 results in the largest dose and economic cost risk. Missing meteorological data was filled by (in order of preference): using data from the backup met pole instruments (10-meter), using corresponding data from another level of the main met tower, interpolation (if the data gap was less than 6 hours), or using data from the same hour and a nearby day (substitution technique). The 10-meter wind speed and direction were combined with precipitation and atmospheric stability (derived from the vertical temperature gradient) to create the hourly data file for use by MACCS2. The NRC staff notes that previous SAMA analyses results have shown little sensitivity to year-to-year differences in meteorological data and concludes that the use of the 2004 meteorological data in the SAMA analysis is reasonable.

The population distribution the licensee used as input to the MACCS2 analysis was estimated for the year 2046 using year 1990 and year 2000 census data as accessed by SECPOP2000 (NRC 2003) as a starting point. In response to an NRC staff RAI, PSEG stated that the transient population was included in the 10-mile EPZ, and included prior to the population projection (PSEG 2010a). A ten year population growth rate was estimated using the year 1990 to year 2000 SECPOP2000 data and applied to obtain the distribution in 2046. The baseline population was determined for each of 160 sectors, consisting of sixteen directions for each of ten concentric distance rings to a radius of 50 miles surrounding the site. The SECPOP2000 census data from 1990 and 2000 were used to determine a ten year population growth factor for each of the concentric rings. The population growth was averaged over each ring and applied uniformly to all sectors within each ring. The NRC staff requested PSEG provide an assessment of the impact on the SAMA analysis if a wind-direction weighted population estimate for each sector were used (NRC 2010a). In response to the RAI, PSEG stated that the impacts associated with angular population growth rates on PDR and OECR are minimal and bounded by the 30% population sensitivity case (PSEG 2010a). This is based on the relatively even wind distribution profile surrounding the site, the tendency for lateral dispersion between sectors, and the use of mean values in the analysis. A sensitivity study was performed for the population growth at year 2040. A 30 percent increase in population resulted in a 29 percent increase in dose risk and a 30 percent increase in cost risk. In response to an NRC staff RAI, PSEG stated that the radial growth rates used in the MACCS2 analysis provides a more conservative population growth estimate than using ‘whole county’ data for averaging (PSEG 2010a). PSEG also identified that the population sensitivity case of 30 percent growth was approximately equivalent to adding 5.9 percent to the 10-year growth rate. The NRC staff considers the methods and assumptions for estimating population reasonable and acceptable for purposes of the SAMA evaluation.

The emergency evacuation model was modeled as a single evacuation zone extending out 16 kilometers (10 miles) from the plant (the emergency planning zone – EPZ). PSEG assumed that 95 percent of the population would evacuate. This assumption is conservative relative to the NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone. The evacuated population was assumed to move at an average radial speed of approximately 2.8 meters per second (6.3 miles per hour) with a delayed start time of 65 minutes after declaration of a general emergency (KLD 2004). A general emergency declaration was assumed to occur at the onset of core damage. The evacuation speed is a time-weighted average value accounting for season, day of week, time of day, and weather conditions. It is noted that the longest evacuation time presented in the study (i.e., full 10 mile EPZ, winter snow conditions, 99th percentile evacuation) is 4 hours (from the issuance of the advisory to evacuate). Sensitivity studies on these assumptions indicate that there is minor impact to the population dose or offsite economic cost by the assumed variations. The sensitivity study reduced the evacuation speed by 50 percent to 1.4 m/s. This change resulted in a 2 percent increase in population dose risk and no change in offsite economic cost risk. The NRC staff concludes that the evacuation assumptions and analysis are reasonable and acceptable for the purposes of the SAMA evaluation.

Site specific agriculture and economic parameters were developed manually using data in the 2002 National Census of Agriculture (USDA 2004) and from the Bureau of Economic Analysis (BEA 2008) for each of the 23 counties surrounding HCGS, to a distance of 50 miles. Therefore, recently discovered problems in SECPOP2000 do not impact the HCGS analysis. The values used for each of the 160 sectors were the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. Region-wide wealth data (i.e., farm wealth and non-farm wealth) were based on county-weighted averages for the region within 50-miles of the site using data in the 2002 National Census of Agriculture (USDA 2004) and the Bureau of Economic Analysis (BEA 2008). Food ingestion was modeled using the new MACCS2 ingestion pathway model COMIDA2 (NRC 1998a). For HCGS, less than one percent of the total population dose risk is due to food ingestion.

In addition, generic economic data that is applied to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 1.96, representing cost escalation from 1986 to April 2008 was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation.

The NRC staff concludes that the methodology used by PSEG to estimate the offsite consequences for HCGS provides an acceptable basis from which to proceed with an assessment of risk reduction potential for candidate SAMAs. Accordingly, the NRC staff based its assessment of offsite risk on the CDF and offsite doses reported by PSEG.

G.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by PSEG are discussed in this section.

G.3.1 Process for Identifying Potential Plant Improvements

PSEG's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- Review of the most significant basic events from the current, plant-specific PRA and insights from the HCGS PRA Group,
- Review of potential plant improvements identified in, and original results of, the HCGS IPE and IPEEE,
- Review of SAMA candidates identified for license renewal applications for six other U.S. nuclear sites, and
- Review of generic SAMA candidates from NEI 05-01 (NEI 2005) to identify SAMAs that might address areas of concern identified in the HCGS PRA.

Based on this process, an initial set of 23 candidate SAMAs, referred to as Phase I SAMAs, was identified. In this Phase I evaluation, PSEG performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- The SAMA is not applicable at HCGS due to design differences,
- The SAMA has already been implemented at HCGS,
- The SAMA would achieve results that have already been achieved at HCGS by other means, or
- The SAMA has estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at HCGS.

Based on this screening, one SAMA was eliminated, and one additional SAMA was eliminated by subsuming it into another SAMA. Therefore, 21 SAMAs required further evaluation. The results of the Phase I screening analysis is given in Table E.5-3 of Appendix E to the ER. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table E.6-1 of Appendix E to the ER. In Phase II a detailed evaluation was performed for each of the 21 remaining SAMA candidates, as discussed in Sections G.4 and G.6 below. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of 6.3, as previously discussed.

G.3.2 Review of PSEG's Process

PSEG's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events, but also included explicit consideration of potential SAMAs for important fire and seismic initiated core damage sequences. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from risk reduction worth (RRW) perspectives at HCGS, and included selected SAMAs from prior SAMA analyses for other plants.

PSEG provided a tabular listing of the Level 1 PRA basic events sorted according to their RRW (PSEG 2009). SAMAs impacting these basic events would have the greatest potential for reducing risk. PSEG used a RRW cutoff of 1.006, which corresponds to about a 0.6 percent change in CDF given 100-percent reliability of the SAMA.[2] This equates to a benefit of approximately $100,000 (after the benefits have been multiplied by a factor of 6.3 to account for external events), which is the minimum implementation cost associated with a procedure change.[3] As a result of this review, 11 SAMAs were identified.

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[2] Subsequently, PSEG extended the review down to a RRW of 1.005 to account for a revised external events multiplier of 6.8, as discussed in Section G.2.2.

[3] NUREG/BR-0184 provides calculational techniques by which reductions in risk can be equated to monetary values. The reverse calculation can convert monetary values, such as the cost of a procedure, to a risk reduction for the specific plant under consideration. In this way, the $100,000 cost of a site-wide procedure change equates to a RRW of 1.006, representing the potential to reduce risk by 0.6%. The subsequent use of a RRW of 1.005 represents the potential to reduce risk by 0.5% (NRC 1997a).

In the level 1 importance review, PSEG stated for the important initiating events that "this initiator event is a compilation of industry and plant specific data. (No specific SAMA identified)." The NRC staff requested that PSEG provide assurance that for each of these initiating events there is not a dominant contributor for which a potential SAMA to reduce the initiating event frequency or mitigate the impact of the initiator would be viable. In response to this RAI, PSEG discussed each of the initiators and the previously identified SAMAs that would reduce the importance of the initiator by mitigating other failures in the core damage sequences associated with these initiators (PSEG 2010a). In response to a request for clarification PSEG indicated that HCGS specific failures that are contributors to the initiating event frequencies that pose a unique vulnerability are typically captured and corrected within existing procedures, e.g., the corrective action program, and can result in procedure changes, plant modifications and training enhancements aimed at reducing further recurrence (PSEG 2010b). Based on this discussion and a review of the latest ten years of HCGS Licensee Event Reports, the NRC staff concludes that it is unlikely that further HCGS data review will identify any additional cost beneficial SAMAs beyond those already identified.

The PSEG response to the NRC staff request for clarification provided additional information on initiators modeled utilizing a fault tree approach rather then being based on initiating event data. For the loss of station auxiliaries cooling system initiating event (%IE-SACS), PSEG identified and evaluated SAMA 42, "Installation of SACS Standby Diesel-Powered Pump" (PSEG 2010b).

