UNITED STATES
NUCLEAR REGULATORY COMMISSION
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MEMORANDUM TO: Dr. John T. Larkins, Executive Director
Advisory Committee on Reactor Safeguards (ACRS)

FROM: Gary M. Holahan, Director
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

SUBJECT: 409TH ACRS MEETING: FOLLOWUP MATTERS

Following a meeting with the NRC staff and Mr. Donald C. Prevatte in May 1994 regarding issues related to the potential loss of spent fuel pool cooling initiated by a loss-of-coolant accident (LOCA) at Susquehanna Steam Electric Station (SSES), the Committee requested that the staff present its resolution of the issues at a subsequent committee meeting. We would like to be scheduled to present our findings during the December 1994 meeting. I have attached our draft safety evaluation regarding these issues for the Committee's scheduling consideration at the November meeting. The draft safety evaluation will also be released under separate cover letters to the Public Document Room, Mr. Donald C. Prevatte, Mr. David A. Lochbaum, and Pennsylvania Power and Light Company (the licensee for SSES).

Based on a deterministic review and a risk assessment of the postulated loss of spent fuel pool cooling scenarios at SSES, the staff has determined that the safety significance of loss of spent fuel pool cooling sequences is low. The conclusion results primarily from the low probability of the postulated initiating events and the long period of time for recovery prior to development of an environment sufficiently severe to threaten equipment operability. However, the staff did determine that modifications the licensee has made have resulted in an identifiable improvement in safety. The staff has initiated a generic review of spent fuel pool safety, which will examine the applicability of these conclusions to other light water reactor sites.

Attachment: Draft Safety Evaluation

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DRAFT (for comment)- October 24, 1994

EXECUTIVE SUMMARY

By letter dated November 27, 1992, two engineers formerly contracted with Pennsylvania Power and Light Company (PP&L) filed a report (Ref. 1) pursuant to 10 CFR Part 21 with the NRC in which the engineers described numerous potential design flaws at the Susquehanna Steam Electric Station. Reference 1 described: (1) concerns with the ability of the facility to provide adequate cooling of the spent fuel storage pool following various design basis events, (2) the potential causes and consequences of failure to cool the spent fuel storage pool based on certain known design features and certain other postulated phenomenon, and (3) numerous regulatory concerns regarding the potential design deficiencies.

The primary concern articulated by the engineers involved failure to cool the spent fuel storage pool following a design basis loss-of-coolant-accident (LOCA) or a LOCA with a loss of off-site power (LOOP). As posed by the engineers, a design basis LOCA would cause the failure of the normal, non-safety related spent fuel pool cooling system due to specific design features of the system, existing licensee procedures or due to the effects of post-LOCA environmental conditions on the non-safety related system components. The engineers further posed that a design basis LOCA results in the instantaneous development of a significant radiological source term inside the reactor building that would deny access to operators attempting to restore cooling to the spent fuel pool. The engineers did not postulate a specific sequence which would cause the source term to be present or suggest a probability for having such a source term. Rather, the engineers stated that the existence of a source term must be assumed in accordance with existing NRC regulations and guidance.

As a result of the inability to restore cooling or makeup water to the spent fuel pools, the engineers postulated that the spent fuel pool would begin to boil some time into the accident scenario. Vapor from the boiling pool would be transported throughout the reactor building by safety related ventilation systems and would eventually cause the failure of safety related systems needed to mitigate the LOCA. The report postulated that the ultimate consequences of the boiling pool would include severe core damage, failure of the stored spent fuel, and loss of primary and secondary containment with catastrophic off-site consequences.

The staff has reviewed Reference 1 and the additional correspondence supplied by the Part 21 report authors (the authors). The staff has evaluated the safety significance of the issues identified in the report. In addition, the staff has evaluated those issues which were identified as compliance or regulatory in nature. The staff's safety evaluation, which stands separate from its regulatory compliance evaluation, examined the specific scenarios and technical issues identified in the report, including the specific sequence or sequences needed to achieve the postulated consequences. The attached safety analysis includes a review of certain specific aspects of the facility design and a deterministic examination of some of the physical phenomena involved.

The evaluation also includes a probabilistic analysis of postulated event sequences involving loss of spent fuel storage pool cooling.

Based on a deterministic analysis of the plant as it is currently configured, considering recent plant modifications and procedural improvements, the staff concludes that systems used to cool the spent fuel storage pool are adequate to prevent unacceptable challenges to safety related systems needed to protect the health and safety of the public during design basis accidents.

The probabilistic review determined that the specific scenario originally described by the report authors is a very low probability sequence. The overall low probability of the Part 21 report scenario was driven by the low probability of LOCA sequences that incurred severe early core damage that would pose a threat to operator access to the reactor building. However, the staff did not limit the probabilistic analysis to the specific Part 21 report scenario. The staff recognized that numerous other initiating events had the potential to cause a loss of spent fuel pool cooling, and the staff examined the risk associated with these initiating events, which included seismic events, loss of off-site power events, and flooding events. The staff also recognized that the failure mechanisms by which the operators would be unable to provide cooling to the spent fuel pool were not limited to operator access considerations. Thus, the staff also modeled LOCA sequences leading to spent fuel pool boiling that did not consider operator access restrictions. The staff concluded that, even with consideration of the additional initiating events, loss of spent fuel pool cooling events presented a challenge of low safety significance to the plant.

During the course of the staff review, the licensee completed several modifications to the facility, including removal of the gates that separate the spent fuel storage pools from the common cask storage pit, administrative controls to ensure pool boiling will not occur for at least 25 hours following a loss of cooling, installation of remote spent fuel pool temperature and level indication in the control room, and numerous procedural upgrades. However, the licensee's proposal to credit the spent fuel pool cooling assist mode of RHR as the design and licensing basis means of spent fuel pool cooling following a seismic event remains open pending staff review and confirmation that the operation and design of the spent fuel pool cooling assist mode of RHR is consistent with this purpose.

The staff evaluated the relative safety of the author's concerns with respect to the configuration of the Susquehanna facility as it existed at the time of the Part 21 report and as it exists at the present time. Despite the overall low safety significance of loss of pool cooling events, the staff concluded that the plant modifications and procedural upgrades provided an identifiable improvement in plant safety. Additionally, the staff has initiated an effort to examine certain issues related to spent fuel pool cooling reliability in greater detail on a generic basis.

1.0 INTRODUCTION

By letter dated November 27, 1992 (Ref. 1), two contract engineers (the authors) working for Pennsylvania Power and Light Company (PP&L or the licensee) filed a report (Ref. 1) with the NRC pursuant to 10 CFR Part 21. Reference 1 detailed potential weaknesses in the design of systems used to cool the spent fuel storage pool at the Susquehanna Steam Electric Station (SSES), Units 1 and 2, that the authors contend would result in cascading failures of systems as a direct, mechanistic result of a design basis event. Reference 1, which consisted primarily of a compilation of internal memoranda between the authors and the licensee and internal licensee documents, provided a technical description of the potential design weaknesses as well as analyses of the regulatory requirements for the relevant issues.

The contract engineers concluded that a loss of coolant accident (LOCA) or a LOCA with a concurrent loss of off-site power (LOOP) would directly cause the loss of the normal spent fuel pool cooling system for the affected unit(s). A LOCA may initiate the auxiliary load shed feature at SSES that automatically results in a loss of the spent fuel pool cooling function, and the spent fuel pool cooling system is not designed to operate during a LOOP. The authors also contended that the normal spent fuel pool cooling system is not designed to withstand the radiation level, temperature, and humidity developed within the reactor building by the LOCA, and they contended that, as a consequence of these conditions, the spent fuel pool cooling system would be expected to fail at some point following the accident. Finally, the authors noted that, unlike safety-related systems, the normal spent fuel pool cooling system was not qualified to seismic Category I standards and was not designed to retain its function following a single active failure.

The authors also contended that, prior to the authors filing of Reference 1, the licensee did not have adequate provisions in place to ensure that alternate cooling methods could be successfully established. The primary means of alternate spent fuel pool cooling is the spent fuel cooling assist mode of the residual heat removal (RHR) system. Based on documents included within Reference 1, the authors questioned the capability of the RHR system to adequately perform this function.

Assuming that the spent fuel pool cooling function is capable of being restored from an equipment standpoint, the authors contended that operators would be unable to access the necessary equipment within the reactor building to restore the function. This contention is based on the radiological dose calculated to result from the application of design basis radionuclide release assumptions described in Regulatory Guide 1.3 (Ref. 2) to the LOCA. The authors contend that this release assumption must be applied in evaluating all aspects of the event.

As a result of the inability to restore cooling to the spent fuel pools, the engineers postulated that the spent fuel pool would begin to boil some time into the accident scenario. Vapor from the boiling pool would be transported throughout the reactor building by safety related ventilation systems and would eventually cause the failure of safety related systems needed to

mitigate the LOCA and protect fission product barriers. Reference 1 described a scenario where sustained boiling of the spent fuel pool would cause catastrophic off-site consequences as a result of the severe core damage, failure of the stored spent fuel, and loss of primary and secondary containment. The authors further concluded that the perceived deficiencies affected systems and events that were within the design and licensing basis of the facility.

The NRC staff has had numerous interactions with the authors and the licensee since the filing of Reference 1, including written correspondence and public meetings. Subsequent to a public meeting on October 1, 1993 between the staff and the authors, the staff developed an action plan for the systematic evaluation and resolution of the issues raised in Reference 1 and subsequent correspondence. The action plan identified specific technical subjects for which the potential safety significance was to be evaluated. The plan also identified the need to evaluate specific regulatory and licensing issues. Finally, the plan noted, in general terms, the need to evaluate the significance of the spent fuel pool cooling issues raised in Reference 1 on a generic basis.

This safety evaluation (SE) documents the staff's review of the safety significance of the issues identified in Reference 1 as they pertain to SSES. Section 2.0 of the report provides a description of the relevant system hardware and the failures of those systems postulated in Reference 1. Although the staff's review of related licensing issues was partially documented in a letter to the authors dated March 16, 1994 (Ref. 3), additional information on licensing and regulatory issues is also documented in Section 3.0 and Appendix A of this report. Section 4.0 examines specific hardware and procedural issues in detail and treats them in a deterministic fashion. These deterministic analyses are used to close certain specific issues raised in Reference 1. They are also used to provide a foundation for certain assumptions in the probabilistic risk analysis described in Section 5.0 of the SE. Section 5.0 describes the probabilistic risk model used to evaluate the safety significance of spent fuel pool boiling events at SSES. The staff examined the risk associated with the scenarios and sequences postulated in Reference 1. In addition, the staff examined a broad range of events that could lead to boiling in the spent fuel pool and the subsequent consequences. Section 6.0 of the SE provides a discussion of radiological issues. The staff's overall conclusions are documented in Section 7.0

As a result of the examination of the issues described in Reference 1 as they pertained to the SSES facility, the staff has developed a task action plan to examine certain specific issues in more detail on a generic basis. The staff's generic action plan was provided to the public document room by letter dated Xxxxxxx XX, 1994 (Ref. 4). The results of the staff's generic review will be documented separately as provided for in the generic action plan.

2.0 SYSTEM DESCRIPTIONS

The system descriptions provided here are limited to those systems that significantly affect the capability of SSES to mitigate a loss of SFP cooling event. The degree of detail varies based on the relevance of the system to staff conclusions.

2.1 Spent Fuel Pool Configuration

The two BWR 4 reactors with Mark II pressure suppression containments at SSES share a common refueling floor that spans the entire top level of the two reactor buildings at the 818' elevation. The two SFPs are centrally located between the two reactors on the refueling floor and share a common cask storage pit.

Gates normally separate each SFP from the associated reactor cavity and formerly separated each SFP from the common cask storage pit. During refueling activities, the reactor cavity is flooded, and the gates between the reactor cavity and the associated SFP are removed to allow fuel transfer. Removal of the two gates isolating the cask storage pit allows free communication between the two SFPs. Gate removal requires use of the refueling floor overhead crane, which is supplied by an off-site source of electrical power. Cooling systems connected to the adjacent pools (the other SFP or the reactor cavity) become available to cool both SFPs when the gates between the pools are removed. The greater communicating volume of water resulting from removal of a gate increases the heat addition necessary to raise the water temperature a given amount, thereby increasing the time to boil.

By letter dated June 1, 1994 (Ref. 5), the licensee committed to operating the plant with the cask storage pit gates removed except during infrequent periods involving cask pit operations. The staff has considered the impact of this modification in this evaluation.

Each SFP has an associated skimmer surge tank. The skimmer surge tanks provide a reserve volume of water to accommodate transients in cooling system flow and ensure adequate net positive suction head for the spent fuel pool cooling system (SFPCS) pumps. The skimmer surge tanks are connected by weirs to the associated SFP and the common cask storage pit, and the skimmer surge tanks also collect water from the wave scuppers around the associated SFP.

The licensee has recently installed additional spent fuel pool level and temperature instrumentation. The new instrumentation provides continuous temperature and level indication on control room panel 1C644. The level indication has a 28 inch range spanning elevations 815' 9" to 818' 1". The staff confirmed that the top of the weir to the associated skimmer surge tank is at the 817' 1/2" elevation, and the range of the level instrumentation encompasses the level necessary for initiation of the SFP cooling assist mode of the RHR system and the minimum level required by SSES Technical Specifications. Licensee supplied documents indicate the temperature instrument has a range of 50°F to 220°F.

The level and temperature instrumentation is not safety-grade. The instrumentation is not Class 1E, but it is powered from Class 1E panel 1Y226 with appropriate Class 1E isolation devices. The new elements and instrumentation are seismically/dynamically mounted for the protection of nearby safety related equipment.

2.2 Spent Fuel Pool Cooling and Cleanup System

A separate spent fuel pool cooling system is provided for each spent fuel pool. The spent fuel pool cooling and cleanup system is not safety-related, and the system piping is not designed to seismic Category I standards. Also, because the SFPCS pumps are not connected to the Class-1E emergency buses that receive backup power from the emergency diesel generators (EDGs), a loss of off-site power causes a failure of the SFPCS. In addition, a single failure in the SFPCS instrumentation associated with the common low skimmer surge tank level trip of operating SFPCS pumps taking suction on the affected surge tank can cause a total loss of SFPCS flow for one SFP.

The SFPCS associated with each SFP consists of three parallel heat exchangers and three pumps. Water from the skimmer surge tanks flows through a common header to the parallel heat exchangers. The outlet piping from the heat exchangers ties into a common header that serves the parallel pumps, which then discharge into another common header. A portion of the pump discharge is piped to one of the three filter demineralizers within the cleanup subsystem, which is shared by the two SFPs. The remainder of the flow bypasses the demineralizers. The demineralizer flow and bypass flow combine into a common header before returning to the spent fuel pool.

The SFPCS pumps and heat exchangers for each unit are located in a common equipment room on the 749' elevation. Equipment used in routine operation of the system includes: 1) the Fuel Pool Cooling Panel 1(2)C206 located on the 749' elevation; 2) Fuel Pool Demineralizer Bypass Valve 153013 (253013), which is located on the 749' elevation for Unit 1 and on platform elevation 762'-10" for Unit 2; 3) the Fuel Pool Storage Control Panel OC211 located on the refueling floor and 4) the Fuel Pool Filter Demineralizers Control Panel located on the 779' elevation.

The SFPCS is provided with certain instrumentation and controls. The skimmer surge tank is equipped with a single level transmitter that provides level indication on panel 1(2)C206, high and low level alarms on panels 1(2)C206 and OC211, and a low surge tank level trip of the operating SFPCS pumps. Each pump is equipped with a pressure switch at the pump suction and a pressure transmitter at the pump discharge which provides pump discharge pressure indication on panel 1(2)C206. A flow transmitter and pressure transmitter are provided on the common pump discharge header. Flow indication is provided on panel 1(2)C206 and low flow alarms are provided on panels 1(2)C206 and OC211. A low discharge pressure alarm is provided on panels 1(2)C206. Temperature elements and high temperature alarms are associated with the spent SFPCS heat exchangers and additional flow elements and indication are associated with the filter demineralizer bypass line. The instrumentation and controls for the system are not maintained within the equipment qualification program for Susquehanna.

2.3 Normal Service Water System

The SFPCS heat exchangers reject the SFP decay heat to the normal service water system (SWS). At the design SFP heat load of 12.6×10^6 BTU/hr and the design SWS inlet temperature of 95°F, the SFPCS is designed to maintain the SFP below 125°F. At lower SWS temperatures, the SFP can be maintained at less than 125°F with larger than design heat loads in the SFP.

The SWS at SSES is not a safety-related system. Consequently, a single failure that causes a loss of SWS flow to the heat exchangers results in a loss of the SFP decay heat removal function. In addition, the SWS piping is not qualified to seismic Category I standards, and the SWS pumps are not provided with backup power from the EDGs.

Each unit at SSES is provided with a separate SWS. Each SWS operates in a single loop serving heat exchangers throughout the unit. The three 50 percent capacity service water pumps per loop draw water from the respective cooling tower basin, circulate water through the unit, and return the water to the cooling tower.

The breakers supplying power to the SWS pumps from the 13.8 kV switchgear are opened by an auxiliary load shed feature included in the original design of SSES. The auxiliary load shed is initiated on the accident unit's switchgear by a LOCA signal (high drywell pressure or low reactor vessel level) in conjunction with a generator lockout, which is initiated by reverse power relays. The generator lockout would typically result from the reactor trip/turbine trip from high power levels initiated by a LOCA signal, but it is also generated by other events. The load shed ensures that sufficient voltage from the off-site power source is available to support starting of the major safety-related systems.

By letter dated May 5, 1994 (Ref. 6), the licensee corrected a description of the auxiliary load shed feature that had been provided in a letter dated May 24, 1993 (Ref. 7). In Reference 6, the licensee described the load shed of the affected unit's service water pump as causing the loss of the spent fuel pool cooling function. With the exception of venting the SFPCS heat exchangers and the reactor building chillers to restore the full design capability of these components, recovery of the SWS can be performed outside of the reactor building. Based on the configuration of the SFPCS heat exchangers, the NRC staff concluded that the heat exchangers would regain significant heat transfer capability following restoration of SWS flow without venting.

2.4 Spent Fuel Pool Cooling Mode of the Residual Heat Removal System

The residual heat removal (RHR) system consists of two full capacity loops. Each loop contains two RHR pumps and one RHR heat exchanger. The RHR heat exchanger transfers heat from the fluid in the RHR system to the residual heat removal service water (RHRSW) system, which then rejects the heat to the ultimate heat sink (UHS). At SSES, the UHS is a spray pond with redundant spray loops.

The RHR system is capable of being aligned to cool the SFP. The SFP cooling assist mode of RHR was designed to provide supplementary SFP cooling when the heat load in the SFP exceeds the capacity of the SFPCS. This condition may occur during a full core off-load to the SFP shortly after shutdown of the reactor. Because the RHR system and the associated RHR service water system are designed to perform their safety functions when off-site power is unavailable and with a single failure of an active component, these systems may be available for SFP cooling when the SFPCS is inoperable.

In the SFP cooling assist mode of RHR system operation, water from the SFP skimmer surge tank flows to the suction of one of the four RHR pumps. From the discharge of the RHR pump, the water flows through one of the RHR heat exchangers and returns to the SFP. The SFP cooling mode of RHR shares only a small section of the suction piping from the skimmer surge tank with the SFPCS, and all piping associated with the SFP cooling mode of RHR is constructed to seismic Category I standards, including the attached portion of the SFPCS piping up to the first isolation valve.

There are several design features that affect the SFP cooling assist mode of RHR system with regard to redundancy. For example, failure to open any one of several manually operated valves in the flow path would prevent operation of the RHR system in this mode. Also, sections of the piping used for the SFP cooling assist mode and the shutdown cooling mode of RHR system operation are shared, which prevents simultaneous operation of separate loops of the RHR system in these two modes on one unit, despite the provision of some redundant components. For similar reasons, the use of a "B" loop RHR pump in the SFP cooling assist mode prevents use of the "A" loop of RHR for any other function because only the "A" loop piping is configured to return water to the SFP. Therefore, the loop cross-connect must be opened to allow the "B" loop of RHR to return water to the SFP, and the discharge piping of both loops are configured to direct the discharge to the SFP. However, with the "A" loop of RHR in the SFP cooling assist mode, the "B" loop of RHR may be operated to perform safety functions such as core injection and suppression pool cooling, but not shutdown cooling.

2.5 Residual Heat Removal Service Water System

The RHRSW system has the safety function of transferring heat from the RHR system via the RHR heat exchangers to the ultimate heat sink. The RHRSW system is designed to provide a reliable source of cooling water for all operating modes of the RHR system under design basis conditions. To satisfy this design requirement, the RHRSW system is designed to operate following a loss of off-site power, and it is designed to seismic Category I standards.

Each unit is provided with two loops of RHRSW, the "A" loop and the "B" loop. Each loop has a 100 percent capacity, vertical turbine type two stage pump that draws water from the spray pond. Each loop can be cross-connected to supply the corresponding loop in the opposite unit.

The RHRSW system return can be aligned to the spray pond from the control room via any of the following paths: the normally open spray bypass line, the normally isolated large spray network, or the normally isolated small spray network. The spray bypass line returns the water directly to the spray pond without cooling. The spray networks reject heat to the atmosphere by evaporation from and sensible cooling of the water spray.

2.6 Spent Fuel Pool Make-up from the Essential Service Water System

The safety-related essential service water (ESW) system provides redundant paths for makeup water addition through seismic Category I piping from the UHS to each of the SFPs. Section 9.1.3 of the SSES Final Safety Analysis Report (FSAR) (Ref. 8) states that the design makeup rate is based on replenishing the rate of water loss due to boiling assuming the maximum normal decay heat rate for each SFP. Table 9.2-3 of Reference 8 lists the design makeup rate for each ESW loop to each pool as 60 gpm.

The alignment of the ESW system to provide makeup to the SFPs involves the manipulation of three 2" manual valves per ESW loop in two different areas of the plant. With an ESW loop in operation, opening a single valve at the 670' elevation in unit 1 (683' elevation of unit 2) ties the respective SFP make-up line to the ESW loop. Two ESW valves in each SFP make-up line are located inside the SFPCS equipment room at the 749' elevation (in both units) and are used to control make-up flow to the SFP.

Because both skimmer surge tanks are connected by weirs to the cask storage pit and their associated SFP, makeup water addition to one SFP can be used to raise level in the other SFP, even when both gates between the pools are installed. Once water level is above the weir in one SFP, the overflow from the full SFP will fill, in succession, the associated skimmer surge tank, the cask storage pit, the other skimmer surge tank, and the other SFP. An unisolable rupture in the seismic Category I piping attached to either skimmer surge tank, which has an extremely low probability of occurrence, would prevent this method from successfully transferring make-up water between pools.

2.7 Ventilation Systems

The SSES secondary containment is divided into three separate ventilation zones. Zones I and II surround the respective Unit 1 and Unit 2 primary containments below the floor at elevation 779'-1". Zones I and II also include stairwells and elevator shafts above that elevation. Zone III consists of the remaining portions of secondary containment above the floor at elevation 779'-1" including the refueling floor. Zone III also includes the railroad access shaft and the railroad bay within the Unit 1 reactor building. The electrical equipment rooms and heating and ventilation equipment rooms within the reactor buildings are not contained within secondary containment. These rooms are separated from secondary containment by air locks. However, the safety-related load center rooms are located within Zone I and Zone II, and the safety-related control structure chilled water system cools the air supplied to the load center rooms from the reactor building general area. Dedicated recirculating coolers, which are supplied with cooling water from the ESW system, provide cooling to other essential components. Access to any ventilation zone from outside the secondary containment boundary or from another ventilation zone is through air locks with air-tight doors on both

sides.

2.7.1 Normal Ventilation Systems

Each of the ventilation zones is provided with independent heating, ventilating and air conditioning (HVAC) systems designed to operate during normal plant operation and during shutdown periods. Zone III systems function during normal fuel handling and storage operations.

The portion of the reactor building HVAC system ductwork associated with the recirculation system is safety-related. The remaining portion of the ductwork within the secondary containment boundary is not safety-related. Each zone is provided with a separate supply subsystem supplying 100 percent conditioned outside air, an exhaust subsystem connecting to the reactor building exhaust vent, and a filtered exhaust system for areas with higher potential for radioactive contamination. Redundant secondary containment isolation dampers are installed in series to ensure isolation of ductwork penetrating the secondary containment boundary.

2.7.2 Safety-Related Ventilation Systems

The standby gas treatment system (SGTS) and the recirculation system constitute the safety-related ventilation systems for the SSES reactor buildings. The SGTS is designed to maintain the affected zones of secondary containment at approximately a 0.25 in. wg. negative pressure and control the cleanup of airborne radioactivity from within secondary containment prior to release to the environment for certain design basis events. The recirculation system is designed to mix and dilute airborne radioactivity and control the spread of airborne radioactivity to other areas following certain design basis events.

A reactor building zone isolation signal causes realignment of the ventilation systems from the normal systems to the safety-related systems. The reactor building zone isolation signal causes the following automatic sequence of events to occur within the affected zone or zones: secures all fans in the normal ventilation systems; closes normally open redundant isolation dampers (two in series to isolate the non-safety-related portions from safety-related portions of each system); opens normally closed isolation dampers (two in parallel to connect the recirculation fans and plenum with the safety-related recirculation ductwork); and starts the recirculation system fans and the SGTS. The following events are designed to initiate reactor building zone isolation: high radiation level in refueling floor or railroad access shaft exhaust; high drywell pressure or low reactor vessel water level (LOCA signals); a LOOP (generates false LOCA signals in each unit); and a manual signal from the control room. The high radiation signals isolate Zone III only. However, the LOCA signals isolate the affected unit zone and Zone III. The LOOP generates two false LOCA signals that result in isolation of all three zones. The manual signal can be used to isolate Zone III only, or either Zone I or Zone II with Zone III.

The recirculation plenum is divided into a return plenum and a supply plenum. Redundant, parallel recirculation fans draw air from the return plenum and

supply air directly to the supply plenum. Zone III is continuously aligned to the return and supply plenums. However, redundant, parallel dampers normally isolate the Zone I and Zone II normal ventilation systems from the return plenum. Similarly, redundant, parallel dampers normally isolate the supply plenum from the Zone I and Zone II normal ventilation systems. The recirculation system fans circulate air from the supply plenum through distribution ductwork to the aligned zone(s) and draw air back from the aligned zones through separate ductwork to the return plenum.

Redundant, parallel dampers also isolate the inlet to the SGTS from the supply plenum. When aligned and operating, the SGTS fans draw air from the supply plenum through ductwork, which passes through the unit 1 reactor building, to the control structure. The SGTS ductwork divides to pass through redundant, parallel fire protection dampers at the interface between structures. Inside the control structure, outside air is provided through redundant, parallel dampers to supplement flow from within secondary containment. The additional air supply satisfies the SGTS fan minimum flow requirement of 3000 cfm when secondary containment leakage is low.

Each redundant SGTS train has a controllable capacity from 3000 cfm to 10,500 cfm. Redundant, parallel filter trains remove radioactivity prior to the air passing through the SGTS fans to the SGTS exhaust vent. The filter trains consist of the following components in series: a mist eliminator; a heater bank; a pre-filter; an upstream HEPA filter; a set of charcoal adsorber beds; and a downstream HEPA filter. Although a heater bank capacity of approximately 70 kW is adequate to reduce the humidity of the inlet airstream at the maximum design inlet temperature of 125°F from 100 percent to 70 percent, a 90 Kw heater is provided. The 90 Kw heater size was based on the capacity necessary to reduce the humidity of an inlet airstream at 180°F from 100 percent to 70 percent. However, this original heater sizing calculation modeled the heat loss from the airstream between the heater bank and the charcoal adsorber differently than the later calculation. Therefore, the results of the calculations are not directly comparable.

2.8 Reactor Building Drain System

The various waste collection points within the reactor building, excluding those inside the drywell, drain by gravity to the reactor building sumps, which are located at the lowest elevation in the reactor building. The drain system was sized to accommodate a 5 minute actuation of fire protection systems. Each reactor building sump is equipped with two sump pumps, which are not supplied from an emergency electrical bus. With off-site power available, the sump pumps start automatically when a predetermined high level is reached in the sump, and the pumps automatically stop at a predetermined low water level. The potentially radioactive waste water collected in the reactor building sumps is pumped to waste collection tanks in the radwaste building.

Each of the six pump rooms in each reactor building basement (emergency core cooling system and reactor core isolation cooling system pump rooms) is provided with a separate drain line to the reactor building sump inlet header. A normally closed manual valve is provided in each drain line outside the pump room to prevent flooding of the pump rooms by back-flow. Safety-grade seismic Category I instrumentation provides control room alarms if the water level in any pump room exceeds a preset level.

3.0 Licensing and Design Basis Issues

Based on a review of the licensing basis of the SSES facility as it pertains to the issues in the Reference 1, the staff concluded that a link between loss of SFP cooling events and design basis loss of coolant accidents (LOCA) and/or loss of off-site power (LOOP) events postulated by the authors of the Part 21 report could not be considered within the original licensing basis of the Susquehanna facility. As a result, the staff determined that the issues described in Reference 1 did not represent compliance issues as that term applies to 10 CFR Part 50.109, "Backfitting". Rather, the staff concluded that the evaluation of the potential safety significance of the LOCA/boiling SFP issues must be conducted to determine whether any changes to the facility were necessary for the continued assurance of no undue risk to the public health and safety or whether any safety enhancements, providing significant safety benefit at a justifiable cost, were warranted. A comprehensive review of licensing basis issues is contained in Appendix A.

4.0 DETERMINISTIC ANALYSES

The staff has pursued deterministic analyses where the results could be applied meaningfully. In particular, the staff intended the analyses to verify critical assumptions in the risk assessment and to evaluate technical issues documented Reference 1.

4.1 Spent Fuel Pool Configuration

The configuration of the SFP affects the availability of SFP cooling and the time available to align a method of cooling prior to the onset of SFP boiling. By allowing free communication of water between the two SFPs, cooling systems associated with either unit may be used to provide cooling. Also, for a given heat load and initial temperature, the time available prior to the onset of boiling increases proportionately with the volume of coolant.

4.1.1 Cooling Capability with SFPs Connected via the Cask Storage Pit

The risk assessment conservatively modeled the natural circulation cooling of a SFP with no operable cooling system by a SFP cooling system associated with the adjacent SFP. The risk assessment defined a SFP outlet temperature of 170°F as the maximum allowable temperature prior to reaching a near boiling condition. This maximum temperature is based on maintaining both SFPs below bulk boiling conditions with the SFPs cross-connected via the cask storage pit and only one SFP being actively cooled.

In several submittals, PP&L stated that a cooling system operating in one SFP adequately cools an adjacent SFP with no operable cooling system by natural circulation through the cask storage pit with the gates removed. In Reference 6, PP&L clarified this statement by describing that this conclusion was based on test results. In Reference 5, PP&L committed to normally operate with gates between the SFP and the cask storage pit removed, but the change does not preclude installation of the gates for specific, infrequent evolutions after that date. This change was scheduled to be effective by June 30, 1994, and NRC inspector verification of the necessary procedural changes is documented in NRC inspection report 50-387/94-xx and 50-388/94-xx (Ref. 9).

The test procedure used to demonstrate adequate cooling, TP-135(235)-011, Revision 0, "Fuel Pool Decay Heat Removal," is performed at each refueling outage to monitor SFP temperature and heat load for SWS outages. The NRC staff reviewed TP-235-011, Revision 0, approved September 25, 1992, including a change regarding administrative SFP temperature limits, which was approved on April 7, 1994. This procedure isolates SWS flow to the outage unit's SFPCS heat exchangers, but maintains the outage unit's SFPCS pumps in operation. Therefore, although no cooling is provided by the outage unit's SFPCS, it will aid in mixing the outage unit's SFP.

The data collected from these tests during the past three refueling outages indicates that the temperature difference between the SFPs can be maintained less than 1°F with a heat load of approximately 20×10^6 BTU/hr in the outage unit's SFP. The SFP temperatures are measured using a single resistance temperature detector (RTD) in each pool. Because the RTD probes are located in similar positions near the pool surface, similar temperatures indicate substantial mass transfer from the warmer pool to the cooler pool within the upper levels of the pool. A counter-acting flow of water from the cooler pool to the warmer pool occurs at an elevation near the bottom of the cask pit gate opening, which is approximately one foot above the top of the fuel.

The staff does not expect the absence of operating SFPCS pumps or a change in the decay heat rate within the SFP without an operable SFPCS to significantly change the conclusion of adequate mixing. Mixing of the SFP coolant is inherent in the design of the spent fuel assemblies and the placement of the fuel assemblies within the SFP. This conclusion is supported by analytical results documented in NUREG/CR-5048 (Ref. 10).

The above information describes a mechanism that ensures adequate thermal mixing will occur between interconnected pools to assure that only a minor temperature difference will exist between the bulk temperatures of the two pools. Therefore, the staff concluded that a single operating cooling system with adequate capacity will ensure that neither SFP has reached boiling conditions when the SFPs are cross-connected.

4.1.2 Time to Boil Considerations

The risk assessment model used an estimated range of times to reach a near boiling condition (170°F in the cooler of two cross-connected pools or 200°F in an isolated pool) from an initial SFP temperature at the administrative limit of 115°F. The times to reach near boiling at various phases in the operating cycle were based on the decay heat rate assuming a full-core offload with one-third core replacement each refueling outage and the minimum volume of coolant associated with the necessary SFP configuration in that phase of the operating cycle. Regardless of the assumed configuration, the estimated time to reach near boiling was less than 50 hours only for periods between the core offload and core reload during a refueling outage.

The licensee calculated SFP decay heat rates assuming operation for a full 18 month cycle at the uprated power level. Table 9.1-2e and Table 9.1-2f of Reference 8 present the updated design basis results. For a normal discharge of one-third core that completely fills the SFP after a series of one-third core discharges, PP&L calculated a decay heat rate of 16.2×10^6 BTU/hr at 144 hours following shutdown. In addition, PP&L calculated a decay heat rate of 33.9×10^6 BTU/hr at 250 hours following shutdown for a full core off-load that completely fills the spent fuel storage racks after a series of one-third core discharges at 18 month intervals. These decay heat rate values are intended to bound the decay heat rate for any realistic set of fuel discharges. The staff found these values acceptable.

In a typical refueling outage as described in a letter dated August 16, 1993 (Ref. 11), PP&L normally off-loads the entire core with the reactor well and equipment pit communicating freely with the SFPs. The fuel off-load typically starts on day 6 (6 days after shutdown) and is completed by day 13. The typical pool configuration (2 fuel pools + cask storage pit + reactor well + equipment pit) provides the outage unit with a large effective pool volume. This configuration is maintained typically until reactor vessel reload is

completed on about day 37 of the outage.

During the off-load, the outage unit RHR system is typically operated in the shutdown cooling mode until fuel off-load is completed. After the off-load, one loop of the outage unit RHR system will typically be available until maintenance on the common portions of the RHR system is performed. For the 7th refueling outage of SSES Unit 1, the maintenance on the common portions of the RHR system was scheduled to occur between day 16 and day 26 of the outage. During the period that common portions of the RHR system were unavailable, the time for the SFP to boil varied from 40 to 49 hours, assuming an initial SFP temperature of 110°F. The NRC staff concluded that the estimated time to boil is sufficiently long to justify assuming a high probability of restoring RHR following a loss of the SFPCS prior to the onset of boiling. Although the shutdown cooling mode may not provide adequate SFP cooling alone due to stratification, a portion of the shutdown cooling return flow may be diverted to the SFP to provide cooling when the reactor cavity is connected to the SFP.

During the period that the outage unit's core is resident in the outage unit's SFP, the operating unit's SFPCS is typically used for decay heat removal. PP&L generally maintains the outage unit's SFPCS available for several days to ensure the operating unit's SFPCS has adequate heat removal capability before the outage unit's SWS is removed from service. Although the decay heat rate of the combined SFPs may exceed the design heat removal capacity of a single unit's SFPCS during this period, PP&L has generally used the additional heat removal capability provided by SWS supply temperatures below the design value to allow the outage unit's SFPCS to be removed from service for maintenance.

About day 30, the RHR system is typically returned to service in the shutdown cooling mode as core reload begins. About day 37, fuel reload will generally be completed. Then SFPs will be typically isolated from the reactor cavity by day 39. At this time, the outage unit's fuel pool time to boil with the cask pit gates installed is approximately 50 hours, even though the pool volume is significantly smaller than it was during the outage. This is because the resident fuel bundles have had additional time to decay and only 1/3 of the off-loaded core remains in the SFP.

In addition to the typical refueling outage practice/sequence, the licensee has provided the decay heat generation rate, effective fuel pool volume and time for the SFP to boil at various stages of a typical refueling outage for staff review. The calculated time to reach boiling in the SFP provided by PP&L exceeds 25 hours at all times during a typical outage after achieving the full core off-load at 13 days post-shutdown. This is consistent with Section 9.1.3 of Reference 8 and Appendix 9A to Reference 8, which state that the time to reach boiling will exceed 25 hours following a loss of SFP cooling. However, an NRC staff audit of outage management procedures at PP&L headquarters determined that no procedural controls were in place to control the time to reach boiling in the SSES SFPs. In Reference 5, PP&L committed to address this omission by incorporating into appropriate procedures necessary measures to assure the minimum 25 hour time to boil is maintained throughout the outage by June 30, 1994. NRC inspector verification of the necessary procedural changes is documented in Reference 9.