For an event involving the station service water system (NR-IE-SWS, "Nonrecovery of %IE-SWS"), the importance review identified two SAMAs as potentially mitigating this event: SAMA 3, "Install Back-up Air Compressor to Supply Air-Operated Valves (AOVs)," and SAMA 4, "Provide Procedural Guidance to Cross-Tie Residual Heat Removal (RHR) Trains." In response to an NRC staff RAI to clarify the source and applicability of these SAMAs to this event, PSEG discussed the modeling involving the NR-IE-SWS event and the applicability of the SAMAs in terms of the more general loss of decay heat removal function of which the event is associated and other SAMAs that would mitigate this event (PSEG 2010a). Based on this discussion, the NRC staff concludes that this event is adequately addressed in the SAMA analysis.

For a significant number of the Level 1 events reviewed no SAMAs were identified with the reason stated to be that "…based on low contribution to L[evel] 1 risk and engineering judgment, the anticipated implementation costs of hardware mods associated with mitigating this event would likely exceed the expected cost-risk benefit" (PSEG 2009). In response to an NRC staff RAI, PSEG provided a revised assessment of each of these events that showed that each was either already addressed by an existing SAMA or that no effective SAMAs could be identified (PSEG 2010a).

The NRC staff also requested PSEG to specifically consider the following proposed SAMAs to address basic events on the Level 1 importance list for which no SAMA was identified (NRC 2010a):

- Install a diverse redundant temperature controller to address basic event SAC-XHE-MC-DF01, "dependent failure of miscalibration of temperature controller HV-2457S." In response to the RAI, PSEG explained that this SAMA is not warranted since 1) procedures are already in place to manually control the affected system which, if credited using a failure probability of 0.1, would reduce the RRW for this basic event to

1.005, the revised review threshold (discussed below), and 2) controller miscalibration would be observed during normal operation (PSEG 2010a).

- Install flood barriers to address basic event %FL-FPS-5302, “internal flood outside lower relay room.” In response to the RAI, PSEG clarified that the ER incorrectly did not identify SAMA 8, “Convert Selected Fire Protection Piping from Wet Pipe to Dry Pipe System,” to address this event and further explained that the proposed SAMA is not necessary because the conversion to a dry pipe system was considered preferable to developing flood barriers considering the multiple doors that exist in the corridor outside the relay room (PSEG 2010a).

- Install a spray shield to address basic event SWS-MOV-VF-SPRAY, “flood – spray causes motor-operated valve (MOV) failure in reactor auxiliaries cooling system (RACS) compartment.” In response to the RAI, PSEG explained that the proposed SAMA is not required because the PRA conservatively assumes that all relevant spray events cause failure of the MOVs and that an assumption of 1 in 10 events causing failure would reduce the RRW for this basic event to below the 1.005 revised review threshold (PSEG 2010a).

- Installation of a passive containment vent to address basic event NR-RHRVENT-INT, “fail to initiate vent given failure to initiate residual heat removal (RHR) in suppression pool cooling (SPC).” This proposed SAMA would also be an alternative to SAMA 4, “Provide Procedural Guidance to Cross-tie RHR Trains.” In response to the RAI, PSEG indicated that changing the existing hard pipe venting system to a passive vent design is not considered feasible due to the loss in response flexibility provided by the existing hard pipe venting system and the potential for premature opening of the rupture disks in the passive design (PSEG 2010a). In response to a request for clarification PSEG identified and evaluated SAMA 41, “Installation of Passive Hardened Containment Ventilation Pathway” (PSEG 2010b).

In summary, as a result of PSEG’s reconsideration of basic events for which no SAMA had been identified in the ER, two new SAMAs were identified: SAMA 41, “Installation of Passive Hardened Containment Ventilation Pathway,” and SAMA 42, “Installation of SACS Standby Diesel-Powered Pump.” A Phase II cost-benefit evaluation was performed for each of these additional SAMAs, which is discussed in Section G.6.2.

In response to an NRC staff RAI, PSEG extended the review down to a RRW of 1.005 to account for a revised external events multiplier of 6.8, which was discussed in Section G.2.2. This extended review identified one additional SAMA as follows: SAMA RAI 5.j-IE1, “Install a Key Lock Switch for Bypass of the MSIV Low Level Isolation Logic” (PSEG 2010a, PSEG 2010b). The Phase II cost-benefit evaluation of this SAMA is discussed in Section G.6.2.

PSEG also provided and reviewed the Level 2 PRA basic events, down to a RRW of 1.006, for cutsets stated to contribute to large early release. This review did not identify any additional SAMAs. In response to an NRC staff RAI, PSEG revisited this review using only the cutsets from the high and moderate release categories, which contribute over 99 percent of the population dose-risk and offsite economic cost risk (PSEG 2010a). The Level 2 basic events for the remainder of the release categories were not included in the review so as to prevent high frequency-low consequence events from biasing the importance listing. In addition the review was extended down to a RRW of 1.005 to account for a revised external events multiplier of 6.8. The revisited review identified one additional SAMA, not identified in the extended Level 1 review discussed above, as follows: SAMA RAI 5p-1, “Install an Independent Boron Injection System." The Phase II cost-benefit evaluation of this SAMA is discussed in Section G.6.2.

The NRC staff also requested PSEG to specifically consider the following proposed SAMAs (NRC 2010a):

1. Installation of a curb or barrier inside the drywell to prevent early failure of the drywell shell due to shell melt-through. This proposed SAMA addresses basic event CNT-DWV-FF-MLTFL, “drywell (DW) shell melt-through failure due to containment failure,” for which no SAMA was identified. In response to the RAI, PSEG explained that this proposed SAMA would not be effective in reducing risk because 1) injection is not available and, without cooling, the core debris would degrade the barrier to the point of failure, and 2) an early unscrubbed release pathway is already available as a result of pre-existing containment failures resulting from loss of decay heat removal (PSEG 2010a).

2. Replacement of the normally open floor and equipment drain MOVs with fail-closed air-operated valves (AOVs). While this proposed SAMA is stated in the ER to be a more costly alternative to SAMA 5, “restore AC power with onsite gas turbine generator,” the NRC staff noted in the RAI that it might also be more effective and therefore have a larger benefit. In response to the RAI, PSEG provided a Phase II cost-benefit evaluation of this proposed SAMA, which is discussed in Section G.6.2.

One additional SAMA, SAMA 18, “replace a return fan with a different design in service water pump room,” was identified in the ER based on a review of PRA insights from the HCGS PRA Group and was identified to address two basic events on the Level 1 basic events importance list.

PSEG reviewed the cost-beneficial Phase II SAMAs from prior SAMA analyses for five General Electric BWR and one Westinghouse PWR sites. PSEG’s review determined that all but two of the Phase II SAMAs reviewed were either already represented by an existing SAMA, are already implemented at HCGS, have low potential for risk reduction at HCGS, or were not applicable to the HCGS design. This review resulted in two SAMAs being identified by PSEG for HCGS.

PSEG’s disposition of industry SAMA “auto align 480V AC portable station generator” is stated to be addressed by SAMA 5, “restore AC power with onsite gas turbine generator.” The NRC staff noted that the industry SAMA could mitigate events other than those addressed by SAMA 5 and requested PSEG to evaluate the industry SAMA (NRC 2010a). In response to an NRC staff RAI PSEG identified and evaluated an additional SAMA to automate the alignment of the portable 480V AC generator (PSEG 2010a, PSEG 2010b). The cost-benefit evaluation of this additional SAMA is discussed in Section G.6.2.

The ER states that an industry SAMA to "develop a procedure to open the door of the EDG buildings upon the higher temperature alarm" was included in the HCGS SAMA analysis. The NRC staff noted that no such SAMA was evaluated and asked PSEG to clarify this discrepancy (NRC 2010a). In response to the RAI, PSEG explained that this SAMA would not reduce HCGS risk since EDG room cooling issues are small contributors to risk at HCGS and that the statement in the ER is incorrect (PSEG 2010a).

The NRC asked PSEG to address a SAMA to "increase boron concentration or enrichment in the SLC system," which was determined to be potentially cost-beneficial in the Duane Arnold SAMA analysis (NRC 2010a). In response to the RAI, PSEG explained that this SAMA would have a negligible benefit at HCGS because Standby Liquid Control (SLC) is automatically initiated at HCGS and the basic events the SAMA addresses (related to manual SLC initiation) are not on the importance lists (PSEG 2010a).

PSEG considered the potential plant improvements described in the IPE in the identification of plant-specific candidate SAMAs for internal events. Review of the IPE led to no additional SAMA candidates since the three improvements identified in the IPE have already been implemented at HCGS. (PSEG 2009)

Based on this information, the NRC staff concludes that the set of SAMAs evaluated in the ER, together with those identified in response to NRC staff RAIs, addresses the major contributors to internal event CDF.

Although the IPEEE did not identify any fundamental vulnerabilities or weaknesses related to external events, two improvements related to HFO events were identified. The two improvements have been implemented at HCGS (PSEG 2009). In the ER PSEG also identified three post IPEEE site changes to determine if they could impact the IPEEE results and possibly lead to a SAMA. From this review no additional SAMAs were identified.

In a further effort to identify external event SAMAs, PSEG identified the top 10 fire scenarios contributing to fire CDF based on the results of the updated HCGS fire PRA model and reviewed the top 8 fire scenarios for potential SAMAs. These 8 scenarios are the only HCGS fire scenarios having a benefit equal to or greater than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS.[4] The maximum benefit for a fire area is the dollar value associated with completely eliminating the fire risk in that fire area. SAMAs having an implementation cost of less than that of a procedure change, or $100,000, are unlikely. As a result of this review, PSEG identified six Phase I SAMAs to reduce fire risk. The SAMAs identified included both procedural and hardware alternatives (PSEG 2009). The NRC staff concludes that the opportunity for fire-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, fire-related SAMA candidates.

[4] Salem, which is a dual-unit site, also assumes this $100,000 cost for a procedure change, but this is halved to $50,000 for each unit.

For seismic events, PSEG reviewed the top 10 seismic sequences contributing to seismic CDF based on the results of the 2003 HCGS seismic analysis and initially reviewed the top 2 seismic sequences for potential SAMAs. These two sequences are the only HCGS seismic sequences having a benefit equal to or greater than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS. The maximum benefit for a seismic sequence is the dollar value associated with completely eliminating the seismic risk for that sequence. SAMAs having an implementation cost of less than that of a procedure change, or $100,000, are unlikely. As a result of this review, PSEG identified three Phase I SAMAs to reduce seismic risk (PSEG 2009).

In response to an NRC staff RAI, PSEG revised the review of seismic sequences to account for the increased maximum benefit of each sequence resulting from the use of the LLNL seismic hazard curve instead of the EPRI curve used initially, as discussed in Section G.2.2. This resulted in two additional seismic sequences having a benefit equal to or greater than the $100,000 threshold. As a result of the review of these sequences three additional SAMAs were identified: 1) reinforce 1E 125V DC distribution panels 1A/B/C/D-D-417, 2) reinforce 1E 120V AC distribution panels 1A/B/C/DJ482, and 3) reinforce the 1E 120V AC 481 distribution panels to 1.0g Seismic Rating (PSEG 2010a, PSEG 2010b). The cost-benefit evaluation of these additional SAMAs is discussed in Section G.6.2.

The NRC staff concludes that the opportunity for seismic-related SAMAs has been adequately explored and that it is unlikely that there are additional potentially cost-beneficial, seismic-related SAMA candidates.

As stated earlier, other external hazards (high winds, external floods, transportation and nearby facility accidents, release of on-site chemicals, and detritus) are below the IPEEE threshold screening frequency, or met the 1975 SRP design criteria, and are not expected to represent vulnerabilities. Nevertheless, PSEG reviewed the IPEEE results and subsequent plant changes for each of these external hazards and determined that either 1) the maximum benefit from eliminating all associated risk was less than approximately $100,000, which is the approximate value of implementing a procedure change at a single unit at HCGS, or 2) only hardware enhancements that would significantly exceed the maximum value of any potential risk reduction were available. As a result of this review, PSEG identified no additional Phase I SAMAs to reduce HFO risk (PSEG 2009). Based on it being extremely unlikely that any hardware enhancement could be implemented for less than the cost of a procedural change ($100,000), the NRC staff concludes that the licensee's rationale for eliminating other external hazards enhancements from further consideration is reasonable.

The NRC staff noted that, while the generic SAMA list from NEI 05-01 (NEI 2005) was stated to have been used in the identification of SAMAs for HCGS, it was not specifically reviewed to identify SAMAs that might be applicable to HCGS but rather was used to identify SAMAs that might address areas of concern identified in the HCGS PRA (NRC 2010a). The NRC staff asked PSEG to provide further information to justify that this approach produced a comprehensive set of SAMAs for consideration. In response to the RAI, PSEG explained that, based on the early SAMA reviews, both the industry and NRC came to realize that a review of the generic SAMA list was of limited benefit because they were consistently found to not be cost-beneficial and that the real benefit was considered to be in the development of SAMAs generated based on plant specific risk insights from the PRA models (PSEG 2010a).

Furthermore, while the generic list does include potential plant improvements for plants having a similar design to HCGS, plant designs are sufficiently different that the specific plant improvements identified in the generic list are generally not directly applicable to HCGS, and require alteration to specifically address the HCGS design and risk contributors or otherwise would be screened as not applicable to the HCGS design. The NRC staff considers PSEG's limited use of the NEI 05-01 generic SAMA list as only an idea source to generate SAMAs that address important contributors to SGS risk reasonable for this particular HCGS application. .

The NRC staff noted that the 23 Phase I SAMA numbers were not consecutive from 1 to 23, but rather were intermittently numbered between 1 and 40 and requested clarification on the process used to develop the Phase I SAMA list (NRC 2010a). In response to the RAI, PSEG clarified that the original SAMA list was generated from an importance list using the HC108A PRA model, and that review of the subsequent importance list developed using the HC108B PRA model determined that certain SAMAs were either no longer applicable or were subsumed into other existing SAMAs (PSEG 2010a). PSEG further clarified that the resulting set of Phase I SAMAs was not renumbered to be consecutive so as to avoid configuration management errors that could occur when working with other documentation and supplemental files. Also, SAMAs identified from the review of external events were given a starting number of 30 so as to avoid overlap with SAMAs developed for internal events.

As indicated above two Phase 1 SAMAs were screened out. SAMA 38, "Enhance Fire Water System (FWS) and Automatic Depressurization System (ADS) for Long-term Injection," was screened out on the basis that a procedure has been implemented to address the actions associated with this SAMA. However, as discussed in ER Section E.5.1.7.2.2, this SAMA requires enhancement to the FWS, including strengthening the fire water tanks. In response to an NRC staff RAI, PSEG provided an additional discussion regarding this SAMA and how enhancements to the FWS have been addressed as part of the implementation of the current procedure (PSEG 2010a). The additional discussion indicated that the seismic sequence from which this SAMA originated was a low magnitude earthquake for which there would be a relatively small chance for failure of the FWS. Consequently, strengthening the FWS would have little impact on the sequence and, upon reevaluation, is not needed as part of SAMA 38. PSEG therefore concluded that the procedure implements the remaining requirements of this SAMA.

SAMA 14, "Alternate Room Cooling for Service Water (SW) Rooms," was screened out on the basis that it was subsumed into SAMA 4, "cross-tie RHR pump trains." It is described as providing an alternate means of opening Torus Vent Valves, but no basic event in the importance lists is identified as being addressed by this SAMA. In response to an NRC staff RAI, PSEG provided a further discussion of this SAMA and its disposition (PSEG 2010a). SAMA 14 was originally developed to address important containment venting failure events. The importance of these events would be reduced if the need to vent containment is reduced by addressing failure of SW room cooling which leads to loss of containment heat removal. It was subsequently determined that SAMA 4 was the most viable SAMA to address the loss of containment heat removal and SAMA 14 was subsumed into SAMA 4. PSEG also indicated that a loss of SW room cooling could also be addressed by a new SAMA that provides an alternate room cooling strategy for the SW room using procedures and portable fans. A Phase II detailed evaluation was performed for this new SAMA, referred to as SAMA RAI 7.a-1, "enhance procedures and provide additional equipment to respond to loss of all service water pump room supply or return fans" (PSEG 2010a).

The NRC staff questioned PSEG about lower cost alternatives to some of the SAMAs evaluated (NRC 2010a), including:

- Establishing procedures for opening doors and/or using portable fans for sequences involving room cooling failures.

- Extending the procedure for using the B.5.b low pressure pump for non-security events to include all applicable scenarios, not just SBOs.

- Utilizing a portable independently powered pump to inject into containment.

In response to the RAIs, PSEG addressed the suggested lower cost alternatives (PSEG 2010a). A new SAMA, SAMA RAI 7.a-1 discussed above, was assessed in a Phase II detailed evaluation for the first item while the other two items are effectively covered by existing procedures. This is discussed further in Section G.6.2.

The NRC staff notes that the set of SAMAs submitted is not all-inclusive, since additional, possibly even less expensive, design alternatives can always be postulated. However, the NRC staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

The NRC staff concludes that PSEG used a systematic and comprehensive process for identifying potential plant improvements for HCGS, and that the set of potential plant improvements identified by PSEG is reasonably comprehensive and, therefore, acceptable. This search included reviewing insights from the plant-specific risk studies, and reviewing plant improvements considered in previous SAMA analyses. While explicit treatment of external events in the SAMA identification process was limited, it is recognized that the prior implementation of plant modifications for fire and seismic risks and the absence of external event vulnerabilities reasonably justifies examining primarily the internal events risk results for this purpose.