During the review, the NRC staff performed independent analyses to verify the decay heat generation rates and pool boiling times calculated by PP&L. The NRC staff concluded that the results calculated by PP&L are conservative.

4.1.3 Conclusions Regarding the Spent Fuel Pools

Based on a review of the configuration of the SFPs and anticipated decay heat rates originating from the stored fuel, the staff concluded that several methods and long periods of time are available to recover from a loss of SFP cooling. Test results and analytical studies support the conclusion that significant natural circulation flows develop between the SFPs at SSES via the cask pit when the pools are cross-connected. Therefore, cooling systems associated with either SFP may be used to cool the both SFPs in the cross-connected configuration. Additionally, PP&L's commitment to incorporate into appropriate outage management procedures measures to assure the minimum time to the onset of pool boiling exceeds 25 hours ensures a significant time is available to restore SFP cooling.

4.2 Normal Spent Fuel Pool Cooling System Operation

At SSES, the SFPCS is not a safety-related system. Consequently, the SFPCS components have not been analyzed or tested to demonstrate a high probability of retaining their functional capability under certain limiting conditions. However, the SFPCS retains a certain probability of successfully performing its function under harsh conditions. Therefore, the staff elected to evaluate certain capabilities deterministically, while random hardware failures and certain other effects were treated probabilistically. The results of deterministic evaluations are described below.

4.2.1 Normal SFP Cooling System Heat Removal Capability

The risk assessment model credited the additional heat removal capability resulting from higher than design SFP temperatures in evaluating the equipment availability necessary to prevent reaching a near boiling condition. To model the additional heat removal capability, the design heat removal capacity was scaled to reflect heat removal capability at the SFP temperature corresponding to near boiling. The scaled heat removal capacity assumed a counterflow heat exchanger with a constant heat transfer coefficient. The results indicated that each SFPCS heat exchanger had an approximate capacity of $10x10^6$ BTU/hr at a SFP temperature of 170°F with the SWS at its design temperature of 95°F, and with the SFPCS and SWS operating at their design flow rates. This value was used in the risk assessment model to assess the number of SFPCS pumps and heat exchangers necessary to remove the calculated decay heat rate and prevent the SFP from reaching a near boiling condition.

The licensee evaluated the heat removal capability of the SFPCS heat exchangers at design conditions. This evaluation was documented in calculation M-FPC-013, which the NRC staff reviewed during an audit at PP&L headquarters on December 3, 1993. The evaluation indicated that the total heat removal capacity for the three SFPCS heat exchangers at design conditions with 5 percent tube plugging exceeds the heat removal capacity specified in Reference 8 of $12.6x10^6$ BTU/hr. The staff found the calculational methodology acceptable.

4.2.2 Adequacy of Procedure ON-135/235-001, Rev. 13, Loss of Fuel Pool Cooling/Coolant Inventory

The risk assessment used human reliability assessment methods to assist in quantifying the probability of SFPCS restoration or other recovery actions based on the existing procedural guidance (See discussion in section 4.x.x). Procedure ON-135/235-001, Rev. 13, "Loss of Fuel Pool Cooling/Coolant Inventory," which became effective on June 30, 1993, provides direction in restoring the SFPCS or establishing alternate cooling if restoration of the SFPCS is not expected prior to pool boiling. NRC inspectors reviewed the adequacy of this procedure during an SSES site visit on January 12, 1994.

The initial operator action defined in the procedure is to determine the cause of the loss of fuel pool cooling. When the cause of the loss of SFP cooling is determined, the procedure directs performance of the applicable section(s) of the procedure to restore SFPCS operation following a loss of service water cooling, a loss of fuel pool cooling flow, or a system breach. Section 3.6 directs the response for instances where flow through the SFPCS cannot be re-established, including the use of the ESW system for providing makeup to the fuel pool. To add water using the Unit 1/2 ESW system requires opening valves 1/2-53500(1/2-535001), 1/2-53090-A(B), and 1/2-53091-A(B). The procedure specifies that a batch mode addition be used to accomplish makeup.

The licensee has calculated operator doses (See discussion of radiological assessment in Section 6.3 of this report) resulting from the manipulation of these valves following a design basis radiological release. The dose assessment was based on determining if adequate shielding is in place for operator access to a vital area. PP&L has indicated that valves 1/2-53090-A(B), and 1/2-53091-A(B) will be used for securing makeup between batches because they are expected to be in a lower dose area. This information had not been incorporated in the revision of ON-135/235-001 reviewed by the staff. Specifically, step 3.6.3 (4) directs the operator to close 1/2-53090-A(B), 1/2-53901-A(B), and 1/2-53500(1/2-535001), which would result in unnecessary operator dose to intermittently secure ESW.

For the purpose of the procedure walkdown the inspectors postulated a loss of cooling accident (LOCA) coincident with a loss of off-site power (LOOP). These conditions require the operator to enter section 3.6, which directs the response if fuel pool cooling cannot be established, including the use of the ESW system for providing makeup to the fuel pool. The inspectors evaluated the human performance concerns associated with implementing the procedure assuming that the ESW valve manipulations may be conducted in a high radiation environment and, therefore, may be conducted by an operator in full protective clothing and wearing an air pack. The procedure walkdown of the ESW alignment revealed that a nuclear plant operator (chosen at random by the inspectors) was able to readily locate the valves. The valves were clearly labeled and accessible for manipulation. Operator responses to questions concerning his ability to manipulate the valves revealed no concerns based on his past experience.

At the time of the site visit the control room did not have instrumentation providing fuel pool temperature or level indications. PP&L has since installed fuel pool temperature and level indications in the control room. The level instrumentation band encompasses the level required to maintain the Technical Specification required 22 feet of coolant over the irradiated fuel and the levels necessary for restoration of SFPCS flow or initiation of RHR flow in the SFP cooling assist mode.

During a telephone conference on May 26, 1994, the licensee indicated that procedures ON-135/235-001 would be modified to reflect the availability of level indication in the control room. The licensee subsequently submitted a modified procedure for staff review. Procedure ON-235-001, Revision 13, was changed under Procedure Change Approval Form No. 2-94-0144 to specify monitoring of SFP level and temperature using the control room SFP temperature and level indications following a loss of SFP cooling. However, the procedure continued to specify that monitoring of SFP level while providing make-up be based on observed level on the refueling floor or on surge tank level as indicated on LI-1/25312. Because the control room level indication is not fully qualified and redundant, the staff consideres these alternative methods appropriate for backup indication.

Determining fuel pool level using skimmer surge tank level indication requires an operator to determine at a local control panel whether LI-1/25312 is less than 100 percent, in which case the fuel pool is at an unknown level below the weirs. If LI-1/25312 is greater than or equal to 100 percent, an operator must initiate draining the skimmer surge tank to determine if the level is above the weirs. If skimmer surge tank level decreases below 100 percent the fuel pool level is below the weirs. However, according to the procedure, it would take approximately 80 minutes for the surge tank level to drop 10 percent. The inspectors noted that this method does not provide complete fuel pool level information, and access to the refueling floor to determine the coolant level above the weirs would have been necessary to reestablish SFPCS flow. In addition, dose rate at the local panel for LI-1/25312 may be high enough under assumed accident conditions that an operator would have to leave the panel and make a re-entry to evaluate the level indication after surge tank draining had been initiated.

In general the inspectors considered ON-135/235-001 adequate to restore SFP cooling and to accomplish the alignment of the ESW system for fuel pool makeup. The concerns noted would be expected to primarily affect operator efficiency in implementing the procedure and consequently would adversely affect efforts to minimize the radiological dose to the crews implementing the procedure under postulated radiological conditions associated with core damage following a LOCA. However, the event sequences leading to the postulated radiological conditions following a LOCA without SFP boiling were determined to be extremely low probability events and were excluded from consideration in the risk assessment.

4.2.3 LOCA Induced Hydrodynamic Piping Loads

A PP&L internal review (PLI-72288, dated September 1, 1992) identified the

possibility of LOCA-induced hydrodynamic loads affecting the integrity of FPC and service water (SW) piping, based primarily on the fact that they were not designed for such loads. The SW piping was included in the review since it provides cooling flow to the fuel pool heat exchangers. No evaluation of the ability of the piping to withstand these loads was contemplated at the time since the licensee believed that the event could be mitigated without use of the FPC system. A preliminary, quantitative assessment by the PP&L piping personnel in October 1992 subsequently concluded that the FPC and SW piping could be expected to remain functional under the hydrodynamic loads. It also concluded that should the FPC system be disabled, there were other actions which could be taken to mitigate the event. These were documented in the PP&L report NE-092-002, dated October 29, 1992. Based on these evaluations, Reference 1 described LOCA-induced hydrodynamic loads as a potential mechanism causing failure of the SFPCS and SWS piping.

By letter dated October 20, 1993 (Ref. 12), the staff sent the licensee a request for additional information (RAI), based on the material provided by the licensee in Reference 7, Reference 11, and a letter dated July 6, 1993 (Ref. 13), as well as staff comments made during telephone conferences with the licensee on October 18 and 19, 1993. This RAI requested a summary of the design criteria which the licensee originally used for the FPC and SW piping and hangers. It also requested the licensee to perform a more quantitative assessment for the integrity of the pertinent piping systems, under the hydrodynamic loads, in order to address the concerns raised by the authors of the 10 CFR Part 21 report.

On October 20, 1993, the NRC staff conducted an audit of the licensee's design calculations related to the FPC issue at the PP&L office in Allentown, Pennsylvania. The staff suggested that representative piping runs from the FPC and SW systems be analyzed dynamically for all the pertinent loadings, including deadweight, thermal, and hydrodynamic loads. The condensate transfer supply to the fuel pool pumps would not be required in the evaluation since the licensee determined that operation of the fuel pool cooling pumps would not be affected by a loss of these condensate lines. The licensee responded by providing additional information in its submittals of November 3, 1993, and December 8, 1993 (Refs. 14 and 15), where results of quantitative evaluations of FPC and SW piping were presented with the corresponding isometric drawings. A complete piping stress analysis report was provided with the January 6, 1994 submittal (Ref. 16).

4.2.3.1 Representative Piping

In the PP&L evaluation, large bore piping was considered representative because the majority of the FPC and SW systems consists of large bore piping. In addition, small bore pipe supports typically have larger design margins since they are often comprised of components designed to minimum vendor loads which often are significantly larger than anticipated loads. The majority of large bore FPC piping is located adjacent to the fuel pool heat exchangers and pumps. The suction lines to the FPC heat exchangers and the discharge lines from the FPC pumps in Unit 2 were taken to be representative of FPC piping. For the SW system, the discharge lines at the Unit 1 fuel pool heat exchangers, which are similar in size, layout and support configuration to the suction lines, were selected. In making the above selections, the following criteria were considered:

(1) The selected lines should encompass typical FPC pipe sizes, from 3" to 10" in diameter; and typical SW pipe sizes, from 8" to 24" in diameter.

(2) The selected lines should include equipment termination, i.e., heat exchangers and pumps.

(3) The selected lines should contain concentrated masses, e.g. valves.

(4) The selected lines should span various reactor building elevations, i.e., from elevation 719 ft. to 779 ft.

(5) The selected lines should be supported using typical pipe spans (B31.1) and pipe hanger designs. The typical pipe hanger design includes spring can hangers, rigid struts, rod hangers, stanchions, structural steel members, etc.

The staff found the above licensee's selection criteria to be acceptable, and the pipe lines selected were considered good representatives of the FPC and SW piping systems.

4.2.3.2 Analytical Methodology

The original design basis required the FPC piping to be designed in accordance with ASME Section III, 1971 edition with Addenda through Winter 1972, Nuclear Class 3. The design loadings considered were deadweight and thermal expansion. The piping stresses were calculated using a computerized linear elastic analysis method. The original pipe support design was based on ANSI B31.1, 1973, AISC, as well as vendor load capacities.

The SW system, on the other hand, is primarily of non-seismic design and is an ANSI B31.1 non-safety related system. It is mainly supported for deadweight in accordance with Bechtel field installation criteria. No piping stress calculations were performed because of its low design temperature.

The FPC and SW piping analyses as documented in the above January 6, 1994 submittal utilized the above original design basis methodologies, with the following exceptions: (1) all of the piping included in the assessment was analyzed using the computer code ME101 which is a verified Bechtel piping analysis program, and (2) hydrodynamic loads were considered along with deadweight and thermal expansion loads. This is found to be acceptable to the staff.

4.2.3.3 Hydrodynamic Loads

The load definition for Mark II hydrodynamic loads are provided in the Susquehanna Design Assessment Report (DAR). The LOCA-induced hydrodynamic loads include pool-swell loads, and steam-condensation loads due to the effects of condensation oscillation (CO) and chugging (CA) at the downcomer

exits during a LOCA blowdown. The "pool swell" phase of the LOCA, where the non-condensing gases are displaced to the wetwell causing a portion of the suppression pool water volume to be lifted, does not produce inertial effects on structures or components located outside of the pool swell zone. However, the containment structure and the remainder of the reactor building (including control structure) will experience steam-condensation inertial loads following a LOCA event. For areas inside the reactor building, but outside the containment, these hydrodynamic loads are the result of load transfer from the containment structure through the common foundation basemat.

Floor response spectra for the reactor building due to the hydrodynamic loads were generated for each of the floor elevations. Enveloped response spectra were further developed for each of the three orthogonal directions and were used in the analyses for the FPC and SW piping. These enveloped spectra contain high-frequency energy, typically in the range of 20 Hz to 60 Hz, in contrast to the low-frequency contents (between 2 to 10 Hz) for most earthquake spectra. The peak spectral accelerations were approximately 0.9g in the horizontal direction and 0.5g vertical, which are generally less than those of the corresponding earthquake floor response spectra developed for SSES.

The dynamic analyses were performed for the representative piping in the vertical direction and two horizontal directions. The internal moments, support reactions and stresses generated were then combined with those of system design pressure, deadweight and thermal expansion loadings in accordance with ASME Section III for FPC piping, or ANSI B31.1 for SW piping. Design loading combinations are as required in Tables 3.9-6 and 3.9-14 of Reference 8.

The staff found the licensee's analytical approach in developing the hydrodynamic loads and in combining with other loadings to be in accordance with the SSES design basis criteria and are, therefore, acceptable.

4.2.3.4 Analytical Results

A. Modal Frequency

The licensee stated in Reference 16, that the analyzed pipe lines are flexible, based on the results of modal analyses. The frequency ranges of the first five piping modes are 6.22 Hz to 26.81 Hz and 3.05 Hz to 9.99 Hz, respectively, for the two FPC pipes analyzed, and 0.53 Hz to 2.64 Hz for the SW pipe. The staff found these analyzed lines possess fundamental frequencies outside the LOCA response spectral peaks. As a result, LOCA loads will generally not be expected to generate significant piping responses.

B. Pipe Stress

The maximum pipe stresses due to hydrodynamic loads on the analyzed FPC pipes were less than 600 psi, which is less than 5% of the Code pipe stress for occasional loads. The maximum combined pipe stresses due to pressure, deadweight and hydrodynamic loads were

limited to less than 15% of the Code allowable. The maximum pipe stress due to hydrodynamic loads on the SW pipe occurred near a 24" diameter elbow and is less than 1600 psi. This is less than 10% of the Code allowable. The maximum combined pipe stresses occurred at the same SW location and were limited to less than 25% of the Code allowable. The staff found these results to be insignificant.

C. Pipe Support Loads

As stated in Reference 16, there is a total of thirty (30) pipe supports located on the FPC and SW piping which were evaluated by the licensee. Nine (9) of these supports are spring can hangers which do not restrain the pipe under dynamic loadings and are, therefore, not affected by the analysis. The remaining pipe supports are rigid type supports or in-line anchors which are comprised of various vendor components such as rigid rods, riser clamps, rigid struts and miscellaneous welded structural members such as tube steel, wide flange shapes, stanchions, plates, etc.

New pipe support loads were calculated for the FPC and SW pipe hangers subjected to deadweight, thermal expansion and hydrodynamic loadings. These new loads were used in the evaluation for the adequacy of pipe supports, by comparing them to the original design loads as provided in the existing Bechtel calculations (for FPC piping) or on the pipe hanger drawings (for SW piping).

The average increase in support loads due to LOCA were found to be less than 25% of the original design loads. In some cases new support loads were still found to be enveloped by the original loads. This was due to the conservatisms involved in the original support design using, for example, non-computerized analyses. In instances where the addition of LOCA loads resulted in new support loads which exceed the original support loads, these new loads were compared to the design margins available for each support component to ensure that the load increase could be accommodated. Where direct comparison with existing design margins could not be made, additional calculations were initiated by the licensee to demonstrate support adequacy. Based on the evaluations performed the licensee has demonstrated that all of the pipe supports have sufficient design margins to accommodate the addition of LOCA loads and that all the supports can be qualified in accordance with the original design allowable and vendor capacities.

The staff found the above licensee's evaluations of the supports to be acceptable.

D. Equipment Loads

The licensee used the new nozzle loads generated by deadweight, thermal expansion and LOCA loads in the evaluation of the three FPC pumps and fuel pool heat exchangers.

Each of the 3" diameter FPC pump discharge nozzles were evaluated based on the original vendor pump allowable provided in Bechtel Calculation ABR-2970. In addition, each of the 6" diameter FPC nozzles and each of the 8" diameter SW nozzles on the fuel pool heat exchangers were evaluated using the original design criteria provided in Bechtel Calculation ABR-2968. The licensee stated that for all these pump and heat exchanger nozzles the forces and moments calculated are within the allowable limits used in the original nozzle evaluations. The staff found this to be acceptable.

E. Pipe displacement

The licensee stated that in the analyses performed, the maximum LOCA pipe displacement is less than 0.100." Most displacements are less than 1/32." The staff agreed with the licensee that these displacements are insignificant in causing interface problems.

4.2.3.5 Conclusion with Regard to Effects of Hydrodynamic Loads on Piping

Based on the information provided, the staff found that the licensee has demonstrated, based on the representative sampling of lines chosen for the FPC and SW systems, that LOCA loads do not pose a significant threat to the integrity of these systems. The staff also found the licensee's approach of selecting the lines and the analytical methodology used in confirming the adequacy of FPC and SW piping to be acceptable.