G.4 Risk Reduction Potential of Plant Improvements

PSEG evaluated the risk-reduction potential of the 21 remaining SAMAs that were applicable to HCGS, and additional SAMAs identified in response to NRC staff RAIs. The SAMA evaluations were performed using realistic assumptions with some conservatism. On balance, such calculations overestimate the benefit and are, therefore, conservative.

PSEG used model re-quantification to determine the potential benefits. The CDF, population dose reductions, and offsite economic cost reductions were estimated using the HCGS PRA model. The changes made to the model to quantify the impact of SAMAs are detailed in Section E.6 of Appendix E to the ER (PSEG 2009). Table G-6 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The estimated benefits reported in Table G-6 reflect the combined benefit in both internal and external events. The determination of the benefits for the various SAMAs is further discussed in Section G.6.

The NRC staff questioned the assumptions used in evaluating the benefit or risk reduction estimate of SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator." The assessment of this SAMA assumed this was equivalent to reducing the probability of failure to cross tie the HCGS emergency diesel generators. This assumption does not provide credit for the gas turbine generator (GTG) in the situation where all the emergency generators are unavailable (NRC 20010a). In response to the RAIs, PSEG provided the results of a sensitivity study which the NRC staff subsequently noted did not appear to include credit for the hardware changes included in the cost estimate (NRC 2010b). In response to the request for clarification, PSEG provided the results of a re-evaluation of SAMA 5 that incorporated the additional capability for mitigating a more complete set of loss of offsite power initiators consistent with the hardware changes proposed (PSEG 2010b). The revised results are provided in Table G-6.

For SAMAs that specifically addressed fire events (i.e., SAMA 30, "Provide Procedural Guidance for Partial Transfer of Control Functions from Control Room to the Remote Shutdown Panel," SAMA 31, "Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits," SAMA 32, "Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from Diesel Generator (DG) Rooms," SAMA 33, "Install Division II 480V AC Bus Cross-ties," SAMA 34, "Install Division I 480V AC Bus Cross-ties," and SAMA 35, "Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room"), the reduction in fire CDF and population dose was not directly calculated (in Table G-6 this is noted as "Not Estimated"). For these SAMAs, an estimate of the impact was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to fire events; the fraction of the fire risk affected by the SAMA (based on information from the 2003 HCGS External Events Update); and the assumption that the SAMA eliminates 90 percent (SAMAs 30, 32, 33, and 34), 99 percent (SAMA 35), or all (SAMA 31) of the fire risk affected by the SAMA. Specifically, it is assumed that the contribution to risk from external events is approximately 5.3 times that from internal events, and that internal fires contribute 74 percent of this external events risk. The fire basic events impacted by the SAMA are identified and the portion of the total fire risk contributed by each of these fire basic events determined. For SAMA 31, the benefit or averted cost risk from reducing the fire risk affected by the SAMA is then calculated by multiplying the ratio of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. For the other fire SAMAs, the benefit or averted cost risk from reducing the fire risk affected by the

SAMA is then calculated by multiplying the ratio of 90 percent, or 99 percent (SAMA 35), of the fire risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. These SAMAs were assumed to have no additional benefits in internal events.

The NRC staff questioned the calculated impact for SAMA 35 which assumed that 90 percent of the fire risk affected by the SAMA was eliminated rather than the 99 percent stated in the ER (NRC 2010a). In response to the RAI, PSEG provided a revised evaluation using 99 percent (PSEG 2010a). The revised results are provided in Table G-6.

For SAMAs that specifically addressed seismic events (i.e., SAMA 36, “Provide Procedural Guidance for Loss of All 1E 120V AC Power,” and SAMA 37, “Reinforce 1E 120V AC Distribution Panels“) the reduction in seismic CDF and population dose also was not directly calculated. As was done for fire SAMAs, an estimate of the impact of seismic SAMAs was made based on general assumptions regarding: the approximate contribution to total risk from external events relative to that from internal events; the fraction of the external event risk attributable to seismic events; the fraction of the seismic risk affected by the SAMA (based on information from the 2003 HCGS External Events Update); and the assumption that the SAMA eliminates 50 percent (SAMA 36) or 90 percent (SAMA 37) of the seismic risk affected by the SAMA. Specifically, it is assumed that the contribution to risk from external events is approximately 5.3 times that from internal events, and that seismic events contribute 5 percent of this external events risk. The seismic basic events impacted by the SAMA are identified and the portion of the total seismic risk contributed by each of these seismic basic events determined. The benefit or averted cost risk from reducing the seismic risk affected by the SAMA is then calculated by multiplying the ratio of 50 percent (SAMA 36), or 90 percent (SAMA 37), of the seismic risk affected by the SAMA to the internal events CDF by the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS. These SAMAs were assumed to have no additional benefits in internal events.

The NRC staff has reviewed PSEG’s bases for calculating the risk reduction for the various plant improvements and concludes, with the above clarifications, that the rationale and assumptions for estimating risk reduction are reasonable and generally conservative (i.e., the estimated risk reduction is higher than what would actually be realized). Accordingly, the NRC staff based its estimates of averted risk for the various SAMAs on PSEG’s risk reduction estimates.

Table G-6. SAMA Cost/Benefit Screening Analysis for HCGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
1 – Remove Automatic Depressurization System (ADS) Inhibit from Non-ATWS Emergency Operating Procedures	**The probability that operators fail to inhibit ADS was reduced to 0.1 from 1.0.**	**26**	**29**	**5.3M**	**14.9M**	**200K**
3 – Install Back-up Air Compressor to Supply AOVs	**The probability that operators fail to restore service water was reduced to 0.5 from 1.0.**	**16**	**16**	**3.3M**	**9.4M**	**700K**
4 – Provide Procedural Guidance to Cross-Tie RHR Trains	**The probability that operators fail to recover RHR was reduced to 0.1 from 0.35.**	**12**	**21**	**4.4M**	**12.4M**	**100K**
5[b] – Restore AC Power with Onsite Gas Turbine Generator	**The probability that operators fail to cross-tie the emergency diesel generators (EDGs) was reduced to 0.1 from 1.0. In response to an NRC staff RAI, the GTG failure probability, maintenance unavailability, and human error probability were set to 0.**	**9**	**11**	**2.2M**	**6.3M**	**2.05M**
7 – Install Better Flood Protection Instrumentation for Reactor Auxiliaries Cooling System (RACS) Compartment	The probability that operators fail to isolate locally a service water rupture in the RACS compartment was reduced to 0.1 from 1.0.	4	2	330K	930K	3.07M
8 – Convert Selected Fire Protection Piping from Wet to Dry Pipe System	**The probability that operators fail to isolate a fire protection header leak was reduced to 0.1 from 1.0.**	**4**	**1**	**300K**	**860K**	**600K**

Table G-6. SAMA Cost/Benefit Screening Analysis for HCGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
10 – Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events	**The probability that operators fail to align residual heat removal service water (RHRSW) for injection into the reactor pressure vessel (RPV) was reduced to 1.0E-02 from 1.0E-01.**	**1**	**1**	**200K**	**570K**	**100K**
15 – Alternate Design of Core Spray System (CSS) Suction Strainer to Mitigate Plugging	The probability that operators fail to locally open each of the service water valves was reduced to 8.36E-04 from 8.36E-03.	2	1	130K	360K	1.0M
16 – Use of Different Designs for Switchgear Room Cooling Fans	The probability that FANS AVH401 through DVH400 fail-to-start and fail-to-run was set to 0.	2	1	130K	370K	400K
17 – Replace a Supply Fan with a Different Design in Service Water Pump Room	**The probability that FANS AV503 through DV503 fail-to-start and fail-to-run was set to 0.**	**5**	**5**	**960K**	**2.7M**	**600K**
18 – Replace a Return Fan with a Different Design in Service Water Pump Room	**The probability that FANS AV504 through DV504 fail-to-start and fail-to-run was set to 0.**	**5**	**5**	**960K**	**2.7M**	**600K**
30 – Provide Procedural Guidance for Partial Transfer of Control Functions from Control Room to the Remote Shutdown Panel	**Reduce the fire CDF contribution from Fire Basic Events %IE-FIRE03, %IE-FIRE02, and %IE-FIRE01 by 90 percent.**	**NOT ESTIMATED**		**8.6M**	**24M**	**100K**
31 – Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits	Eliminate the fire CDF contribution from Fire Basic Event %IE-FIRE06.	NOT ESTIMATED		360K	1.0M	1.2M

Table G-6. SAMA Cost/Benefit Screening Analysis for HCGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
32 – Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from Diesel Generator (DG) Rooms	**Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE28 by 90 percent.**	**NOT ESTIMATED**		**480K**	**1.4M**	**800K**
33 – Install Division II 480V AC Bus Cross-ties	Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE37 by 90 percent.	NOT ESTIMATED		450K	1.3M	1.32M
34 – Install Division I 480V AC Bus Cross-ties	Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE20 by 90 percent.	NOT ESTIMATED		430K	1.2M	1.32M
35 – Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room	**Reduce the fire CDF contribution from Fire Basic Event %IE-FIRE38 by 99 percent.**	**NOT ESTIMATED**		**410K[c]**	**1.2M[c]**	**270K**
36 – Provide Procedural Guidance for Loss of All 1E 120V AC Power	**Reduce the seismic CDF contribution from Seismic Basic Event %IE-SET36 by 50 percent.**	**NOT ESTIMATED**		**240K**	**680K**	**270K**
37 – Reinforce 1E 120V AC Distribution Panels	**Reduce the seismic CDF contribution from Seismic Basic Event %IE-SET36 by 90 percent.**	**NOT ESTIMATED**		**430K**	**1.2M**	**500K**
39 – Provide Procedural Guidance to Bypass Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Pressure Trip	**As provided in response to an NRC staff RAI, modify fault tree to include a new operator action, having a failure probability of 1.0E-02, representing failure of the operator to defeat the HPCI/RCIC back pressure permissive .**	**10**	**<1**	**130K**	**380K**	**120K**

Table G-6. SAMA Cost/Benefit Screening Analysis for HCGS[a] (PSEG 2009)

SAMA	Assumptions	% Risk Reduction		Total Benefit ($)		Cost ($)
		CDF	Population Dose	Baseline (Internal + External)	Baseline With Uncertainty[e]	
40 – Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive	As provided in response to an NRC staff RAI, the probability of common cause mis-calibration of all ECCS pressure transmitters was reduced to 8.0E-06 from 8.0E-05.	1	1	210K	610K	620K
41[d] – Installation of Passive Hardened Containment Ventilation Pathway	A completely passive containment vent system requiring no operator actions is assumed.	15	30	6.2M	18M	>25M
42[d] – Installation of SACS Standby Diesel-Powered Pump	Reduce the probability of initiating event %IE-SACS to 1.16E-05 per year from 1.16E-04 per year.	2	1	270K	760K	6.2M

(a) SAMAs in bold are potentially cost-beneficial.

(b) SAMA 5A added as a sensitivity case to SAMA 5 to provide a comprehensive, long term mitigation strategy for SBO scenarios.

(c) SAMAs 30, 31, and 32 were identified and evaluated in response to an NRC staff RAI (PSEG 2010a). The RAI response stated that the percent risk reduction was developed using SGS PRA Model Version 4.3 and that the implementation costs for SAMAs 30 and 31 are expected to be significantly greater than the $100K assumed in the SAMA evaluation.

(d) Value estimated by NRC staff using information provided in the ER.

(e) Using a factor of 2.5.

G.5 Cost Impacts of Candidate Plant Improvements

PSEG estimated the costs of implementing the 21 candidate SAMAs through the development of site-specific cost estimates. The cost estimates conservatively did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs for unforeseen difficulties (PSEG 2010a). The cost estimates provided in the ER did not account for inflation, which is considered another conservatism.

The NRC staff reviewed the bases for the applicant's cost estimates (presented in Table E.5-3 of Attachment E to the ER). For certain improvements, the NRC staff also compared the cost estimates to estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees' analyses of SAMAs for operating reactors.

The ER stated that plant personnel developed HCGS-specific costs to implement each of the SAMAs. The NRC staff requested more information on the process PSEG used to develop the SAMA cost estimates (NRC 2010a). PSEG responded to the RAI by explaining that the cost estimates were developed in a series of meetings involving personnel responsible for development of the SAMA analysis and the two PSEG license renewal site leads who are engineering managers each having over 25 years of plant experience, including project management, operations, plant engineering, design engineering, procedure support, simulators, and training (PSEG 2010a). During these meetings, each SAMA was validated against the plant configuration, a budget-level estimate of its implementation cost was developed, and, in some instances, lower cost approaches that would achieve the same objective were developed. The SAMA implementation costs were then reviewed by the Design Engineering Manager for both technical and cost perspectives and revised accordingly. PSEG further explained that seven general cost categories were used in development of the budget-level cost estimates: engineering, material, installation, licensing, critical path impact, simulator modification, and procedures and training. Based on the use of personnel having significant nuclear plant engineering and operating experience, the NRC staff considers the process PSEG used to develop budget-level cost estimates reasonable.

The NRC staff requested additional clarification on the estimated cost of $2.05M for implementation of SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator," and on the implementation cost of $270K for implementation of SAMA 36, "Provide Procedural Guidance for Loss of All 1E 120V AC Power," which are high for what are described as procedure changes and operator training (NRC 2010a). In response to an RAI, PSEG further described the SAMA 5 modification as providing the necessary equipment to connect a dedicated transformer at Salem Unit 3 to HCGS, which is significantly more costly than, and is in addition to, the procedure changes (PSEG 2010a). It was also explained that the SAMA 5 modification assumes that Salem Generating Station (SGS) SAMA 2 to install the dedicated transformer is already implemented and that SAMA 5 is a safety-related permanent plant modification. In response to a different RAI, PSEG explained that the SAMA 36 modification involves the development of a group of procedures, not just the revision of existing procedures or the development of a single procedure. In addition, there is a significant effort involved with determining a success path to achieve safe shutdown, to update the simulator to include all necessary components to implement the success path, to test the success path, and to implement the new procedures. Based on this additional information, the NRC staff considers the estimated cost to be reasonable and acceptable for purposes of the SAMA evaluation.

The NRC staff asked PSEG to justify the estimated cost of $100K for SAMA 10, "Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events," for what is described as including a new pump when $100K is the estimated cost of a procedure change used in the SAMA analysis (NRC 2010a). PSEG responded that the cost estimate for SAMA 10 assumes that an existing pump already installed at HCGS will be made available to implement this SAMA (PSEG 2010a). Based on this additional information, the NRC staff considers the estimated cost to be reasonable and acceptable for purposes of the SAMA evaluation.

In response to an RAI requesting a more detailed description of the changes associated with SAMA 16, "Use of Different Designs for Switchgear Room Cooling Fans," PSEG provided additional information detailing the cost estimate of this improvement (PSEG 2010a). The staff reviewed the cost estimate and found it to be reasonable, and generally consistent with estimates provided in support of other plants' analyses.

The NRC staff noted that SAMA 31, "Install Improved Fire Barriers in the Main Control Room (MCR) Control Cabinets Containing the Primary Main Steam Isolation Valve (MSIV) Control Circuits," is similar to SGS SAMAs 21 and 22 in that each involves installing fire barriers to prevent the propagation of a fire between cabinets and requested an explanation for why the estimated cost of $1.2M for SAMA 31 to modify one cabinet is similar to the estimated cost of $1.6M for SGS SAMA 22 to modify three Control Room consoles and is more than one-third of the $3.23M cost for SGS SAMA 21 to modify 48 Relay Room cabinets (NRC 2010a). PSEG responded that making the modifications to the SAMA 31 Control Room console, which is estimated to be $400K for materials and installation, is more complicated than making modifications to the SGS SAMA 21 Relay Room cabinets, which is estimated to be $35K to $70K for materials and maintenance (PSEG 2010a). Specifically, SAMA 31 requires making ventilation modifications due to the significant heat loads in addition to adding fire barrier materials. PSEG also explained that both SAMA 31 and SGS SAMA 22 assumed the same material and installation cost per console ($400K) and the same engineering cost ($800K) but that the engineering cost was evenly divided between the two units at SGS to arrive at a cost per unit. The NRC staff considers the basis for the differences in cost estimates reasonable.

The NRC staff noted that the estimated cost of $620K for SAMA 40, "Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive," is significantly higher than the estimated cost of $250K for a similar improvement evaluated for the Duane Arnold nuclear power plant license renewal application (NRC 2010a). In response to the RAI, PSEG clarified that SAMA 40 involves the installation of six key-lock switches to bypass various low pressure submissives (PSEG 2010a). Key-lock switches are used rather than jumpers, as was assumed in the Duane Arnold application, because the benefit of this SAMA cannot be obtained otherwise due to the effort required to install six jumpers, which is a more time intensive action than the time required to operate key-lock switches. Based on this additional information, the NRC staff considers the estimated cost for HCGS to be reasonable and acceptable for purposes of the SAMA evaluation.

The NRC staff also noted that the estimated cost of $1.32M each for SAMA 33, “Install Division II 480V AC Bus Cross-ties,” and SAMA 34, “Install Division I 480V AC Bus Cross-ties,” is significantly higher than the estimated cost of $328K to $656K for a similar improvement evaluated for other nuclear power plant license renewal applications, i.e., Wolf Creek and Susquehanna (NRC 2010a). In response to the RAI, PSEG described these modifications as involving the installation of new tie-breakers and cables for the 480V AC bus cross-ties, having a material and installation cost of $400K (PSEG 2010a). The most significant cost was for engineering, which was estimated to be $800K due to the electrical load analysis required to support the cross-ties. Based on this additional information, the NRC staff considers the basis for the estimated cost to be reasonable.

The NRC staff concludes that the cost estimates provided by PSEG are sufficient and appropriate for use in the SAMA evaluation.

G.6 Cost-Benefit Comparison

PSEG's cost-benefit analysis and the NRC staff’s review are described in the following sections.