The licensee's evaluation revealed that pipe stresses would increase slightly under the LOCA loads. The resultant pipe stresses under the combined loadings of deadweight, thermal expansion and LOCA loads are well within Code allowable. In addition, the licensee has found the pipe support design margins to be large enough to accommodate the additional LOCA loads and that equipment nozzle loads remain within original design basis allowable loads. The staff found the above results to be acceptable and concluded that there is no safety significance with regard to the overall effects of hydrodynamic (LOCA) loads on these two systems. Consequently, the risk assessment did not model flooding or SFPCS failures resulting from pipe breaks induced by a LOCA. However, the risk assessment did model random pipe ruptures as initiating events, which result in failure of the operating SFP cooling system (the SFPCS or the SFP cooling assist mode of RHR) due to flooding.

4.2.4 Environmental Effects on the SFPCS

The staff reviewed the calculated post-LOCA temperatures for reactor building areas containing SFPCS electrical components. The staff determined that the calculated temperature for these areas of approximately 115°F was unlikely to cause loss of the functional capability. The effects of postulated radiation fields associated with a design basis LOCA were not considered because of the extremely low probability of early core damage following a LOCA.

4.2.5 SFPCS Net Positive Suction Head Availability

The SFPCS pumps are provided with two design features to assure adequate available net positive suction head for pump protection: a surge tank low level trip and a low suction pressure trip. During an audit at PP&L headquarters on September 7, 1994, the staff reviewed calculation M-153-12, which documents an evaluation of the available net positive suction head and the low suction pressure trip setpoint. With the skimmer surge tank level at the low level setpoint, approximately 43 feet of elevation head is available; with each SFPCS pump operating at 600 gpm, friction head loss is approximately 30 feet. The required net positive suction head for the SFPCS pumps is 22 feet. Given these values, adequate net positive suction head is available for SFP temperatures up to 194°F. However, higher temperature water can be accommodated with 95°F service water flow available because the SFPCS heat exchangers are upstream of the pumps and are capable of cooling 212°F SFP water flowing at 600 gpm to less than 194°F. Because temperature related density effects on suction pressure are marginal, the low suction pressure trip is not a concern when skimmer surge tank level is above the low level trip setpoint. Consequently, the staff concludes that SFPCS flow can be restored without regard to SFP temperature when the service water system is available for heat removal.

4.2.6 Conclusions Regarding SFPCS Capability

Although the SFPCS lacks the redundancy and qualification of safety-related systems, the staff concluded that the system has a significant probability of retaining its functional capability. Hardware failures and human errors that impact the functional capability of the SFPCS are explicitly modeled in the risk assessment. The staff does not consider other potential system failure modes to significantly contribute to system unavailability.

4.3 Spent Fuel Pool Cooling Assist Mode of the Residual Heat Removal System

The 10 CFR Part 21 report authors communicated to the staff their concerns with regard to design limitations, procedural deficiencies, and operator dose associated with operation of the RHR system in the SFP cooling assist mode. In response, the staff evaluated the capability of the RHR system to provide adequate cooling of the SFP under a variety of conditions. The staff based this assessment on the procedure revisions and system modifications completed at the time of review, many of which had been implemented to respond to the indicated concerns. The scope of the staff review also included calculations, test results, and other documentation. The procedures for alignment of the RHR system in the SFP cooling assist mode and staff evaluation of RHR system capability in this mode were considered in the risk assessment model.

4.3.1 RHR System Performance in the SFP Cooling Assist Mode

The Part 21 authors expressed concern regarding the seismic qualification of the piping associated with the SFP cooling assist mode of RHR and the adequacy of available net positive suction head (NPSH) for RHR pump operation in the SFP cooling assist mode when SFP temperature is high. The staff reviewed these concerns based on the most recent calculations and procedures.

Although the SFP cooling assist mode of RHR was not originally a safety function of the RHR system, the piping necessary to support this function was qualified at SSES. Section 3.2 of Reference 8 describes the piping qualification of the SFPC and RHR systems. Based on a review of piping diagrams and Reference 8, the staff concluded that the portion of the RHR system and SFPC system piping used in the SFP cooling assist mode of RHR is constructed to ASME Boiler and Pressure Vessel Code, Section III, Class 3 and seismic Category I standards. However, the staff had noted that valves associated with this section of piping have not been included in the SSES Inservice Testing (IST) Program to regularly confirm the operability of this flow-path. Subsequently, in a letter dated August 8, 1994 (Ref. 17), PP&L committed to add these valves to the IST program and test their function on a refueling cycle frequency.

The staff also examined the adequacy of net positive suction head (NPSH) for one RHR pump operating in the SFP cooling assist mode. Based on vendor pump curves supplied by the licensee, the required NPSH for the RHR pumps is approximately 3 feet at 6000 gpm, which equates to a required NPSH of about 1.4 psia. This low value for required NPSH is consistent with the containment cooling safety function of the RHR system.

The staff calculated the head loss and the available NPSH for the SFP cooling assist mode of RHR using isometric drawings of the RHR and SFPC systems. The results of these calculations indicated that available NPSH is adequate for all expected SFP temperatures, including temperatures associated with a boiling SFP. The RHR pump suction pressure measured during pre-operational testing of the SFP cooling assist mode, which was documented in Reference 14, was 30 psig. Because the difference between available and required NPSH ((30 + 14.7) psia - 1.4 psia = 43.3 psia) disregarding temperature effects exceeds the maximum possible decrease in available NPSH at atmospheric pressure due to water temperature changes (14.7 psia), this test result supports the conclusion that adequate NPSH is available for operation of the RHR system in the SFP cooling assist mode at all expected SFP temperatures.

The staff also examined the capability of the SFP skimmer surge tank weirs to support stable operation of the RHR system in the SFP cooling assist mode. Calculation M-RHR-039, Revision 0, approved May 17, 1993, documented the licensee's evaluation of this capability. The calculation involved hydraulic analyses of the potential flow paths from an isolated SFP to the associated skimmer surge tank. Based on the analyses, the licensee determined that a SFP water level 8 inches above the bottom of the weirs, which approximately corresponds to a level 10 inches below the SFP curb, would provide sufficient flow to the skimmer surge tank to support stable operation of the RHR system at a flow rate of 5600 gpm in the SFP cooling assist mode. The licensee validated the results of the calculation to data from the pre-operational testing of the RHR system in the SFP cooling assist mode, which indicated that a flow of 5700 gpm was maintained at a SFP level 10 inches below the curb. Although the staff identified errors in hydraulic modeling for certain minor flow paths, the staff found the conclusions reached from the calculation were correct because the identified errors resulted in a conservative slight underestimation of the flow rate.

Subsequent to approval of Calculation M-RHR-039, the licensee revised procedures OP-149-003 and OP-249-003 for Unit 1 and Unit 2, respectively, "RHR Operation in Fuel Pool Cooling Mode." The revision included the addition of a provision to fill the SFP to a level approximately 8 inches below the SFP curb to ensure adequate flow to the skimmer surge tank. The 2 inch margin in SFP level and cautions to the operator contained in the procedure reduce the probability that contraction of the SFP water when cooling is initiated will cause inadequate flow to the skimmer surge tank.

Based on the above information, the staff concluded that, when operated in accordance with current procedures, the RHR pumps receive adequate flow to support stable operation in the SFP cooling assist mode. The risk assessment modeled failure modes of RHR in the SFP cooling assist mode that are associated with random failures and operator reliability issues.

4.3.2 Heat Removal Capability in the SFP Cooling Assist Mode

The Part 21 authors were also concerned that the effect on the UHS of using the RHR system in the SFP cooling assist mode had not been analyzed to their knowledge. The staff reviewed PP&L calculations related to this concern during audits at PP&L headquarters on December 3, 1993, February 7, 1994, and September 7, 1994. In addition, the risk assessment assumed that the heat removal capability of the RHR system in the SFP cooling assist mode was adequate to maintain the SFP below temperatures associated with near boiling for any potential decay heat load contained within the SFPs.

The licensee determined the heat removal capability of the SFP cooling assist mode of the RHR system and documented the results in calculation M-RHR-040, approved February 19, 1993. The calculation used a proprietary computer code, STER-3.22A (copyright 1987 by Holtec International), to evaluate the RHR heat exchanger performance in the SFP cooling assist mode. The vendor validated the code, and the licensee verified the code output for certain input conditions to the RHR heat exchanger data sheets. Based on a heat load of $33.9\text{x}10^6$ BTU/hr, which corresponds to the maximum heat load following power uprate for a full core off-load filling an isolated SFP at a time 250 hours after shutdown, the licensee determined that SFP temperature could be maintained below the administrative limit of 125°F at RHRSW temperatures below the Technical Specification limit for normal operation and below 130°F at the peak calculated post-LOCA RHRSW temperature. The staff concluded that the heat removal capability of the RHR system in the SFP cooling assist mode is acceptable for all anticipated heat loads in a single SFP, and the SFP cooling assist mode has adequate heat removal capability to prevent SFP boiling when one RHR loop is cooling both SFPs.

As one of several cases examined, the licensee determined the effect of heat rejection from the SFP through the SFP cooling assist mode of the RHR system to the UHS in Calculation EC-016-1002 (formerly M-RSW-043), Rev. 0, which was approved January 20, 1994. The calculation uses two Bechtel Corporation computer codes to model the thermal performance of the UHS and the spray nozzles for minimum heat transfer cases, which involve reduced spray effectiveness. Important general assumptions used in all cases included:

(1) Plant procedures ensure no RHRSW pumps are aligned to a spray loop

with a failed open spray bypass valve.

(2) Plant procedures ensure no ESW system heat loads are dissipated through a spray loop with a failed open spray bypass valve, except ECCS and RCIC room coolers.

(3) Plant procedures ensure operators control spray flow in a manner consistent with analyses.

(4) Suppression pool initial temperature is 100°F to support future Technical Specification (TS) revision (current TS suppression pool temperature limit is 90°F).

(5) Initially operating reactors were producing 102 percent of uprated thermal power.

(6) Minimum initial UHS temperature is 88.5°F (current TS maximum UHS temperature is 88°F).

(7) The RHR heat exchanger performance is derived from the design temperature effectiveness at an assumed RHR system temperature of 200°F and an RHRSW temperature of 88°F.

The most limiting set of evaluated cases with regard to peak UHS temperature were those cases involving a failed open (normally open) spray bypass valve. With a failed open spray bypass valve, only one spray loop is available for decay heat dissipation from the single RHR heat exchanger in each unit associated with that spray loop. With one unit experiencing a design basis LOCA and the other unit experiencing a rapid shutdown, the calculated peak UHS temperature was approximately 97.4°F at about 46 hours after the initiating event. The licensee selected 97°F as the design basis peak UHS temperature for power uprate based on an evaluation of the conservative nature of assumptions in the calculation. For these cases, fuel pool make-up water from the UHS via the ESW system was assumed to be provided to the SFP at a rate in excess of the calculated water loss from the SFP due to boiling following a seismic event in order to bound potential UHS inventory loss to SFP make-up.

A separate case evaluated the peak UHS temperature assuming SFP decay heat was rejected to the UHS via the SFP cooling assist mode of RHR. Because the codes are not capable of modeling the SFP cooling assist mode of RHR, the licensee modeled one LOCA unit with two RHR loops operating in suppression pool cooling, one non-LOCA unit with two RHR loops operating in shutdown cooling, and the SFP heat rejection as an essential service water (ESW) system load beginning 24 hours following initiation of the LOCA. The licensee did not consider failure of the spray bypass valve in the open position for this case. In Reference 6, the licensee stated that failure of the spray bypass valve is not considered a credible single failure for delayed functions such as SFP cooling because the valves are likely to be repaired or manually closed prior to the onset of SFP boiling and access to the valves is not restricted. The decay heat for each of the two units was based on two full power years of operation at the uprated power level, and the SFP heat rejection was assumed to be $18x10^6$ BTU/hr. Pump heat rejection to the UHS was also modeled.

The computed peak UHS temperature assuming the maximum rate of heat removal to the UHS and minimum heat transfer from the spray nozzles was 95°F at 44 hrs following LOCA initiation. The UHS peak temperature and inventory loss for this case are within design limits. In addition, the staff determined that, with the SFP at an initial temperature of 110°F and containing a decay heat production rate of 14×10^6 BTU/hr, the cross-connected SFPs have adequate thermal capacity without boiling to delay operation of the RHR system in the SFP cooling mode until after the peak UHS temperature has occurred and that decay heat from the SFP represents less than 20 percent of the total decay heat at the facility. Therefore, the staff concluded that operator control of the heat rejection to the UHS is adequate to prevent exceeding design temperature limits for all cases where the RHR system is operating in the SFP cooling assist mode. Because existing analyses that assume make-up for SFP boiling bound the potential inventory loss, the NRC staff concluded that UHS capacity is adequate to accommodate RHR system operation in the SFP cooling assist mode.

4.3.3 Procedural Adequacy for Initiation of the SFP Cooling Assist Mode

In response to the Part 21 authors' concern with regard to the adequacy of procedures for alignment of the RHR system in the SFP cooling assist mode, the staff performed an inspection relating to the adequacy of relevant procedures on January 12, 1994. If fuel pool cooling cannot be established, Step 3.6.2 of procedure ON-135/235-001 directs the placement of the RHR system in the fuel pool cooling assist mode in accordance with OP-149/249-003, "RHR Operation in Fuel Pool Cooling Assist Mode." The current procedure revision is OP-149/249-003, Revision 13, effective April 7, 1994, which was revised to include reference to the installed control room indication for SFP temperature and level. The inspectors conducted their review based on an earlier revision.

The inspectors conducted a walkdown of procedure section 3.8 which directs the alignment and vent operations in preparation for placing the fuel pool cooling mode of RHR in service. The inspectors' observations were generally consistent with the walkdown observations described in section 4.2.2. The valves were clearly labeled and accessible for manipulation. Operator responses to questions concerning his ability to manipulate the valves revealed no concerns based on his past experience. There was no emergency lighting in areas that required valve manipulation.

Section 3.8 contains a note prior to the step initiating filling of the fuel pool which states "It will be necessary to fill to a level of less than 8 inches from top of curb around Fuel Pool to obtain adequate level of RHR flow of approximately 6000 gpm." If the control room indication is unavailable, the inspectors believe that operators may not be able to judge the level with a sufficient degree of accuracy. The inspectors judged the pool to be greater than 30 feet from the door from which the observations would be made, and the pool did not have level markers that could be referenced. Licensee engineering personnel indicated that a level of 8 inches from the top of the fuel pool curb would allow RHR flow of 6000 gpm. A fuel pool level two inches lower would allow only 4000 gpm, indicating the sensitivity of RHR capacity to fuel pool level. Although operators could fill the fuel pool to levels

significantly higher than 8 inches from the curb, such an approach would increase the potential for flooding the refueling floor.

In Reference 11, the licensee estimated the time to fill the SFP to the appropriate level for RHR initiation in the SFP cooling assist mode to be from 2.5 to 22.6 hours depending on the SFP configuration and the number of ESW trains available for filling the SFPs. The licensee also estimated that the time to align the RHR system for the SFP cooling assist mode would be an additional 8 hrs. The longer fill times generally correspond to SFP configurations and decay heat rates associated with longer times to reach boiling conditions. Therefore, with appropriate administrative controls on SFP configuration, the licensee is capable of initiating RHR system operation in the SFP cooling assist mode prior to the onset of boiling in the SFP. Overall, the inspectors considered the guidance contained in the operating procedure adequate to align the RHR system for spent fuel pool cooling.

4.3.4 Alternate Decay Heat Removal

The staff chose to evaluate alternate decay heat removal methods in response to the Part 21 authors' concern with regard to limitations on RHR system operation with one loop of RHR in the SFP cooling assist mode. An alternate decay heat removal method for fuel within the reactor vessel is described in procedures ON-149/249-001, "Loss of RHR Shutdown Cooling," Revision 12, effective May 3, 1993. Because the SFP cooling assist mode and the shutdown cooling mode of RHR share common sections of piping, shutdown cooling is unavailable when the RHR system is operating in the SFP cooling assist mode.

One proceduralized alternate decay heat removal method uses the core spray system for injection to the reactor vessel from the suppression pool. Four safety relief valves (SRVs) are opened to allow water above the level of the SRVs to return to the suppression pool. The "B" loop of RHR is placed in the suppression pool cooling mode to remove decay heat from the suppression pool. In this configuration, the "A" loop of RHR is available for use in the SFP cooling assist mode. The staff found this method to be acceptable.

4.3.5 Diesel Generator Loading in the SFP Cooling Assist Mode

In response to the Part 21 authors's concern that EDG loading had not been evaluated with an RHR loop in the SFP cooling assist mode, the staff elected to review EDG load profiles for various instances. The staff reviewed emergency diesel generator (EDG) operation and loading profiles described in section 8.3 of Reference 8. The four installed EDGs are rated for 4000 kW continuous loading and 4700 kW for 2000 hrs on each of the four vital buses. In addition, a fifth EDG rated at 5000 kW continuous loading is available to perform the safety function of any one of the four primary EDGs. Section 8.3 of Reference 8 states that the loading of each EDG is maintained below 4000 Kw by procedure, and only one RHR pump can be loaded on any one EDG.

In response to a staff request for additional information, the licensee submitted EDG loading tables as an attachment to Reference X+5. The loading tables were calculated assuming the following conditions:

(1) unit 1 and unit 2 operating at full power

(2) seismic event

(3) loss of unit 1 and unit 2 SFP cooling systems

(4) extended loss of off-site power

(5) reactor shutdown cooling provided by alternate decay heat removal

(6) single failure of one EDG

These loading tables indicated that EDG loading for the assumed conditions will be within the continuous load rating of the EDGs. These tables are also bounding for the time greater than 60 minutes following the event with respect to EDG loading for a LOCA with a single EDG failure. However, simultaneous cooling of both reactor vessels and both SFPs is not possible with a single EDG failure and no communication between the two SFPs. Therefore, one SFP would be expected to boil assuming an extended loss of off-site power and failure of a single EDG. In Reference 5, the licensee committed to change applicable procedures such that SSES will normally operate with the SFPs cross-connected by June 30, 1994. This action eliminates single failure concerns with regard to the plant's response to a design basis seismic event with an extended loss of off-site power.

The NRC staff also reviewed EDG loading tables presented in an attachment to a letter dated August 8, 1994 (Ref. 18). These loading tables assumed the same conditions described above with the exception of failure of an EDG. Based on the NRC staff's review of these loading tables, the NRC staff concluded that both reactor vessels and both SFPs can be cooled simultaneously without exceeding the continuous load rating of the EDGs during the period greater than 60 minutes following a LOCA or seismic event.

4.3.6 Conclusions Regarding the SFP Cooling Mode of the RHR System

Based on our review, the staff concluded that the SFP cooling assist mode of RHR provides a reliable method of cooling one or both SFPs at SSES. The staff found that the system design is adequate to provide SFP cooling. The staff also concluded that adequate procedures had been developed and adequate support system capability was available to provide SFP cooling and simultaneous reactor vessel cooling with the RHR system.

4.4 Effects of Boiling Spent Fuel Pool On Safety Systems

Although PP&L has since made modifications that have improved the availability of the RHR system to operate in the SFP cooling assist mode to an extent that SFP boiling is highly improbable, the NRC staff conducted an inspection of SSES on December 2, 1993. The inspection purpose was, in part, to determine potential propagation paths for vapor evolved from a boiling SFP on the refueling floor to other areas of the reactor building. Based on a walkdown of the refueling floor and discussions with PP&L personnel, the NRC staff concluded that the only credible propagation paths were via the reactor building drain system and the reactor building ventilation systems. The inspectors noted that all personnel access points to the refueling floor were isolated from the remainder of the reactor building by air locks.

4.4.1 Flooding by Condensate

Following the onset of SFP boiling, substantial condensation will occur throughout the refueling floor. Some condensation may occur on the surface of an adjacent cool SFP or other location where condensate can collect without draining from the refueling floor. However, the majority of condensation is likely to occur on the structure forming the boundary of the refueling floor, and the condensate from these surfaces will be collected primarily by the reactor building drain system. Condensation occurring outside of the refueling floor will be addressed in Section 4.4.2 of this safety evaluation.

Each unit directs liquid collected in its reactor building drain system to its respective reactor building sump room. The reactor building sump rooms are located adjacent to the "A" core spray room, which contains the two core spray pumps associated with the "A" core spray loop, and a flood barrier is not provided between the "A" core spray room and the reactor building sump room. Adjacent rooms in the reactor building basement on the 645' elevation are protected by flood barriers, including normally locked-closed isolation valves in the drain system lines and watertight doors.

PP&L credited the flood barriers to a level of 23 feet based on the design of the watertight doors and hydrostatic test pressure of the doors. However, the NRC staff noted that two watertight doors must retain differential pressure in the unseating direction to prevent the spread of water from the reactor building sump rooms to the "A" RHR pump room and the "B" core spray pump room, and the specified differential pressure for these doors in that direction is 0. In Reference 6, PP&L stated that these particular watertight doors were not hydrostatically tested in the unseating direction, but the doors were designed to be watertight in both directions to an equivalent degree. Based on the design of the watertight doors and the provision of safety-grade instrumentation within ECCS pump rooms to provide early indication of flooding, the staff concluded that the existing watertight doors provide adequate assurance that flooding of ECCS pump rooms adjacent to the "A" core spray room/reactor building sump room would be prevented or mitigated in the event of long-term SFP boiling.

PP&L evaluated the time for the condensate resulting from a boiling SFP to fill the sump room/"A" core spray room to a level of 23 feet. This evaluation is documented in calculation EC-035-0510, Revision 1, which the NRC staff reviewed during an audit at PP&L headquarters on February 7, 1994. The assumptions of the evaluation included: an isolated, boiling SFP with a decay heat rate of $10.24x10^6$ BTU/hr yielding 22 gpm of condensate; the drain system collects approximately 90 percent of the condensate; half of the condensate collected by the drain system accumulates in each unit's sump; the ventilation systems do not exhaust any moisture; and the remaining condensate collects in pools on the refueling floor. The results of the evaluation indicate that the "A" loop of each unit's core spray system would be the only equipment failure caused by condensate flooding within the first 30 days following the onset of SFP boiling. This assessment is not bounding, but the NRC staff concluded that considerable time is available for recovery actions to prevent additional equipment failures due to flooding.

The total loss of the core spray system functional capability due to condensate flooding was addressed by a sensitivity study in the risk assessment. The NRC staff considers this sensitivity study adequate to address the concern with regard to flooding of adjacent ECCS pump rooms.

4.4.2 Temperature/Humidity Effects

4.4.2.1 Environmental Qualification of Equipment

PP&L conducted evaluations of the environment within the reactor building for various ventilation system alignments. PP&L concluded that positive ventilation from the refueling floor to outside the reactor building is necessary to prevent adverse environmental effects on equipment within the reactor building during a LOCA with a boiling SFP. Operation of the SGTS with the recirculation fans off provides the necessary positive ventilation of the refueling floor, and this alignment can be initiated from the control room following any postulated design basis event.

The NRC staff reviewed an analysis of the environmental effects of a single boiling SFP during an audit at PP&L headquarters on February 7, 1994. PP&L documented the reactor building room temperatures resulting from a single boiling SFP in calculation EC-035-0513 (formerly calculation M-FPC-015), Revision 0, which was approved on December 21, 1993. Evaluation SEA-00-550, Revision 0, which was approved on December 10, 1993, evaluated the impact of increased reactor building room temperatures calculated in M-FPC-015 on the completion of the safety function of reactor building equipment.

Calculation EC-035-0513 was intended to maximize the secondary containment temperature response to a boiling SFP, and the calculation included the following significant assumptions:

(1) no condensation within secondary containment

(2) SGTS operating

(3) pressure response of the refueling floor selected to maximize reactor building temperatures

(4) no evaporation from SFP surface prior to onset of boiling

(5) recirculation fans secured at onset of boiling

(6) make-up supplied to the SFP to compensate for a boiling rate of 10,000 lb/hr

(7) SFP cooling is lost at time of LOCA

(8) emergency switchgear room fan operating with cooling coils receiving 27 gpm of control structure chilled water at 47°F

(9) safety-related room coolers provide sensible heat removal only.

Based on the capability of the SGTS to ventilate a greater volumetric flow rate than the assumed volumetric rate of vapor production from a boiling SFP and the configuration of the safety-related ventilation systems, the staff concluded that consideration of the effects related to vapor propagation is not necessary for safety-related systems and components with the exception of the SGTS. The staff also found the remaining assumptions to be acceptable with regard to the purpose of the analyses.

With the above assumptions, PP&L calculated the resulting room temperatures for all rooms within the reactor building secondary containment zones using a proprietary compartment temperature and pressure response code developed by PP&L, COTTAP. The resulting temperatures were compared with the temperature limits established for each room in the environmental qualification assessment reports (EQARs) in evaluation SEA-EE-550. The EQAR temperatures are based on analyses of room temperature response to the post-LOCA environment, and equipment within the room is qualified to at least the EQAR temperature. If the EQAR room temperature exceeded the temperature from the COTTAP analysis, no further evaluation was necessary. Otherwise, the actual qualified room temperature was determined based on the qualification of individual Class 1E components, and the actual qualified room temperature was compared to the temperature from the COTTAP analysis. If the actual qualified room temperature exceeded the temperature from the COTTAP analysis, no further evaluation was necessary. Otherwise, PP&L evaluated the qualification of individual components with regard to the effect of accelerated aging caused by the higher COTTAP temperature and the effect of potential failure modes on the ability to provide long-term cooling.

The evaluation documented in SEA-EE-550 concluded that the ability to provide long-term cooling of the reactor vessel would not be threatened under the assumed conditions. The staff concluded that the evaluation was conservative and that the methodology was acceptable. However, the staff noted that the evaluation conclusion was based on preventing exposure of most safety-related components to the steam environment produced by a boiling SFP. PP&L's evaluation assumed that isolation of safety-related components would be accomplished by operating the SGTS with the recirculation fans off such that the vapor produced on the refueling floor would be ventilated to the atmosphere by the SGTS.

4.4.2.2 Qualification of the SGTS for a Steam Environment

The SGTS provides the only safety-related means of ventilating the refueling floor to atmosphere during a SFP boiling event and isolating safety-related components from the refueling floor environment. Therefore, the ability of the SGTS to retain its functional capability throughout a SFP boiling event is must be considered in evaluating the effects of a boiling SFP on safety-related equipment. In addition, the authors of the Part 21 report expressed concerns regarding the effects of high temperatures on SGTS components and accumulation of condensate within the SGTS.

Based on PP&L's evaluation of the postulated scenario described in Reference 1 for accessibility and time to reach boiling conditions, PP&L concluded that no more than one SFP would boil. This conclusion was based on automatic isolation of the LOCA unit secondary containment zone and Zone III from the non-accident unit on a LOCA alone, and the ability of operators to initiate isolation of the LOCA unit secondary containment zone and Zone III from the non-accident unit by manual actions in the control room for a LOCA/LOOP. Early isolation prevents buildup of significant airborne activity within the non-accident unit assuming the source term of the scenario postulated in the Reference 1. Therefore, the licensee considered access to the non-accident unit to be unrestricted. In addition, the licensee evaluated the time to reach boiling conditions in the non-accident unit's SFP considering potential decay heat rates and typical pool configurations, and determined that adequate time would be available to initiate a means of SFP cooling prior to reaching boiling conditions.

Because one pool may boil in this scenario and the licensee determined that SGTS operation without recirculation would be necessary to prevent adverse environmental effects on safety-related equipment within the accident unit, the licensee elected to evaluate the effects of a boiling SFP on the SGTS. This evaluation was documented in the following calculations: EC-035-1001, Revision 0, which evaluated the refueling floor environment for one boiling pool; EC-070-1002, Revision 0, which evaluated the accumulation of moisture in the recirculation plenum and the condensation rate of vapor in the SGTS ductwork as a function of length for a range of inlet conditions; EC-034-1003, Revision 0, which calculated the inlet conditions to the SGTS ductwork; and EC-070-1003, Revision 0, which evaluated the effect of condensation on the SGTS ductwork. The staff audited these calculations during a visit to PP&L's corporate headquarters on February 7, 1994.

These calculations included the following significant assumptions:

(1) The decay heat rate in the boiling SFP is 8.2×10^6 BTU/hr, which equates to the SFP decay heat rate for a one-third core off-load that completely fills the SFP at 51 days after shutdown.

(2) Condensation occurs on the refueling floor structure (i.e., walls, ceiling, and floor) and the surface of the SFP with an operable cooling system.

(3) Inleakage of 1000 CFM enters each secondary containment zone.

(4) SGTS inlet conditions were calculated by mixing flow of 1000 CFM from each zone and the pressure driven flow caused by SFP boiling from Zone III.

Based on assumptions (1) and (2), PP&L calculated the average conditions on the refueling floor as a function of time using PP&L's proprietary compartment

pressure and temperature response code, COTTAP. PP&L calculated the moisture accumulation in the recirculation plenum by integrating the calculated concentration of condensed vapor entrained in the flow entering the recirculation plenum (1000 CFM inleakage plus pressure driven flow). PP&L determined the SGTS entry conditions by calculating the thermodynamic state developed by mixing the air flow from Zone I and Zone II with the flow from Zone III assuming the entrained moisture was deposited in the plenum. PP&L evaluated the condensation accumulation in the SGTS ductwork by calculating and integrating the condensation rate for discrete lengths of SGTS ductwork. PP&L then evaluated the effects of the accumulated condensate on the structural integrity of the SGTS ductwork and the SGTS flow. PP&L adequately justified this approach to the staff, and the staff found the methodology and assumptions used in this analysis to be reasonable.

The results of this analysis indicated that an unanalyzed condition would be reached within several days following the onset of pool boiling. The unanalyzed condition was accumulation of condensate within the recirculation plenum to the extent that water overflowed into the SGTS ductwork. The increased rate of condensate accumulation due to the overflow from the recirculation plenum may result in structural failure of the SGTS ductwork or a blockage of flow such that the SGTS may be unable to perform its design function of maintaining affected secondary containment zones below atmospheric pressure.

As a result of the analysis of the effects of a single boiling pool on the SGTS, the staff questioned the ability of the SGTS to adequately ventilate the refueling floor following a seismic event. As identified in Appendix A to this report, the staff determined that initiation of a loss of SFP cooling by a seismic event is included in the current licensing basis for SSES. At the time of licensing, the staff accepted this condition based on the provision of the SGTS, which is designed to ventilate the refueling floor to atmosphere. Because the staff postulated that a seismic event causes failure of both SFPCSs, the SFP that acted as a heat sink in the analysis of a single boiling pool would also be boiling. Consequently, the staff believed that the effects of a seismic event on SGTS operation would be more severe.

PP&L performed an analysis in response to NRC staff questions to evaluate the effects of a total loss of SFP cooling initiated by a seismic event on the SGTS. PP&L submitted the results of this analysis in an attachment to a letter dated May 4, 1994 (Ref. 19). The analysis used assumptions similar to those used in the analysis for a single boiling pool, except that the cooling effect of inleaking air was credited in this analysis. Also, the decay heat rate for the pools was based on two one-third core off-loads that filled each of the pools. The off-loaded fuel had been used in two units that reached shutdown 35 days and 135 days prior to the seismic event, respectively. The results of this analysis indicate that a similar unanalyzed accumulation of condensate in the recirculation plenum would occur about 17 hours following the onset of boiling.

Clearly, the outcome of an evaluation of SGTS performance during SFP boiling events is dependant on the rate of steam generation, which is determined by the decay heat rate of fuel stored in the pools and the available heat sinks on the refueling floor. The number of heat sinks is determined in part by the number of pools boiling. Therefore, the staff did not consider additional evaluations of SGTS performance to be necessary. The staff simply concluded that the SGTS may be used to extend the time between a loss of SFP cooling and the beginning of adverse environmental effects in reactor building Zones I and II.

Based on the above results, the staff concluded that the SGTS design is not capable of accommodating the environmental effects associated with SFP boiling. As described in Appendix A to this report, NRC staff acceptance of a SFPCS not qualified to seismic Category I standards was based on the provision of the SGTS, which Reference 8 described as satisfying the recommendations of Regulatory Guide 1.52 (Ref. 20), to ventilate the refueling floor. Reference 20 includes environmental design criteria for the SGTS, which include basing the design on the relative humidity, maximum temperature, and other conditions resulting from the postulated accident, and the duration of the conditions. However, this licensing basis linkage of SGTS performance in a boiling SFP environment is tenuous at best.

Early restoration of the SFPCS would not be expected based on its non-seismic design. However, PP&L has indicated that boiling of the SFPs will be prevented by using the SFP cooling assist mode of RHR when the SFPCS is unavailable. The commitment to cross-connect the SFPs that PP&L made in Reference 5 improves the availability of one loop of the RHR system to operate in the SFP cooling assist mode and eliminates concerns regarding potential single failures (see Section 4.3). The staff concluded that this approach provides acceptable assurance that SFP boiling will be prevented.

The staff has requested that PP&L submit a formal commitment to fully qualify the SFP cooling assist mode of RHR such that this system may be credited in the licensing basis to prevent SFP boiling. However, this commitment has not been received for review as of the date of issuance of this SE.

4.4.2.3 Risk Assessment Modeling of Environmental Effects

In order to assess the impact of pool heat-up and boiling on plant operation, it is important to have an understanding of the ventilation systems and their interactions. The secondary containment design and the associated ventilation systems provide isolation and atmospheric ventilation capability that decreases the probability of adverse environmental effects on equipment as a result of pool boiling events.

The normal reactor building ventilation system may remain in operation following certain loss of SFP cooling initiating events evaluated in the risk assessment. Initiating events such as internal flooding, pipe breaks, loss of the SWS, and loss of the normal SFPCS do not initially have plant-wide effects. Therefore, no early impact on the operation of the reactor building ventilation system would be expected. Because Zone III, which encompasses the refueling floor, is isolated from the remainder of the reactor building and ventilated directly to atmosphere with the normal ventilation system operating, the environmental effects of a loss of SFP cooling are isolated from equipment located in Zone I or Zone II. Based on the relatively high rate of normal ventilation flow and the low rate of evaporation from the SFP prior to the onset of boiling, the staff concluded that environmental failure of equipment is unexpected prior to the onset of boiling for these initiating events.

Conversely, other initiating events such as a LOCA or a LOOP, which generate a reactor building isolation signal, automatically secure the normal reactor building ventilation system for the affected zone(s), start the recirculation system for the affected zone(s), and starts SGTS. Consequently, the Zone III environment is mixed with the affected zone(s), but any unaffected zone would continue to operate with the normal reactor building ventilation system, which remains separate from the recirculation system. If a LOCA occurs coincident with a reactor building isolation signal affecting all zones (i.e., a dual unit LOOP), then emergency operating procedure EO-100-104, "Secondary Containment Control," directs restoration of normal reactor building ventilation when: (1) an entry condition other than area radiation monitor level greater than maximum normal value is satisfied for the non-LOCA unit; (2) normal zone ventilation is available, which requires restoration of power; (3) all area radiation levels remain below the maximum normal value; and (4) SGTS release rates are below the maximum normal value. However, the physical capability exists to block the transfer of contamination between the LOCA and non-LOCA unit, and the licensee may develope procedures to perform this function in situations where secondary containment control entry conditions are not satisfied to manage the potential spread of radioactivity following a postulated release.

4.4.3 Conclusions Regarding the Effects of Pool Boiling

Although plant modifications have substantially reduced the potential for SFP boiling at SSES, the staff evaluated potential environmental effects from a boiling SFP. The staff conducted the evaluation in part to support the risk assessment modeling, with an understanding that a thorough assessment of the effects of steam propagation throughout the reactor building was impractical. However, PP&L performed a practical evaluation of the effects of SFP boiling with the SGTS operating and the recirculation system secured. In this configuration, a propagation path through the emergency ventilation system for steam to travel from the refueling floor to other ares of the reactor building was blocked.

The evaluation by PP&L demonstrated the adverse effects of pool boiling on the limited number of systems exposed to the resulting environment. Flooding by condensate was demonstrated to be manageable for an extended period without substantially affecting safety-related systems other than one loop of core spray in each unit. The SGTS endurance in the environment was restricted to a far greater degree. These results largely confirm the contentions of the Part 21 authors. Accordingly, PP&L has focused on means to prevent pool boiling.

5.0 RISK ASSESSMENT OF LOSS OF SPENT FUEL POOL COOLING EVENTS

The staff concluded that several aspects of the scenario described in Reference 1 are best addressed using risk assessment techniques. Because the risk assessment used realistic assumptions in evaluating initiating events and subsequent consequential events, the staff did not apply the assumed radionuclide release associated with a design basis LOCA described in the report, and the staff provides a realistic basis for the radionuclide release used in the staff's radiological review presented in Section 6.0. In addition, the authors have raised a concern regarding the consequences associated with damage to the fuel stored in the SFP that the staff can best address by evaluating the added risk from this potential release path.

5.1 LOCA Radionuclide Release

All nuclear power plants, including SSES, are designed with redundant emergency core cooling systems to prevent damage to fuel contained within the reactor vessel following a LOCA. Using conservative assumptions regarding the performance and availability of these systems, the staff evaluates these systems during licensing to ensure that fuel cladding failure will not occur as a result of a LOCA. Consequently, the probability of fuel cladding damage following a LOCA is very small.