G.6.1 PSEG’s Evaluation

The methodology used by PSEG was based primarily on NRC’s guidance for performing cost-benefit analysis, i.e., NUREG/BR-0184, *Regulatory Analysis Technical Evaluation Handbook* (NRC 1997a). The guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE
where
APE = present value of averted public exposure ($)
AOC = present value of averted offsite property damage costs ($)
AOE = present value of averted occupational exposure costs ($)
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($)

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. PSEG’s derivation of each of the associated costs is summarized below.

NUREG/BR-0058 has recently been revised to reflect the agency's policy on discount rates. Revision 4 of NUREG/BR-0058 states that two sets of estimates should be developed, one at 3 percent and one at 7 percent (NRC 2004). PSEG performed the SAMA analysis using the 3 percent discount rate and a sensitivity study using the 7 percent discount rate (PSEG 2009).

Averted Public Exposure (APE) Costs

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δperson-rem/year)
× monetary equivalent of unit dose ($2,000 per person-rem)
× present value conversion factor (15.04 based on a 20-year period with a 3-percent discount rate)

As stated in NUREG/BR-0184 (NRC 1997a), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk due to a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the renewal period) of the facility. Thus, it reflects the expected annual loss due to a single accident, the possibility that such an accident could occur at any time over the renewal period, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, which assumes elimination of all severe accidents, PSEG calculated an APE of approximately $688,000 for the 20-year license renewal period.

Averted Offsite Property Damage Costs (AOC)

The AOCs were calculated using the following formula:

AOC = Annual CDF reduction
x offsite economic costs associated with a severe accident (on a per-event basis)
x present value conversion factor.

This term represents the sum of the frequency-weighted offsite economic costs for each release category, as obtained for the Level 3 risk analysis. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOC of about $155,000 based on the Level 3 risk analysis. This results in a discounted value of approximately $2,332,000 for the 20-year license renewal period.

Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated using the following formula:

AOE = Annual CDF reduction
× occupational exposure per core damage event
× monetary equivalent of unit dose
× present value conversion factor

PSEG derived the values for averted occupational exposure from information provided in Section 5.7.3 of the regulatory analysis handbook (NRC 1997a). Best estimate values provided for immediate occupational dose (3,300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-year cleanup period) were used. The present value of these doses was calculated using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of $2,000 per person-rem, a real discount rate of 3 percent, and a time period of 20 years to represent the license renewal period. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an AOE of approximately $2,700 for the 20-year license renewal period (PSEG 2009).

Averted Onsite Costs

Averted onsite costs (AOSC) include averted cleanup and decontamination costs and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. PSEG derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR-0184, the regulatory analysis handbook (NRC 1997a).

PSEG divided this cost element into two parts – the onsite cleanup and decontamination cost, also commonly referred to as averted cleanup and decontamination costs (ACC), and the replacement power cost (RPC).

ACCs were calculated using the following formula:

ACC = Annual CDF reduction
x present value of cleanup costs per core damage event
× present value conversion factor

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR-0184 to be $\$1.5 \times 10^9$ (undiscounted). This value was converted to present costs over a 10-year cleanup period and integrated over the term of the proposed license extension. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an ACC of approximately $87,000 for the 20-year license renewal period.

Long-term RPCs were calculated using the following formula:

RPC = Annual CDF reduction
x present value of replacement power for a single event
× factor to account for remaining service years for which replacement power is required
× reactor power scaling factor

PSEG based its calculations on a HCGS net output of 1287 megawatt electric (MWe) and scaled up from the 910 MWe reference plant in NUREG/BR-0184 (NRC 1997a). Therefore PSEG applied a power scaling factor of 1287/910 to determine the replacement power costs. For the purposes of initial screening, which assumes elimination of all severe accidents caused by internal events, PSEG calculated an RPC of approximately $35,000 and an AOSC of approximately $122,000 for the 20-year license renewal period.

Using the above equations, PSEG estimated the total present dollar value equivalent associated with completely eliminating severe accidents from internal events at HCGS to be about $3.14M. Use of a multiplier of 6.3 to account for external events increases the value to $19.8M and represents the dollar value associated with completely eliminating all internal and external event severe accident risk for a single unit at HCGS, also referred to as the Maximum Averted Cost Risk (MACR).

PSEG's Results

If the implementation costs for a candidate SAMA exceeded the calculated benefit, the SAMA was considered not to be cost-beneficial. In the baseline analysis contained in the ER (using a 3 percent discount rate, and considering the impact of external events), PSEG identified nine potentially cost-beneficial SAMAs. PSEG performed additional analyses to evaluate the impact of parameter choices (alternative discount rates and variations in MACCS2 input parameters) and uncertainties on the results of the SAMA assessment and, as a result of this analysis, identified four additional potentially cost-beneficial SAMAs.

The potentially cost-beneficial SAMAs are:

- SAMA 1 – remove ADS Inhibit from Non-ATWS Emergency Operating Procedures
- SAMA 3 – Install Back-Up Air Compressor to Supply AOVs
- SAMA 4 – Provide Procedural Guidance to Cross-Tie RHR Trains
- SAMA 8 – Convert Selected Fire Protection Piping from Wet to Dry Pipe System
- SAMA 10 – Provide Procedural Guidance to Use B.5.b Low Pressure Pump for Non-Security Events
- SAMA 17 – Replace a Supply Fan with a Different Design in Service Water Pump Room
- SAMA 18 – Replace a Return Fan with a Different Design in Service Water Pump Room
- SAMA 30 – Provide Procedural Guidance for Partial Transfer of Control Functions from the Control Room to the Remote Shutdown Panel
- SAMA 32 – Install Additional Physical Barriers to Limit Dispersion of Fuel Oil from DG Rooms

- SAMA 35 – Relocate, Minimize, and/or Eliminate Electrical Heaters in Electrical Access Room
- SAMA 36 – Provide Procedural Guidance for Loss of All 1E 120V AC Power
- SAMA 37 – Reinforce 1E 120V AC Distribution Panels
- SAMA 39 – Provide Procedural Guidance to Bypass RCIC Turbine Exhaust Pressure Trip

PSEG indicated that they plan to further evaluate these SAMAs for possible implementation using existing HCGS Plant Heal Committee processes (PSEG 2009).

The potentially cost-beneficial SAMAs, and PSEG's plans for further evaluation of these SAMAs, are discussed in detail in Section G.6.2.

G.6.2 Review of PSEG's Cost-Benefit Evaluation

The cost-benefit analysis performed by PSEG was based primarily on NUREG/BR-0184 (NRC 1997a) and discount rate guidelines in NUREG/BR-0058 (NRC 2004) and was executed consistent with this guidance.

SAMAs identified primarily on the basis of the internal events analysis could provide benefits in certain external events, in addition to their benefits in internal events. To account for the additional benefits in external events, PSEG multiplied the internal event benefits for each internal event SAMA by a factor of 6.3, which is the ratio of the total CDF from internal and external events to the internal event CDF. As discussed in Section G.2.2, this factor was based on a seismic CDF of 1.1×10^{-6} per year, plus a fire CDF of 1.7×10^{-5} per year, plus the screening values for high winds, external flooding, transportation, detritus, and chemical release events (1×10^{-6} per year for each). The external event CDF of 2.3×10^{-5} per year is thus 5.3 times the internal events release frequency CDF of 4.4×10^{-6} per year. The total CDF is thus 6.3 $[(2.3 \times 10^{-5} + 4.4 \times 10^{-6}) / 4.4 \times 10^{-6}]$ times the internal events release frequency CDF (PSEG 2009). Seven SAMAs were determined to be cost-beneficial in PSEG's analysis (SAMAs 1, 3, 4, 10, 17, 18, and 39 as described above).

PSEG did not multiply the internal event benefits by the factor of 6.3 for eight SAMAs that specifically address fire and seismic risk (SAMAs 30, 31, 32, 33, 34, 35, 36, and 37). Multiplying the internal event benefits by 6.3 for these SAMAs would not be appropriate because these SAMAs are specific to fire or seismic risks and would not have a corresponding benefit on the risk from internal events. Two of these SAMAs were found to be cost-beneficial in PSEG's analysis (SAMAs 30 and 35, as described above).

PSEG considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. In the ER, PSEG presents the results of an uncertainty analysis of the internal events CDF which indicates that the 95th percentile value is a factor of 2.84 times the point estimate CDF for HCGS. Since the two Phase I SAMAs that were screened based on qualitative criteria were screened due to one being subsumed into another SAMA or one having already been implemented at HCGS, a re-examination of the Phase I SAMAs based on the upper bound benefits was not necessary. PSEG considered the impact on the Phase II analysis if the estimated benefits were increased by a factor of 2.84 (in addition to the multiplier of 6.3 for external events). Four additional SAMAs became cost-beneficial in PSEG's analysis (SAMAs 8, 32, 36, and 37 as described above).