In order for access to the reactor building to be restricted following a LOCA, significant core damage must result from the LOCA. The probability of reaching core damage was evaluated for several facilities in NUREG-1150 (Ref. 21). The staff concluded that, of the facilities examined for Reference 21, the core damage results for Peach Bottom would be most representative of SSES. The median core damage frequency for all LOCA initiators at Peach Bottom is $2x10^{-7}$ per reactor year, which includes both early and late radionuclide releases. For comparison purposes, the results of 18 Individual Plant Examinations for boiling water reactors indicated a median core damage frequency for LOCA initiated events of $2x10^{-7}$ per reactor year, with a range from $8x10^{-9}$ to $4x10^{-6}$ per reactor year.

Because early core damage is necessary to prevent restoration of SFP cooling after a LOCA due to access concerns alone, the frequency of events that approximate the radiological conditions described in Reference 1 is a subset of the frequency of core damage events for all LOCA initiators. To verify that significant core damage is necessary to prevent access to the reactor building, the staff evaluated the effect of a release of 100 percent of gap activity on the ability of operators to complete various actions to restore the spent fuel pool cooling function (see Section 6.1). The staff concluded that gap activity releases would not threaten operator access. Therefore, the staff concluded that concerns with regard to the inability to restore SFP cooling due to the radiological conditions created by a LOCA are not safety significant.

5.2 Risk Associated with a Total Loss of Spent Fuel Pool Coolant

Because spent fuel is typically stored in high density racks and some evidence of fire propagation potential between fuel assemblies stored in a dry condition exists, the staff evaluated the risk associated with beyond design basis accidents in spent fuel pools as Generic Issue 82. The basis for resolution of the issue is documented in NUREG-1353 (Ref. 22).

The resolution of Generic Issue 82 considered a number of initiating events that have the potential of completely draining the SFP. A total loss of fuel pool cooling and make-up capability was included as an initiator, in addition to other initiating events that more directly drain the spent fuel pool. Seismic events and sustained loss of SFP cooling and make-up initiators were found to dominate the total loss of SFP coolant inventory sequences for BWRs at 6.7×10^{-6} per reactor year and 1.4×10^{-6} per reactor year, respectively. However, when recovery actions are considered, the estimated probability of a sustained loss of SFP cooling and make-up drops to 6.0×10^{-8} per reactor year

The consequences of a spent fuel fire initiated by the temperature increase from a loss of coolant was calculated for the resolution to evaluate risk. Assuming the fire propagates to all fuel assemblies in the pool and the release is direct to atmosphere, the best estimate of consequences of the release was calculated to be 8.0×10^{6} person-rem to a population with a density of 340 persons per square mile within a 50 mile radius from the site as a result of the release of radionuclides from the last fuel discharge (one third of a reactor core) 90 days after shutdown. However, due to the absence of short-lived isotopes in releases originating from the SFP, the risk of early injuries or fatalities from SFP releases is negligible in comparison with a severe core damage accident.

Because the release from a spent fuel fire initiated by a seismically induced loss of SFP coolant was assumed to breach secondary containment, the regulatory analysis found the risk from seismic initiators to be dominant. Loss of cooling sequences were assumed not to have significant off-site consequences because the fuel assemblies would be oxygen starved by steam evolution and blockage of air circulation by the remaining water for several days, preventing development of a spent fuel fire. Consequently, the release would result from spent fuel cladding perforation only and be mitigated by SGTS and secondary containment.

The calculated off-site consequences for a sustained loss of SFP cooling and make-up was 4.0 person-Rem per event assuming half of all fuel assemblies leaked 1 year after the last discharge. This level of consequence failed to justify modifications to the SFP cooling or make-up systems on a safety enhancement basis, and is not significant relative to postulated severe core damage accidents. Because of the generic nature of the regulatory analysis and certain bounding assumptions used in the analysis, the staff does not consider the numerical results of the regulatory analysis to be directly applicable to SSES. However, the staff concludes that the calculated consequences from a postulated sustained loss of SFP cooling and make-up at SSES would be similarly small.

5.3 SSES Risk Assessment for All Loss of Spent Fuel Pool Cooling Initiators

In investigating the concerns raised in Reference 1, the staff determined that there was sufficient merit in the broader context of the issues raised (i.e.,

the effect on core damage prevention and mitigation capabilities from loss of cooling to the spent fuel pools) to investigate their safety significance in a systematic manner. The staff chose to use risk assessment techniques to perform this investigation. The Susquehanna spent fuel pool risk assessment (risk assessment) is a first-of-a-kind effort by the NRC at estimating the likelihood of core damage caused by the boiling of spent fuel pools.

The staff partitioned the risk assessment into two parts. The first part (Phase I) examined the frequency with which events would cause a loss of cooling to the spent fuel pools that lasted long enough for the pools to heat up and begin to release large quantities of water vapor and heat to the air space above the pools. This near boiling frequency (NBF) measures the likelihood that either cross-connected spent fuel pools will reach a bulk pool temperature greater than 170 °F in the cooler of the two pools or that for an isolated pool its bulk temperature will be greater than 200 °F. The second part of the risk assessment (Phase II) examined the likelihood that such an event would in turn lead to core damage. To help provide these insights, the staff in conjunction with Batelle Pacific Northwest Laboratory (PNL) developed a systematic risk assessment, involving both quantitative and qualitative methods, of events at Susquehanna that potentially lead to loss of cooling to the spent fuel pools (SFPs). The specific objective of the risk assessment was to provide a perspective of incremental core damage frequency (CDF) due to loss of spent fuel pool cooling events.

The risk assessment was performed in such a manner as to provide results and insights that are realistic, but certain effects that the staff judged to be difficult to quantify (e.g., the time for steam propagation to adversely effect equipment in the reactor building) were modeled in a conservative manner. The staff believes that the numerical results and qualitative insights are sufficiently robust, realistic, and detailed that potential uncertainties in the modeling or assumptions would not invalidate the safety conclusions made from the assessment. All numerical results generated by the risk assessment are point estimates.

Because the risk assessment's objective was to provide a perspective of how much the CDF might increase due to loss of spent fuel pool cooling events, the risk assessment excluded sequences from its CDF totals where the core would have been damaged regardless of whether or not there was pool boiling.
The staff used two screening criteria to identify the most important sequences where spent fuel pool boiling leads to core damage:

(1) frequency of spent fuel pool boiling greater than $1x10^{-6}$ per year

(2) boiling begins less than 50 hours after onset of loss of spent fuel pool cooling

Section 5.3.3 of this SE provides a narrative of the timelines associated with the most important sequences where pool boiling leads to core damage. The narrative describes the assumptions and most likely failures, operator actions, and consequences of these events as modeled in the risk assessment.

The staff investigated the risk associated with spent fuel pool boiling for the Susquehanna units as they currently are configured and operated (the "as-fixed" units). The risk assessment found that the risk (i.e., likelihood of a boiling spent fuel pool causing core damage) from loss of spent fuel pool cooling events as the units are configured and operated today is quite low (NBF estimated to be on the order of $1x10^{-5}$ per year with the incremental risk of core damage several orders of magnitude less). In addition, the staff identified the magnitude of risk that may have existed for the Susquehanna units when the concern about loss of cooling was initially recognized (the "as-found" units). The staff concludes that this risk was low at the time that this concern was discovered and was about a factor of four greater than it is today. The staff's risk assessment estimates the frequency of pool boiling for the as-found units was about $4x10^{-5}$ per year with the incremental CDF estimate being several orders of magnitude less. The staff determined that the most important sequences that could lead to pool boiling and consequential core damage in either the as-fixed and as-found units are extended loss of offsite power and LOCA sequences.

The staff's assessment only evaluated the potential for contribution to core damage from initiating events with estimated NBFs (totaled for all cases where estimated times to boil were less than 50 hours) of greater than $1x10^{-6}$ per year. Initiating events with a total estimated annual NBF of less than $1x10^{-6}$ are considered to provide a negligible or insignificant potential contribution to core damage. Likewise, cases estimated to reach near boiling conditions at greater than 50 hours are considered to have sufficient time to restore cooling to the SFP(s) or to prevent adverse conditions in the reactor building before near boiling conditions develop. Thus the ECCS equipment required for core cooling will have completed the required safety functions or will be otherwise protected for accident sequences with estimated time to near boiling conditions of greater than 50 hours after the initiating event. Therefore, the initiating events with an estimated total annual NBF for all cases of less than $1x10^{-6}$, and cases that have an estimated time between initiating event and reaching near boiling conditions of greater than 50 hours are not evaluated for potential contribution to core damage.

5.3.1 Risk Assessment Methodology and Modeling

For the as-fixed condition, the staff developed quantitative estimates of NBF for the Susquehanna units. The NBF measures the likelihood that the spent fuel pools will reach a temperature (i.e., bulk spent fuel pool temperature in the cooler pool > 170 °F or > 200 °F for an isolated pool) high enough to release significant amounts of water vapor and heat to the air space above the pools. The staff generally performed the quantification of the risk assessment using probabilistic risk assessment (PRA) methods as described in NUREG/CR-2300 (Ref. 23). Data for event sequences, system operation, and event probabilities were evaluated based on (1) plant-specific information including the Susquehanna Individual Plant Examination, the Susquehanna mini-PRA for the spent fuel pool, PP&L submittals and responses to staff questions, staff site visits, and SSES procedures, (2) other plant individual plant examinations (IPEs) (e.g., Trojan IPE, WNP-2 IPE, Oconee IPE, and Surry IPE), (3) other plant PRAs (e.g., NUREG-1150 (Ref. 21)), and (4) generic information. Important assumptions made by the staff in performing the risk assessment have been summarized in Table 5.A of this SE.

Results and insights from the risk assessment are based on the staff's investigation of loss of spent fuel pool cooling initiating events; the mitigating structures, systems, and components in the Susquehanna units; meetings with PP&L; and Susquehanna site visits. The staff chose to use qualitative or semi-quantitative methods for these cases for several reasons including the following: (1) the difficulty in quantifying operator errors or utility mitigation capabilities in situations where operators have tens of hours to respond correctly, (2) the lack of accurate data on the temperatures at which equipment would fail in steam environments, (3) the concern that there may be important failure modes caused by a steam environment that cannot be modeled readily in the analysis (e.g., steam condensation in conduit could short out the cables), and (4) the difficulty in accurately predicting the speed with which high temperature and humidity would spread throughout the secondary containment following pool boiling.

In Phase I the staff identified important initiating events and sequences leading to near boiling temperatures in the spent fuel pools. Initiators evaluated included failure of the spent fuel pool cooling systems, loss of offsite power, seismic events, service water pipe breaks, and LOCAs. The staff developed event trees and fault trees for the response of the SSES units to loss of cooling to the spent fuel pools. Fault trees were used to determine the probability of system failures. The fault trees developed for the risk assessment included basic component failures, instrumentation and control failures, support system failures, maintenance unavailabilities, operator errors, and common-cause errors.

Systems modeled as capable of cooling the spent fuel pools were the spent fuel pool cooling systems and the RHR systems in the spent fuel pool cooling assist mode. The RHR system in the shutdown cooling mode was not credited in the staff's analysis as being capable, in and of itself, of keeping the pools from reaching near boiling conditions, although it should be capable of preventing bulk boiling of the pools. PP&L has indicated to the staff that it has another path for cooling the spent fuel pools that involves a feed and bleed process with the emergency service water system (or fire water system) as the cold water "feed" to the spent fuel pools and outlets through the skimmer surge tank drain line or the cask pit drain line as "bleed" from the pools. An alternate "bleed" path is to pump water into the pools by either the emergency service water or fire water system, let the pools overflow into the drains on the 818' level, and bring in a portable pump(s) to remove the water from the lower levels of secondary containment to which the water would drain. None of these feed and bleed paths is proceduralized, and the staff did not specifically evaluate them or model them in its risk assessment.

The staff's event trees include a top event that acknowledges that the operators and the Technical Support Center (TSC) will have significant time (for many sequences, greater than 50 hours) to respond to loss of spent fuel pool cooling (SFPC) or to boiling of the spent fuel pools. It is the responsibility of the TSC to consider and develop innovative ways of solving problems, such as those of a boiling pool. The staff does not believe that it is possible to specifically model possible innovative recovery actions for each sequence. However, the staff does believe that the support of the TSC conservatively is worth an order of magnitude or more in incremental CDF reduction in events where boiling takes more than 50 hours to occur. Examples of possible TSC help include bringing in portable diesel generators, portable pumps, portable heat exchangers, or new transformers.

For both the as-fixed and as-found conditions, the human reliability analysis (HRA) methodology models human errors that can contribute to system failures or otherwise impact the sequence of events such that cooling to the SFP(s) is not recovered. Important human actions are addressed in the values used in the top event of the event trees based on a simplified approach for the treatment of human errors. The staff modeled proceduralized actions performed in response to evolving plant conditions as critical actions and quantified them following guidance from the Accident Sequence Evaluation Program (ASEP) provided in NUREG/CR-4772 (Ref. 24). The staff modeled longer-term actions that involve repair, innovative recovery, or non-routine time-consuming system line-ups (i.e., placing RHR in the SFPC assist mode of operation) as recovery actions. These actions were quantified based on ASEP guidance and estimations from NUREG/CR-4550 in Appendix C, Section C.5, "Issue 5," Innovative Recovery Actions for Long-Term Sequences Involving Loss of Containment Heat Removal" (Ref. 25). These techniques lead to human-error probabilities generally in the range of 0.004 to 0.01 for restart-related actions and generally in the range of 0.1 to 0.5 for repair or recovery actions.

In order to effectively estimate the NBF, the staff broke the operation of the Susquehanna units into various cases depending on the time to boil and the equipment required to keep the pools from boiling. There are four cases for the as-fixed units (the state of the SSES units as they exist today) and five cases for the as-found units (as the units existed at the time that the concerns about loss of cooling to the spent fuel pools were initially identified around 1991). Tables 5.B and 5.C list the plant conditions (and acceptance criteria) that define each of the cases for the as-fixed and as-found conditions, respectively. The staff estimated the near boiling frequency (NBF) and the incremental core damage frequency (CDF) for sequences associated with the cases above for each initiating event.

In the as-found evaluation, there were five cases. Cases 1 and 2 are for sequences that take more than 50 hours to boil. Cases 3 and 4 evaluated sequences that take between 25 to 50 hours to boil the spent fuel pools. Case 5 covered the specific case where time-to-boil was between 15 and 25 hours. This case involved more stressful conditions than the others and therefore included larger human error probability (HEP) values. The as-fixed condition considered cases 1 and 2 that take more than 50 hours for the spent fuel pools to boil. Cases 3 and 4 for the as-fixed condition model sequences that take between 25 and 50 hours to boil. In the as-fixed condition, there is no Case 5 since there are no sequences that take less than 25 hours to bring the spent fuel pools to boil. Differences do exist between the HEP values used in the as-found and as-fixed conditions. These differences are due to improved procedures, improved operator awareness, and sometimes (e.g., SFP level) improved indications for the operators in the as-fixed condition.

There are a number of modeling differences between the as-fixed and as-found models used in Phases I and II of the risk assessment. These differences include the following:

(1) In the as-fixed models, spent fuel pools are cross-connected (i.e., the gates that could separate the pools have been removed) for the entire operating cycle, except as may be necessary for some off-normal or emergency situation. This results in the following:

a) the as-fixed failure sequences always result in two pools boiling,

b) the as-fixed NBF event trees (ETs) are different than those in the as-found model, and

c) the as-fixed model has no "isolated system"-related basic events. All basic events are combined.

(2) In the as-fixed models, there is improved operator recognition of SFP conditions due to improved indication in the control room.

(3) Procedures exist today and are in the as-fixed models for placing the RHR system in the SFPC assist mode (the procedure requires operators to raise the SFP level before running the RHR system in the SFPC assist mode). This improves the HEP values.

(4) Loss of offsite power (LOOP) off-normal procedures exist today that prompt the operators to restore cooling to the spent fuel pools (In the as-found condition, this procedure has no prompt). This improves the HEP values.

(5) Administrative procedures exist today and are in the as-fixed models that maintain the units in a configuration where there is at least 25 hours to SFP boiling upon a loss of SFPC. This results in the elimination of case 5 in the as-fixed models.

Phase II of the risk assessment evaluated the consequences of having spent fuel pool(s) boiling. The equipment in the reactor building providing cooling to the reactor core should not be adversely affected by loss of cooling to the spent fuel pool unless the energy released in the form of increased temperature and humidity conditions spreads throughout the reactor building. The energy released from the surface of the SFP after loss of SFPC prior to SFP boiling conditions would be kept from spreading to the reactor building by normal Zone 3 HVAC systems (when operating), by the standby gas treatment system (SGTS) (when operating), and by isolating the recirculation fans (if operating). The effectiveness of these systems at preventing spread of the steam from the SFP surface to the reactor building is decreased and not credited after near boiling conditions have developed.

The secondary containment isolation signals for the reactor building of a unit that is in a refueling outage are bypassed to maintain secondary containment integrity for the operating unit and the refueling floor. This action would prevent the spread of steam from Zone 3 to the refueling unit's reactor building. Because the reactor building of the unit in refueling would be outside of the isolated portions of secondary containment for all initiating events, the rector building of the operating unit would experience temperature

increases at an increased rate after the SFP(s) begin to boil when both the operating unit and refueling floor zones are within the isolated portion of secondary containment.

Near boiling conditions in the SFP(s) would not develop prior to 15 hours after the initiating event for the largest heat load conditions associated with case 5 in the as-found condition. The time to near boiling conditions for cases 3 and 4 is between 25 and 50 hours for both as-fixed and as-found conditions. The time to boil for cases 1 and 2 is greater than 50 hours for both the as-fixed and as-found conditions. The reactor core would not be adversely impacted from the consequences of an event that leads to loss of SFPC unless the ECCS equipment that had not completed its safety functions were rendered inoperable due to adverse room environmental conditions. Failure of ECCS equipment is not expected to occur until at least eight hours after the onset of near boiling conditions in the SFP(s).

In Phase II the staff estimated the incremental core damage frequency associated with spent fuel pool boiling events that passed the screening criteria above. The core damage estimate is incremental because the estimate does not include sequences that would go to core damage independent of boiling in the pool (e.g., long-term station blackout or a very large seismic event). The timing associated with the sequences that passed the screening criteria is approximate and indicates the depth of plant response that can be used by the operators to prevent core damage. The timelines that reflect these sequences show the systems that likely would be used to mitigate the event. The risk assessment provides an order of magnitude estimation of the incremental core damage frequency associated with these sequences.