PSEG provided the results of additional sensitivity analyses in the ER, including use of a 7 percent discount rate and variations in MACCS2 input parameters. These analyses did not identify any additional potentially cost-beneficial SAMAs (PSEG 2009).

PSEG indicated that the 13 potentially cost-beneficial SAMAs (SAMAs 1, 3, 4, 8, 10, 17, 18, 30, 32, 35, 36, 37, and 39) will be considered for implementation through the established HCGS Plant Health Committee process (PSEG 2009).

As indicated in Section G.3.2, in response to NRC staff RAIs, PSEG considered additional plant improvements to address basic events for which no SAMAs had been identified in the ER. PSEG determined that of the plant improvements considered, two additional SAMAs warrant further consideration: 1) SAMA 41, "Installation of Passive Hardened Containment Ventilation Pathway," and 2) SAMA 42, "Installation of SACS Standby Diesel-Powered Pump." Each of these new SAMAs is included in Table G-6 and were evaluated as described above. PSEG's analysis determined that neither of these SAMA candidates was cost-beneficial in either the baseline analysis or the uncertainty analysis.

As indicated in Section G.2.2, PSEG determined that the external events multiplier would be 6.8 if the higher seismic CDF obtained using the LLNL hazard curves were used rather than the EPRI hazard curves. As discussed in Section G.3.2, PSEG then reviewed the Level 1 and Level 2 basic events down to an RRW of 1.005 to account for the revised external events multiplier of 6.8. In addition, since the maximum benefit of each seismic sequence increased as a result of using the LLNL hazard curves, PSEG reviewed two additional seismic sequences having a benefit equal to or greater than $100,000, the minimum expected SAMA implementation cost at HCGS. These reviews resulted in the identification and evaluation of five additional SAMAs, as summarized below:

- SAMA RAI 5.j-IE1, "Install a Key Lock Switch for Bypass of the Main Steam Isolation Valve (MSIV) Low Level Isolation Logic." PSEG estimated the implementation cost for this SAMA to be the same as SAMA 40, "Increase Reliability/Install Manual Bypass of Low Pressure (LP) Permissive," or $620K, which also involved installation of key lock bypass switches (PSEG 2010a). The maximum benefit was estimated to be $110K in the baseline analysis, and $300K after accounting for uncertainties, which assumed that the risk of the basic event addressed by this SAMA was completely eliminated. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that SAMA RAI 5.j-IE1 was not cost-beneficial.

- SAMA RAI 5p-1, "Install an Independent Boron Injection System." PSEG estimated the implementation cost of this SAMA to be $1.5M based on the estimate for a similar SAMA to install a redundant system evaluated in the Browns Ferry nuclear power plant license renewal application and the estimated cost to install an additional tank (PSEG 2010a). To estimate the risk reduction, PSEG modified the HCGS PRA model fault tree to include a new basic event, having a failure probability of 1.0E-03, representing failure of the redundant system. The benefit was estimated to be $390K in the baseline analysis, and $1.1M after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that SAMA RAI 5p-1 was not cost-beneficial.

- Reinforce 1E 125V DC distribution panels 1A/B/C/D-D-417. PSEG estimated the minimum implementation cost for this SAMA to be the same as SAMA 37, "Reinforce 1E 120V AC Distribution Panels," or $500K, but expects the cost to be higher because these panels have a much higher HCLPF value than the SAMA 37 120V AC panels (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the contribution to risk from external events is approximately 5.8 times that from internal events (based on a revised seismic CDF of 3.58×10^{-6} per year using the LLNL hazard curves), that seismic events contribute 14 percent of this external events risk, and that 50 percent of the fire risk affected by the SAMA is eliminated. The benefit was estimated to be $155K in the baseline analysis, and $440K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that this SAMA was not cost-beneficial.

- Reinforce 1E 120V AC distribution panels 1A/B/C/DJ482. PSEG estimated the implementation cost for this SAMA to be the same as SAMA 37, or $500K, which also addresses 120V AC panels (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the contribution to risk from external events is approximately 5.8 times that from internal events (based on a revised seismic CDF of 3.58×10^{-6} per year using the LLNL hazard curves), that seismic events contribute 14 percent of this external events risk, and that all of the seismic risk affected by the SAMA is eliminated. The benefit was estimated to be $110K in the baseline analysis, and $320K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded that this SAMA was not cost-beneficial.

- Reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating. This SAMA assumes that 1) SAMA 37 is implemented, 2) the HCLPF values for the 120V AC panels are further increased to 1 g as a result of the implementation, 3) the above SAMA to reinforce the 125V DC panels is implemented, and 4) the HCLPF values for the panels are increased from the current 0.57g to 1.0g as a result of the implementation (PSEG

2010b). SAMA 37 originally was assumed to reduce the risk of seismic basic event %IE-SET36, "seismic-induced equipment damage state SET-36 (impacts – 120V PNL481," by 90 percent while the proposed SAMA to reinforce the 125V DC panels, by itself was originally assumed to reduce the risk of seismic basic event %IE-SET37, seismic-induced equipment damage state (impacts – 125V)," by 50 percent. The synergistic benefit of this new proposed SAMA to reinforce the 120V AC panels to a HCLPF value of 1.0g is assumed to be the sum of the benefit to eliminate the remaining 10 percent of the risk of event %IE-SET36 ($176K) and the remaining 50 percent of the risk of event %IE-SET37 ($155K), for a total benefit of $330K in the baseline analysis, and $940K after accounting for uncertainties. PSEG estimated the implementation cost for this SAMA to be $900K, which assumes the panels can be modified and not have to be replaced. Since the estimated benefit is greater than the implementation cost, PSEG determined that this proposed SAMA was potentially cost-beneficial. PSEG stated that this proposed SAMA will be considered for implementation through the established HCGS Plant Health Committee process.

The NRC staff notes that SAMA 37 was determined to be cost-beneficial and will be considered by PSEG for implementation through the established HCGS Plant Health Committee process. PSEG concluded, however, that the above originally proposed SAMA to reinforce the 125V DC panels was, by itself, not cost-beneficial, yet it was assumed to be implemented in the evaluation of this new proposed combined SAMA. Because the risk reduction from this new proposed SAMA to reinforce the 120V AC panels to a HCLPF value of 1.0g cannot be obtained without implementation of the proposed SAMA to reinforce the 125V DC panels, the NRC staff concludes that both SAMAs (SAMA 37 and the combined SAMA of reinforcing both the 120 VAC and 125 VDC panels) should be considered for implementation.

As indicated in Section G.3.2, two plant improvements were identified in the ER but not included in the SAMA evaluation because they were higher cost than the SAMA selected for evaluation. The NRC staff noted however that the two improvements could have larger benefits than the SAMAs evaluated because they could be more effective or could mitigate additional events (PSEG 2010a). In response to the RAIs, PSEG evaluated the two improvements, as summarized below:

- Replace the normally open floor and equipment drain MOVs with fail-closed AOVs. PSEG estimated the implementation cost of this SAMA to be $2.05M, which is half the estimate for a similar SAMA to replace cooling water system MOVs, which are larger than drain MOVs, with fail-closed AOVs evaluated in the TMI-1 nuclear power plant license renewal application (PSEG 2010a). To estimate the risk reduction, PSEG assumed that the entire release frequency associated with basic event CIS-DRAN-L2-OPEN, "valves open automatically for drainage normally open," after adjustment to account for existing procedures that are not credited, was eliminated. The benefit, assuming an external multiplier of 6.8, was estimated to be $710K in the baseline analysis, and $2.0M after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded the proposed improvement was not cost-beneficial.

- Auto align 480V AC portable station generator. For HCGS, this improvement is described as requiring permanent installation of an existing portable generator and adding the logic to perform the auto start and load function. PSEG estimated the implementation cost of this SAMA to be at least $1.0M based on an estimate of $1.0M from the Shearon Harris nuclear power plant license renewal application to permanently install a 480V AC generator and pump and an estimate of $3.1M from the TMI-1 nuclear power plant license renewal application to automate the start and load of an existing, permanently installed 4KV AC generator (PSEG 2010a, PSEG 2010b). To estimate the risk reduction, PSEG set the failure probabilities of existing operator actions to align the portable generator, and associated joint human error probabilities, to zero. The benefit, assuming an external multiplier of 6.8, was estimated to be $210K in the baseline analysis, and $600K after accounting for uncertainties. Since the implementation cost was greater than the estimated benefit accounting for uncertainties, PSEG concluded the proposed improvement was not cost-beneficial.

As indicated in Section G.3.2, for certain SAMAs considered in the ER, there may be alternatives that could achieve much of the risk reduction at a lower cost. The NRC staff asked the applicant to evaluate additional lower cost alternatives to the SAMAs considered in the ER, as summarized below (NRC 2010a):

- Establishing procedures for opening doors and/or using portable fans for sequences involving room cooling failures. In response to the NRC staff RAI, PSEG stated that HCGS already has procedures to implement the suggested alternative on loss of normal Switchgear Room HVAC and that this event is credited in the PRA model (PSEG 2010a). However, PSEG did provide an evaluation to implement the suggested alternative in the Service Water Pump Room, which is considered a more practical and cost effective change than SAMA 17, “Replace a Supply Fan with a Different Design in Service Water Pump Room,” and SAMA 18, “Replace a Return Fan with a Different Design in Service Water Pump Room,” which involve permanent hardware modifications. The cost of implementing an alternate room cooling strategy for this room, identified as SAMA RAI 7.a-1, was estimated to be $150K. The baseline benefit was assumed to be the sum of the estimated benefits for SAMAs 17 and 18, or $1.9M. Accounting for the revised multiplier of 6.8 and uncertainties increases the benefit to $5.9M. Since the estimated benefit is greater than the implementation cost, PSEG determined that SAMA RAI 7.a-1 was potentially cost-beneficial. PSEG also stated that this SAMA will be further evaluated in parallel with cost-beneficial SAMAs 17 and 18 since there may be some benefit associated with the permanent hardware modifications considered in these SAMAs.

- Extending the procedure for using the B.5.b low pressure pump for non-security events to include all applicable scenarios, not just SBOs. In response to the NRC staff RAI, PSEG stated that the estimated benefit for SAMA 10, "Provide Procedural Guidance to use B.5.b Low Pressure Pump for Non-Security Events," already includes the risk reduction for all applicable scenarios (PSEG 2010a). The NRC staff concludes that the suggested alternative has already been addressed.

- Utilizing a portable independently powered pump to inject into containment. In response to the NRC staff RAI, PSEG explained that the HCGS PRA model already credits use of the diesel fire pump to inject into the RPV and containment and that the addition of another independently powered pump to provide injection would have limited benefit (PSEG 2010a). PSEG further noted that SAMA 10 already evaluated aligning the B.5.b low pressure pump with RHRSW to provide al alternate source of injection. The NRC staff concludes that the suggested alternative has already been addressed.

As indicated in Section G.4, the NRC staff questioned PSEG on the risk reduction potential for certain SAMAs (NRC 2010a, NRC 2010b), as summarized below.

- For SAMA 5, "Restore AC Power with Onsite Gas Turbine Generator," PSEG provided a revised estimate of the benefit that included credit for the additional capability for mitigating a more complete set of loss of offsite power initiators that is consistent with the hardware changes proposed (PSEG 2010a, PSEG 2010b). This SAMA was determined to be potentially cost-beneficial in PSEG's revised analysis. PSEG stated that SAMA 5 will be considered for implementation through the established HCGS Plant Health Committee process.

- For SAMA 35, "Relocate, Minimize and/or Eliminate Electrical Heaters in Electrical Access Room", PSEG provided a revised estimate of the benefit assuming 99 percent of the fire risk affected by the SAMA was eliminated (PSEG 2010a). This SAMA was determined to remain cost-beneficial in PSEG's revised analysis.

The NRC staff notes that the 13 cost-beneficial SAMAs (SAMAs 1, 3, 4, 8, 10, 17, 18, 30, 32, 35, 36, 37, and 39) identified in PSEG's original baseline and uncertainty analysis, and the three SAMAs and plant improvements determined to be cost-beneficial in response to NRC staff RAIs ("establishing procedures for opening doors and/or using portable fans for sequences involving Service Water Pump Room cooling failures," SAMA 5, and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating"), are included within the set of SAMAs that PSEG plans to further consider for implementation through the established Plant Health Committee (PHC) process. The NRC staff suggests that the proposed SAMA to "reinforce the 120V DC panels" also be considered for implementation since it must be implemented to obtain the risk reduction benefits of the SAMA to "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating."

In response to an NRC staff RAI, PSEG described the PHC as being chaired by the Plant Manager and includes as members the Plant Engineering Manager and the Directors of Operations, Engineering, Maintenance, and Work Management (PSEG 2010a). The PHC is chartered with reviewing issues that require special plant management attention to ensure effective resolution and, with respect to each of the potentially cost-beneficial SAMAs, will decide on one of the following courses of actions: 1) approve for implementation, 2) conditionally approved for implementation pending the results of requested evaluations, 3) not approved for implementation, or 4) table until additional information needed to make a final decision is provided to the PHC. Additional information requested may include 1) making corrections to the original SAMA analysis, 2) examining an alternate solution, 3) performing sensitivity studies to determine the effect of implementing a sub-set of SAMAs, already approved SAMAs, or already approved non-SAMA design changes on the SAMA, or 4) coordinating the SAMA with related Mitigating System Performance Index (MSPI) margin recovery activities. If approved or conditionally approved for implementation, the SAMA will be ranked with respect to priority and assigned target years for implementation.

The NRC staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the other SAMAs evaluated would be higher than the associated benefits.

G.7 Conclusions

PSEG compiled a list of 23 SAMAs based on a review of: the most significant basic events from the plant-specific PRA and insights from the HCGS PRA group, insights from the plant-specific IPE and IPEEE, Phase II SAMAs from license renewal applications for other plants, and the generic SAMA candidates from NEI 05-01. A qualitative screening removed SAMA candidates that: (1) are not applicable to HCGS due to design differences, (2) have already been implemented at HCGS, (3) would achieve results that have already been achieved at HCGS by other means, and (4) have estimated implementation costs that would exceed the dollar value associated with completely eliminating all severe accident risk at HCGS. Based on this screening, 2 SAMAs were eliminated leaving 21 candidate SAMAs for evaluation. Nine additional SAMA candidates or plant improvements were identified and evaluated in response to NRC staff RAIs.

For the remaining 21 SAMA candidates, a more detailed design and cost estimate were developed as shown in Table G-6. The cost-benefit analyses in the ER and RAI response showed that 9 of the SAMA candidates were potentially cost-beneficial in the baseline analysis (Phase II SAMAs 1, 3, 4, 10, 17, 18, 30, 35, and 39). PSEG performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. Four additional SAMA candidates (SAMAs 8, 32, 36, and 37) were identified as potentially cost-beneficial in the ER. In response to an NRC staff RAI regarding the assumptions used to estimate the risk reduction potential of certain SAMAs, PSEG identified one additional potentially cost-beneficial SAMA (SAMA 5). In response to NRC staff RAIs regarding the seismic CDF and potential lower cost alternatives, PSEG further identified "establishing procedures for opening doors and/or using portable fans for sequences involving

Service Water Pump Room cooling failures" and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating" as being potentially cost-beneficial enhancements. PSEG has indicated that all 14 potentially cost-beneficial SAMAs, as well as the enhancements "establishing procedures for opening doors and/or using portable fans for sequences involving Service Water Pump Room cooling failures" and "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating," will be considered for implementation through the established HCGS Plant Health Committee process. In addition, it is suggested that the plant improvement to "reinforce the 120V DC panels" be included in the set of SAMAs to be considered for implementation since it must be implemented to obtain the risk reduction benefits of the plant improvement to "reinforce 1E 120V AC distribution panels to 1.0g Seismic Rating."

The NRC staff reviewed the PSEG analysis and concludes that the methods used and the implementation of those methods was sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by PSEG are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited, the likelihood of there being cost-beneficial enhancements in this area was minimized by improvements that have been realized as a result of the IPEEE process, and inclusion of a multiplier to account for external events.

The NRC staff concurs with PSEG's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of the identified, potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the NRC staff agrees that further evaluation of these SAMAs by PSEG is warranted. However, these SAMAs do not relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal pursuant to Title 10 of the *Code of Federal Regulations*, Part 54.

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10. SUPPLEMENTARY NOTES

Docket Nos. 50-272, 50-311, 50-354

11. ABSTRACT *(200 words or less)*

This draft supplemental environmental impact statement (SEIS) has been prepared in response to an application submitted by PSEG Nuclear, LLC (PSEG) to renew the operating licenses for Hope Creek Generating Station (HCGS) and Salem Nuclear Generating Station, Units 1 and 2 (Salem) for an additional 20 years. The SEIS includes the NRC staff's analysis that considers and weighs the environmental impacts of the proposed action, the environmental impacts of alternatives to the proposed action, and mitigation measures for reducing or avoiding adverse impacts. It also includes the staff's preliminary recommendation regarding the proposed action.

The NRC staff's preliminary recommendation is that the Commission determine that the adverse environmental impacts of license renewal for HCGS and Salem are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable. The recommendation is based on (1) the analysis and findings in the GEIS; (2) the Environmental Reports submitted by PSEG; (3) consultation with Federal, State, and local agencies; (4) the staff's own independent review; and (5) the staff's consideration of public comments.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	13. AVAILABILITY STATEMENT
Salem Nuclear Generating Station Hope Creek Generating Station PSEG Nuclear, LLC HCGS Supplement to the Generic Environmental Impact Statement SEIS GEIS National Environmental Policy Act NEPA License Renewal NUREG-1437, Supplement 45	unlimited 14. SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified 15. NUMBER OF PAGES 16. PRICE

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