Because of recent PP&L commitments, the spent fuel pools are always cross-connected and are so reflected in the as-fixed model. For the as-fixed model, on entering Phase II the staff assumes that both spent fuel pools are already boiling. For the as-found model either one or two pools are boiling on entry to Phase II. The staff takes the conservative position in its risk assessment that emergency core cooling system (ECCS) equipment in secondary containment will fail if subject for a sufficiently long time to a steam environment. For purposes of the risk assessment, this period is assumed to be 8 hours after boiling begins. If cooling to the spent fuel pools is restored during the 8 hour period, the ECCS equipment is assumed to survive and operate satisfactorily so that no core damage occurs.

If the ECCS equipment fails, the risk assessment evaluates whether the Susquehanna operators can use equipment outside of secondary containment to provide core cooling. The credit for the mitigation capabilities of equipment outside of containment has not been systematically evaluated as would be done for a full probabilistic risk assessment. However, the staff has made use of the Susquehanna IPE that does model the use of these systems. The staff used a semi-quantitative method based in part on expert opinion to estimate the benefit from these systems outside of secondary containment.

The Phase II evaluation considers whether the standby gas treatment system (SGTS) is running or is started by the operators, and whether the recirculation fan system is off or is shut off by the operators. If the SGTS

is on and the recirculation fans are shut off, the staff believes that the time to ECCS equipment failure in secondary containment would be extended by ten or more hours. However, due to the extended period (particularly in the as-fixed condition) before near pool boiling conditions would be reached, recovery rates are nearly identical whether or not the SGTS and recirculation fans are properly controlled by the operators.

Because of commitments made by PP&L to operate with its spent fuel pools cross-connected, the staff assumes that all as-fixed pool boiling events involve two pools boiling. For the as-found condition where the pools were isolated from each other most of the time, some sequences lead to two pools boiling and others only to one pool boiling. For two pools boiling, PP&L has reported [PP&L, 1994] that the standby gas treatment system (SGTS) could fail less than 17 hours after pool boiling begins, depending on the heat loads involved. Failure is assumed to be caused by structural failure of the SGTS piping due to the weight of the condensed steam. This failure is not modeled in the risk assessment.

5.3.2 Phase I - Near Boiling Frequency

Phase I of the risk assessment estimated the frequency with which events would cause a loss of cooling to the spent fuel pool(s) that lasted long enough for the pools to heat up and reach near pool boiling temperatures (i.e., bulk spent fuel pool temperature in the cooler pool > 170 °F or > 200 °F for an isolated pool). The assumptions modeled in the risk assessment are documented in Table 5.A of this SE. Tables 5.D and 5.E list the NBFs for each case and each initiating event for the as-fixed and as-found conditions, respectively. These cases (four for the as-fixed and five for the as-found conditions) were evaluated using appropriate SFP heat-load conditions, representative spent fuel pool configurations, and associated service water system inlet temperatures for the SSES SFPs. The NBF values do not include sequences where the pool takes more than 50 hours to boil. The staff believes this is appropriate because innovative mitigative resources, which were not modeled in the risk assessment, could be brought into play. Extended loss of offsite power and LOCA events are the most important initiators that lead to near boiling conditions, followed by shorter loss of offsite power events, flooding, and service water system pipe breaks. Based on the capability of other systems outside secondary containment (as discussed in Section 5.3.3), the staff believes that equipment outside of secondary containment provides additional mitigative protection reducing the conditional core damage frequency to a value several orders of magnitude below the associated NBF.

5.3.2.1 "As-Fixed"

The as-fixed NBF estimates reflect current conditions at the units including in-place plant off-normal and emergency operating procedures (EOPs), plant configurations that PP&L indicates are typical for various modes of operation for the two units, the minimum time it takes to remove fuel from the vessel, configuration control to maintain a minimum of 25 hours to pool boiling, and the timing when PP&L performs maintenance activities related to systems supporting spent fuel pool cooling.

For each initiating event considered, the SFP NBFs were estimated for the as-fixed state. Table 5.D shows the results of the analysis. The staff's realistic estimate for the total NBF for the as-fixed state is about $1x10^{-5}$ per year. If all sequences that would take more than 50 hours for the fuel pools to boil were included in the NBF total, the NBF would conservatively increase to about $2x10^{-5}$ per year.

There are several important reasons why the frequencies of the staff's as-fixed NBF estimates are so low for this event at the Susquehanna units. These include the following:

- the operation of the Susquehanna units with the spent fuel pools cross-connected (i.e., water can freely communicate between the pools), which significantly extends the time to pool boiling. This is the most important modification made by PP&L to the SSES units to minimize the effects of loss of spent fuel pool cooling,

- configuration control by PP&L that helps to assure that the units will be configured such that pool boiling will not occur in less than 25 hours following loss of cooling to the pools, and

- improved off-normal and emergency procedures at Susquehanna.

For cases 3 and 4 of the as-fixed condition, extended loss of offsite power (LOOP), LOOP, and LOCA with LOOP sequences passed the screening criteria for important sequences potentially leading to core damage. The largest contributors to NBF were the extended LOOP events for both case 3 and 4. The LOCA sequences had similar contributions. All other sequences have estimated NBF totals for all cases below $1x10^{-6}$ per year or take more than 50 hours to boil the spent fuel pools. See Table 5.D for a complete list of estimated as-fixed NBFs.

5.3.2.2 "As-Found"

The as-found NBF estimates reflect the instrumentation available to the operators, the procedures in place at the time, the level of operator awareness of the importance of not allowing the pools to boil, the fact that spent fuel pools normally were not cross-connected, the plant configurations applicable to earlier refueling outages, and maintenance timing.

For each initiating event considered, the SFP NBFs were estimated for the as-found state. Table 5.E shows the results of the analysis. The staff's realistic estimate for the total NBF for the as-found state is about $4x10^{-5}$ per year. If sequences where the fuel pools would take more than 50 hours to boil were included, the NBF would conservatively increase to about $7x10^{-5}$ per year.

For cases 3, 4, and 5 of the as-found condition, there are about 10 pool boiling sequences that pass the screening criteria for important sequences potentially leading to core damage. These include cases 3 through 5 for the extended loss of offsite power (LOOP) initiator, cases 3 through 5 for the LOCA events, and cases 3 through 5 of the shorter duration loss of offsite power events. All other sequences have estimated NBFs below $1x10^{-6}$ per year or take more than 50 hours to boil the spent fuel pools. See Table 5.E for a complete list of estimated as-found NBFs.

5.3.3 Phase II - Core Damage Frequency

The staff used a qualitative approach to evaluate the potential for the most important event sequences to result in damage to the reactor core. In the discussion below the staff describes the timelines associated with the event sequences. The timelines identify the major events and activities that occur or would be likely to occur from the onset of the event to the point where failure to mitigate the event could lead to core uncovery. The timelines associated with these events and activities are approximate and indicates the depth of resources that can be applied in the plant response given the long time periods prior to core uncovery. The systems that are likely to be used to mitigate each event are identified and grouped into categories. The categories are based on equipment location and functions. Given near boiling conditions, conservative order-of-magnitude failure probabilities are assigned for overall combined system capabilities for these categories of systems. The staff multiplied the order-of-magnitude conditional failure probabilities by the estimated NBF for the event sequences analyzed to yield an estimation of the incremental contribution to the core damage probability from the initiating event. The results from this evaluation for each event sequence evaluated are summed to obtain the overall contribution to core damage frequency from events causing a loss of SFPC. The magnitude of the results provides an indication of the relative significance of these events in relation to other contributors to core damage.

The staff concentrated on the mitigative properties of those systems outside of secondary containment that would not be subject to the potentially harsh environmental conditions following a spent fuel pool boiling event and that can provide injection to the core. The staff did not attempt to determine the conditional failure probability of equipment that would be inside secondary containment in a steam environment, due to a lack of realistic data. PNL provided a supporting evaluation [PNL, 1994] that details the estimation of incremental CDF.

Events that cause a loss of SFPC and subsequent system failures, and human errors that lead to near boiling conditions in the SFP(s) do not present an immediate threat to the fuel in the SFPs or to the ability of operators to maintain core cooling to the reactor. The SFP would have to essentially boil dry before the spent fuel in the SFPs would present any radiological threat offsite. This event has been evaluated in NUREG/CR-4982 (Ref. 26) (see also Section 5.2). The equipment in the reactor building providing cooling to the reactor core is not adversely affected by loss of cooling to the SFPs unless the energy released from the SFPs in the form of increased temperature and humidity conditions spreads into the reactor building. The energy released from the surface of the SFPs after a loss of SFPC prior to SFP boiling conditions will be kept from spreading to the reactor building by normal Zone 3 HVAC systems (when operating), or by operating the SGTS and securing the recirculation fans (if one or more zones are isolated). The effectiveness of these systems at preventing spread of the steam from the SFP surface to the reactor building is decreased and not credited after near boiling conditions have developed.

The secondary containment isolation signals for the reactor building of a unit that is in a refueling outage are bypassed to maintain secondary containment integrity for the operating unit and the refueling floor. This action would prevent the spread of steam from Zone 3 to the refueling unit's reactor building. Because the reactor building of the unit in refueling would be outside of the isolated portions of secondary containment for all initiating events, the rector building of the operating unit would experience temperature increases at an increased rate after the SFP(s) begin to boil when both the operating unit and refueling floor zones are within the isolated portion of secondary containment. The risk assessment conservatively models that temperatures adverse to equipment operation could be reached in emergency core cooling system equipment rooms (of the operating unit) within eight hours after pool boiling begins.

The reactor core would not be adversely effected by a loss of SFPC event unless ECCS equipment that have not completed their safety functions were rendered inoperable due to the steam environment. As described above, this is not expected to occur until at least eight hours after the onset of near boiling conditions in the SFP(s). The fastest time to near boiling conditions was estimated to have been 15 hours after a case 5 initiating event (largest heat load conditions) in the as-found plant condition. The time to near boiling conditions for cases 3 and 4 between 25 and 50 hours for both as-found and as-fixed plant conditions. The time to SFP near boiling conditions for cases 1 and 2 is greater than 50 hours for both the as-found and as-fixed plant conditions. These time to near boiling conditions are presented in Tables 5.B and 5.C.

The staff evaluated the most important event sequences to identify a bounding order-of-magnitude range for failures. The staff chose to group the system in the following categories:

(1) systems and operator actions that could be used to prevent excessive steaming release to the reactor building

(2) normal ECCS equipment and any necessary operator actions in the reactor building

(3) back-up equipment located in the other unit's reactor building or located outside the reactor building that could be connected and aligned to provide reactor core cooling

The success of any of these categories of systems is heavily dependent on operator actions. The order-of-magnitude ranges and selected values for the likelihood of failure associated with these categories of equipment are estimated based on the consideration of several factors that effect their success. These considerations are generally human action performance shaping factors. The factors considered in judging the likely failure range and selecting equipment category failure values include the following:

(1) the number of systems and amount of equipment available that could perform the required function

(2) the degree of perceived importance to plant operators and TSC staff

(3) the dynamic significance of the event sequence with associated competing interests for the operator's attention

(4) the degree of dependence among the human actions taken

(5) the approximate time available to complete the action

(6) the indications available to the operators or TSC staff regarding plant conditions

(7) the degree and completeness of procedural guidance

(8) the overall plant damage state for the event sequence

5.3.3.1 "As-Fixed"

The as-fixed evaluation models the current configuration of the spent fuel pools and their interfacing systems and takes into account current operating procedures and practices identified by PP&L.

Phase II "As-Fixed" Results and Insights

There are several sequences for the as-fixed state that pass the criteria for identifying important sequences: extended loss of offsite power, cases 3 and 4; LOCA, cases 3 and 4; LOCA with LOOP, case 3; and LOOP, case 3.

In the narratives below, the staff describes for cases 3 and 4 how the Susquehanna units are expected to respond to various initiators. The narratives describe major events and activities that would be likely to occur from the onset of the event to the point where failure to mitigate the event could lead to core uncovery. In Figure 5.A and 5.B, the staff displays timelines that depict how the Susquehanna units and the operators are modeled in the risk assessment to respond to various initiators for cases 3 and 4 in the as-fixed condition. Table 5.F lists the core damage frequency estimates for as-fixed initiators and cases that pass the screening criteria.

EVENT SEQUENCE EVALUATION: EVENTS OCCURRING IN CASE 3 AS-FIXED PLANT CONDITIONS (See Figure 5.A for timeline representation of this sequence).

This narrative describes the events that are postulated to occur in the risk assessment in case 3 (See Table 5.B that defines the as-fixed cases) and that pass the screening criteria. Because of the similarity of progression of events within a case, all as-fixed case 3 sequences are described in this narrative. When warranted, the narrative notes sequence differences.

Initial Plant Conditions

The plant's initial conditions are as follows: Unit 1 is being refueled with the core off-loaded into the SFP, the Unit 1 SFPC system is out of service for maintenance, and the Unit 1 RHR system is out of service for maintenance (i.e., no SFPC is or can be provided by Unit 1). the Unit 1 and Unit 2 SFPs are cross-connected. Unit 2 is at normal operating conditions, the Unit 2 SFPC system is inservice with three SFPC pumps running, and the Unit 2 RHR system has one train available for operation in the SFPC assist mode (unless there is a LOCA in Unit 2).

From Initiating Event To Near Boiling Condition In The SFPs

The initiating event occurs at time zero. LOOP, extended LOOP, and LOCA with LOOP cause a complete loss of offsite power to both units. LOCA and LOCA with LOOP involve a large, medium, or small break LOCA in the operating unit. A LOCA in the operating unit will cause loss of SFPC and cause RHR of the LOCA unit to be unavailable for the SFPC assist mode (based on PP&L commitment). Coincident with all these initiators, Unit 2 scrams and the SGTS and the recirculation system automatically start. Plant operators respond to the event in accordance with off-normal/emergency procedures and the TSC is assumed to be activated within one hour after the initiating event. Note that for as-fixed plant conditions, the LOOP off-normal procedures provide a prompt for operators to ensure that SFPC is returned to service. Operators at both units continue with emergency actions after the initiating event and at 1 hour, operators recognize the need to restore cooling to the SFPs. If offsite power is not restored to the plant within 4 hours, the risk assessment considers the LOOP to be "extended". Operators align systems to emergency power supplies as needed in accordance with the emergency procedures. The TSC remains activated and operators successfully respond to emergency plant actions for the extended LOOP. Within 5 hours after the LOOP, the operators and TSC may decide to use any surplus capacity available from the EDGs to power non-safety buses to support operation of the SFPC system including the service water system that supports the SFPC heat exchangers. If power becomes available to the non-safety bus for the Unit 2 SFPC system, operators would attempt to restart the Unit 2 SFPC system or return the Unit 1 SFPC system to service. Alternatively, the operators would align any available train of RHR from Unit 1 or Unit 2 for operation in the SFPC assist mode as necessary to restore cooling to the SFPs. Within 8 hours, the operators or TSC may attempt to provide SFP cooling by alternate means such as emergency service water (ESW), diesel backed fire water, pumper truck, or other feed and bleed cooling alignments. These actions would continue persistently as the SFPs continued to heat up and approach near boiling conditions. Offsite power may be recovered later, within 10 hours or within 20 hours after the LOOP. The SFPs would reach near boiling conditions (approximately 170°F) about 25 hours after the initiator assuming that operators at both units do not restore SFPC to service.

From Near Boiling Conditions In The SFPs To Core Uncovery

Without restoration of cooling to the SFPs within 25 hours after the initiator, the SFPs would reach near boiling conditions causing an increased rate of steam release from the surface of the SFP. Under SFP boiling conditions, the rate of steam release to Zone 3 would exceed the capacity of the normal HVAC system and the SGTS for removal of this energy. If the recirculation system were left running, the steam would spread to the reactor building. Approximately eight hours after the SFPs reach near boiling conditions (33 hours after the initiator), the steam spread to the reactor building is assumed to cause ECCS equipment failure due to an adverse room environment. The operators and TSC would make every effort to provide core cooling using any available means including the following:

- any surviving Unit 2 ECCS equipment (this was not modeled in the risk assessment),

- ECCS equipment from Unit 1 that could be cross-connected to Unit 2 given that the Unit 1 reactor building was isolated from Zone 3 for refueling conditions (this was not modeled in the risk assessment), or

- equipment outside the reactor building of Unit 1 or Unit 2 such as standby liquid control, reactor water cleanup, fire water, control rod drive maximized, RHR service water, or pumper truck.

Most of these alternate cooling mechanisms are identified in the emergency procedures. The reactor core would begin to uncover at approximately 36 hours after the initiator if all these actions related to restoration of cooling to the SFPs with alternate cooling methods, isolation of Zone 3 air space, and restoration of core cooling to Unit 2 were to fail.

The event tree presented in Figure 5.A illustrates the sequence flow path that could lead to core damage given near boiling conditions from the case 3 initiating event. The general functional failures that would have to occur before the sequence could reach a core damage end state and order of magnitude estimations of their failure likelihoods are as follows:

- Failure of alternate methods for cooling the SFPs that were not credited in the estimation of the NBF as well as failure of operators to isolate Zone 3 from the Unit 2 reactor building within approximately 33 hours after the initiator. The failure occurs if operators do not implement alternate feed and bleed cooling to the SFPs using one of at least three possible systems and also do not isolate the Zone 3 air space from Zone 2 air space. The likelihood that these actions would fail given approximately 25 hours between exceeding the SFP temperature technical specification limit and failure of ECCS equipment in Unit 2 is estimated at 0.1.

- Failure of and non-recovery of all Unit 2 ECCS equipment that would normally be capable of providing sufficient long term decay heat removal given the initial short term post scram functions are completed prior to failure of the ECCS equipment. The likelihood that these actions would fail given the plant conditions, time frame and plant staff involved, and level of other activities is estimated at 1.0.

- Failure of all equipment outside the Unit 2 reactor building including ECCS equipment from Unit 1 that could be cross-connected to Unit 2 or equipment outside the reactor building of Unit 1 or Unit 2 such as condensate, feedwater, standby liquid control, reactor water cleanup, fire water, control rod drive maximized, RHR service water, or pumper truck. Most of these alternate cooling mechanisms are identified in the emergency procedures. The likelihood that these action would fail given the plant conditions, time frame and plant staff involved, and level of other activities is estimated at 0.01.

The overall order of magnitude estimate of the conditional core damage frequency due to a initiating event in case 3 is the product of the estimated NBF and the three general functional failure estimations above. These estimates are given in Table 5.F.

EVENT SEQUENCE EVALUATION: EVENTS OCCURRING IN CASE 4 AS-FIXED PLANT CONDITIONS (See Figure 5.C for timeline representation of this sequence).

This narrative describes the events that are postulated to occur in the risk assessment in case 4 (See Table 5.B that describes the as-fixed cases) and that pass the screening criteria. Because of the similarity of progression of events within a case and between case 3 and 4, all as-fixed case 4 sequences are described in this narrative and only differences to case 3 are noted.

Initial Plant Conditions

The plant's initial conditions are as follows: Unit 1 is being refueled with the core off-loaded into the SFP, the Unit 1 SFPC system is in service, and the Unit 1 RHR system has two trains available for SFPC assist mode (In case 3, the Unit 1 SFPC system and RHR system are out of service). The Unit 1 and Unit 2 SFPs are cross-connected. Unit 2 is at normal operating conditions, the Unit 2 SFPC system is inservice each with three SFPC pumps running, and the Unit 2 RHR system has one train available for operation in the SFPC assist mode.

From Initiating Event To Near Boiling Condition In The SFPs

Initiating event conditions and their descriptions are identical to case 3, as-fixed plant conditions provided above.

From Near Boiling Conditions In The SFPs To Core Uncovery

The events expected to occur between near boiling and core uncovery are essentially the same for cases 3 and 4. The biggest differences between the cases involve less equipment being available to cool the pools in case 3, different minimum equipment configurations needed to mitigate the pool boiling based on SFP heat load differences and the durations to pool boiling. The overall order of magnitude estimate of the conditional core damage frequency due to a initiating event in case 4 is the product of the estimated NBF and the three general functional failure estimations above. These estimates are given in Table 5.F.

5.3.3.2 "As-Found"

The as-found evaluation models the configuration of the spent fuel pools and their interfacing systems as they existed when the spent fuel pool concerns were discovered and takes into account the operating procedures and practices identified by PP&L as being in place at that time.

Phase II "As-Found" Results and Insights

There are a number of sequences for the as-found state that pass the criteria for identifying important sequences: extended loss of offsite power, cases 3 through 5; LOCA, cases 3 through 5; LOOP, cases 3 through 5; and LOCA with LOOP, case 3.

In the narratives below, the staff describes for cases 3 and 4 how the Susquehanna units are expected to respond to various initiators. The narratives describe major events and activities that would be likely to occur from the onset of the event to the point where failure to mitigate the event could lead to core uncovery. In Figures 5.D, 5.E, and 5.F, the staff displays timelines that depict how the Susquehanna units and the operators are modeled in the risk assessment to respond to various initiators for cases 3 and 4 in the as-found condition. Table 5.G lists the core damage frequency estimates for as-found initiators and cases that pass the screening criteria.

EVENT SEQUENCE EVALUATION: EVENTS OCCURRING IN CASE 3 AS-FOUND PLANT CONDITIONS (See Figure 5.E for timeline representation of this sequence).

This narrative describes the events that are postulated to occur in the risk assessment in case 3 (See Table 5.C that describes the as-found cases) and that pass the screening criteria. Because of the similarity of progression of events within a case, all as-fixed case 3 sequences are described in this narrative. When warranted, the narrative notes sequence differences.

Initial Plant Conditions

The plant's initial conditions are as follows: Unit 1 is being refueled with the core off-loaded into the SFP, the Unit 1 SFPC system is out of service for maintenance, and the Unit 1 RHR system is out of service for maintenance (i.e., no SFPC is or can be provided by Unit 1). the Unit 1 and Unit 2 SFPs are cross-connected. Unit 2 is at normal operating conditions, the Unit 2 SFPC system is inservice with three SFPC pumps running, and the Unit 2 RHR system has one train available for operation in the SFPC assist mode (unless there is a LOCA in Unit 2).

From Initiating Event To Near Boiling Condition In The SFPs

The initiating event occurs at time zero. LOOP, extended LOOP, and LOCA with LOOP cause a complete loss of offsite power to both units. LOCA and LOCA with LOOP involve a large, medium, or small break LOCA in the operating unit (assumed to be Unit 2). This results in loss of SFPC and causes RHR of the LOCA unit to be unavailable for the SFPC assist mode. Coincident with all these initiators, Unit 2 scrams and the SGTS and the recirculation system automatically start. Plant operators respond to the event in accordance with

off-normal/emergency procedures and the TSC is assumed to be activated within one hour after the initiating event. Note that for as-found plant conditions, the LOOP off-normal procedures did not prompt operators to ensure SFPC is returned to service. Operators at both units continue with emergency actions for these events. Offsite power is restored within four hours for the LOOP event and after restoration of offsite power, operators return systems to their normal alignments. Operators of Unit 2 may attempt to perform a rapid restart of the plant within the first 6 hours after a LOOP. The TSC would deactivate by 6 hours after the LOOP based on recovery of offsite power and operator's successful handling of emergency plant actions for the LOOP. For the extended LOOP, LOCA, or LOCA with LOOP events, the TSC would not be deactivated during the event as mitigation activities continue.

For all these event sequences, the SFPs would reach the technical specification limit of 125°F at approximately 8 hours after the initiator assuming that operators at both units do not restore SFPC to service. Operators are trained to comply with technical specifications, therefore at or near 8 hours after the initiator the operators would recognize the need to restore cooling to the SFPs. At 8 hours after the initiator, the operators would attempt to use the available systems to return cooling to the SFPs. This would involve attempting to restart the Unit 2 SFPC system, return the Unit 1 SFPC system to service, or align a train of RHR from Unit 1 or Unit 2 for operation in the SFPC assist mode to restore cooling to the SFPs, as system availability (including ac power) allows. These actions would continue persistently as the SFPs continued to heat up and approach near boiling conditions. Within 10 to 20 hours after the initiator, the operators may attempt to provide SFP cooling by alternate means such as ESW, Fire Water, Pumper Truck, or other feed and bleed cooling alignments.

From Near Boiling Conditions In The SFPs To Core Uncovery

Without restoration of cooling to the SFPs within 25 hours after the initiator, the SFPs would reach near boiling conditions causing an increased rate of steam release from the surface of the SFP. Under SFP boiling conditions, the rate of steam release to Zone 3 will exceed the capacity of the normal HVAC system and the SGTS for removal of this energy. If the recirculation system is left running, the steam spreads to the reactor building. Approximately eight hours after the SFPs reach near boiling conditions (33 hours after the initiator), the steam's spread to the reactor building is assumed to cause ECCS equipment failure due to adverse temperature conditions. If the TSC were deactivated (LOOP event), it would be reactivated at about 33 hours after the LOOP based on ECCS equipment failures. If Unit 2 were restarted earlier, it scrams or operators perform a controlled shutdown due to ECCS equipment failures. The operators and TSC would make every effort possible to provide core cooling using any available means including the following:

- any surviving Unit 2 ECCS equipment (not modeled in the risk assessment,

- ECCS equipment from Unit 1 that could be cross-connected to Unit 2 given that the Unit 1 reactor building was isolated from Zone 3 for refueling conditions (not modeled in the risk assessment), or

- equipment outside the reactor building of Unit 1 or Unit 2 such as feedwater, condensate, standby liquid control, reactor water cleanup, fire water, control rod drive maximized, RHR service water, or pumper truck.

Most of these alternate cooling mechanisms are identified in the emergency procedures. The reactor core would begin to uncover at approximately 36 hours after the initiator if all these actions related to restoration of cooling to the SFPs with alternate cooling methods, isolation of Zone 3, and restoration of core cooling to Unit 2 were to fail.

Order Of Magnitude Estimation Of Conditional Core Damage Frequency Given The Initiator In Case 3 Conditions

The event tree presented in Figure 5.A presents the sequence flow path that could lead to core damage given near boiling conditions from the case 3 initiating event. The general functional failures that would have to occur before the sequence could reach a core damage end state and order of magnitude estimations of their associated failure likelihoods are as follows:

- Failure of alternate methods for cooling the SFPs that were not credited in the estimation of the NBF as well as failure of operators to isolate Zone 3 from the Unit 2 reactor building within approximately 33 hours after the initiator. The failure occurs if operators do not implement alternate feed and bleed cooling to the SFPs using one of at least three possible systems and also do not isolate the Zone 3 air space from Zone 2 air space. The likelihood that these actions would fail given approximately 25 hours between exceeding the SFP temperature technical specification limit and failure of ECCS equipment in Unit 2 is estimated at 0.1.

- Failure of and non-recovery of all Unit 2 ECCS equipment that would normally be capable of providing sufficient long term decay heat removal given the initial short term post scram functions are completed prior to failure of the ECCS equipment. The likelihood that these actions would fail given the plant conditions, time frame and plant staff involved, and other activities is estimated at 1.0.

- Failure of all equipment outside the Unit 2 reactor building including ECCS equipment from Unit 1 that could be cross-connected to Unit 2 or equipment outside the reactor building of Unit 1 or Unit 2 such as feedwater, condensate, standby liquid control, reactor water cleanup, fire water, control rod drive maximized, RHR service water, or pumper truck. Most of these alternate cooling mechanisms are identified in the emergency procedures. The likelihood that these actions would fail given the plant conditions, time frame and plant staff involved, and other activities is estimated at 0.01.

The overall order of magnitude estimate of the conditional core damage frequency due to an initiating event in case 3 is the product of the estimated

NBF and the three general functional failure estimation above. The product of these values and the near boiling frequencies, which give one an estimated incremental core damage frequency, are given in Table 5.G.

EVENT SEQUENCE EVALUATION: EVENTS OCCURRING IN CASE 4 AS-FOUND PLANT CONDITIONS (See Figure 5.E for timeline representation of this sequence).

This narrative describes the events that are postulated to occur in the risk assessment in case 4 (See Table 5.C that describes the as-found cases) and that pass the screening criteria. Because of the similarity of progression of events within a case, all as-fixed case 4 sequences are described in this narrative. When warranted, the narrative notes sequence differences.

Initial Plant Conditions

The plant's initial conditions are: Unit 1 is being refueled with the core off-loaded into the SFP, and Unit 1 has two trains of RHR available for operation in the SFPC assist mode. The Unit 1 and Unit 2 SFPs are isolated. The Unit 1 SFPC system and Unit 2 SFPC system are both inservice, each with three SFPC pumps running. Unit 2 is at normal operating conditions, and Unit 2 has one train of RHR available for operation in the SFPC assist mode. In case 3, as-found condition, Unit 1's SFPC system and RHR system are out of service.

From Initiating Event To Near Boiling Condition In The SFPs

Initiating event conditions and their descriptions are identical to case 3, as-found plant conditions provided above.

From Near Boiling Conditions In The SFPs To Core Uncovery

The events expected to occur between near boiling and core uncovery are essentially the same for cases 3 and 4, as-found. The biggest differences between the cases involve less equipment being available to cool the pools in case 3, different minimum equipment configurations needed to mitigate the pool boiling based on SFP heat load differences, and the durations to pool boiling. The overall order of magnitude estimate of the conditional core damage frequency due to a initiating event in case 4 is the product of the estimated NBF and the three general functional failure estimations above. These estimates are given in Table 5.G.

Order Of Magnitude Estimation Of Conditional Core Damage Frequency Given The Case 4 Initiator

The staff's estimation of conditional core damage frequency for the case 4, as-found initiator is developed that in the same manner as for case 3. Refer to case 3, as-found initiator above for additional details. The estimated core damage frequencies for the case 4 initiators are given in Table 5.G.

EVENT SEQUENCE EVALUATION: EVENTS OCCURRING IN CASE 5 AS-FOUND PLANT

CONDITIONS (See Figure 5.E for timeline representation of this sequence).

This narrative describes the events that are postulated to occur in the risk assessment in case 5 (See Table 5.C that describes the as-found cases) and that pass the screening criteria. Because of the similarity of progression of events within a case, all as-fixed case 5 sequences are described in this narrative. When warranted, the narrative notes sequence differences.

Initial Plant Conditions

Case 5 initial conditions are the same as case 4, as-found.

From Initiating Event To Near Boiling Condition In The SFPs

The description of case 5, as-found events is similar to that of case 4 events, but the time available for operator action and the time to near boiling conditions are shorter. For all the case 5 events, the SFPs would reach the technical specification limit of 125°F at approximately 5 hours (instead of 8 hours for case 4) after the initiator assuming that operators at both units do not restore SFPC to service. Operators would recognize the need to restore cooling to the SFPs. The operators would then attempt to use the available systems to return cooling to the SFPs.

From Near Boiling Conditions In The SFPs To Core Uncovery

Without restoration of cooling to the SFPs within 15 hours (rather than 25 hours for case 4) after the initiator, the SFPs would reach near boiling conditions causing an increased rate of steam release from the surface of the SFP. Within 20 hours after a LOOP initiator, there is the possibility for a very late recovery of offsite power. Approximately eight hours after the SFPs reach near boiling conditions (23 hours after the initiator), the steam spread to the reactor building is assumed to cause ECCS equipment failure due to adverse environmental conditions. The operators and TSC would make every effort possible to provide core cooling using any available means including those discussed for case 4, as-found above. The reactor core would begin to uncover at approximately 26 hours (versus 36 hours for case 4, as-found) after the initiator if all these actions related to restoration of cooling to the SFPs with alternate cooling methods, isolation of Zone 3 air space, and restoration of core cooling to Unit 2 were to fail.

Order Of Magnitude Estimation Of Conditional Core Damage Frequency Given The Case 5 Initiator

The event tree presented in Figure 5.A presents the sequence flow path that could lead to core damage given near boiling conditions from the case 5 initiating event. The general functional failures that would have to occur before the sequence could reach a core damage end state are the same as for case 4, as-found above. The overall order of magnitude estimate of the conditional core damage frequency due to an initiating event in case 5 is the product of the estimated NBF and the three general functional failure estimation above. This product is given in Table 5.G.

Table 5.A Modeling Assumptions for the Susquehanna Loss of SFPC Risk Assessment

ANALYSIS ASSUMPTIONS

AS-FOUND ASSUMPTIONS

The assumptions for the "As-Found" condition are listed below.

1. Spent fuel pools (SFP) are not initially cross-connected (i.e., gates are installed separating the SFPs) except Case 3 in which the SFPs are assumed to be initially cross connected.

2. The SFPs are successfully cooled when the temperature in the SFP with the higher decay heat load does not exceed 200°F for an isolated SFP, or this temperature does not exceed 170°F when the SFPs are cross-connected.

3. The heat removal capability of two or three Spent Fuel Pool Cooling (SFPC) pump and heat exchanger loops is assumed to be two or three times that of one pump and heat exchanger loop, respectively.

4. The heat load off-loaded to the SFP is such that the SFPC system can maintain the temperature in the SFP within the administrative limit of 115°F. SSES management maintains this limit by controlling the following: the number of SFPC pumps and heat exchangers on line, the time of the year the refueling is performed (which impacts the Service Water System (SWS) temperature and associated SFPC heat exchanger capacity), the amount of fuel off-loaded, the timing after shutdown of core off-load, the water volumes connected to the SFPs, and use of RHR in the SFPC assist mode if necessary (i.e., outage with full core off-load under summer conditions).

5. The heat load admitted to the SFP and pool configurations are controlled such that the time-to-boil after a loss of SFPC is greater than 25 hours. However, in the past, pool configurations may have been such that time-to-boil could have been between 15 and 25 hours for up to 10 days.

6. The operating cycle for a SSES unit is assumed to be 18 months and the duration of the refueling outage from unit shutdown to startup is assumed to be 75 days.

7. The Residual Heat Removal (RHR) system of each unit is assumed to have one train dedicated to reactor core decay heat removal for the following initiating events: LOOP, Extended LOOP, station blackout (SBO), LOCA with LOOP, and Seismic.

8. The RHR system for a unit that has a LOCA initiating event will not be available for SFPC assist mode.

9. The initiating event frequency for Loss of SFPC is assumed to include

the probability of the operator failing to perform immediate restart recovery actions.

10. During Case 2, the RHR system is assumed to have one train operating in the shutdown cooling mode. The other train is either aligned for shutdown cooling or out-of-service for maintenance. In both conditions, RHR is not available for SFPC assist mode operation. The RHR System will be in this latter condition for a total of eight days. When the RHR system is not in maintenance, one train is modeled as being available for SFPC assist to account for shutdown cooling operation providing cooling to the SFPs.

11. A thirty-day outage for SWS and/or RHR is assumed to occur each refueling outage after the core is off-loaded, the reactor cavity gates are reinstalled, and decay heat decreases to within the capability of 2 SFPC pump/heat exchangers (Case 3 Condition). Although this outage usually lasts only ten-days it is modeled for all of Case 3 (thirty-days) with the SFPC and RHR systems out-of-service on Unit 1 and the SFPs cross-connected. This is slightly more conservative than modeling the Unit 1 SFPC in service with the pools not cross-connected. This small conservatism in the model is based on the assumption that administrative controls do not limit the time the SFPC system is out-of-service.

12. Five Emergency Diesel Generators (EDGs) are installed at SSES any of which can be aligned to supply designated emergency loads or SFPC system loads for either Unit 1 or Unit 2. EDGs 1 through 4 are much harder to align to the SFPC system than is EDG 5. EDGs 1 through 4 must be backfed through safety busses, while EDG 5 can be directly aligned.

13. The SFPC system for one unit can provide adequate cooling for the SFP of the other unit when the gates separating both SFPs from the fuel shipping cask storage pool are removed. This cross-connected cooling arrangement requires a differential bulk water temperature between the SFPs of approximately 30°F to promote adequate water exchange. Additional SFPC system line-up alterations to provide forced delivery of cooling water to both SFPs are not required.

14. There are two building cranes that can remove the fuel shipping cask storage pool gates, and a qualified crane operator would be available within 2 hours of the time requested.

15. The fuel shipping cask storage pool is always maintained full of water.

16. Approximately eight hours are required to place the RHR system in the SFPC assist mode of operation.

17. There are two diesel fire pumps that can provide makeup to either Unit's SFP under SBO conditions.

18. The gates separating the reactor cavity from the SFP are provided with redundant positive-sealing devices and alarm features with alarm

indication of seal leakage and a low SFP level. Any significant loss of SFP inventory would require a concurrent major rupture of both independent sealing devices. This potential failure, as an initiating event for loss of SFPC, is not modeled since it is considered not credible.

19. The system and support system models used maintenance unavailability values representative of normal plant operations for all cases analyzed unless noted otherwise. Refueling outage and associated maintenance activities are assumed to be scheduled and performed such that these systems have availabilities comparable to normal operating conditions.

20. Equipment that is located in the reactor buildings (HVAC Zones 1 and 2) and is critical for performing safety functions will experience heatup after the onset of boiling in the SFP if not isolated from HVAC Zone 3. Successful isolation of HVAC Zone 3 requires that the recirculation system be shut off and the Standby Gas Treatment System (SGTS) be operating. When HVAC Zone 3 is not isolated, the safety equipment in HVAC Zones 1 and 2 reaches equipment failing critical temperatures approximately 8 hours after the onset of boiling in the SFP. During refueling outages, the reactor building for the unit being refueled is isolated from HVAC Zone 3 and therefore the safety equipment in that unit will not experience heatup from boiling in the SFPs. With the recirculation fans off, the SGTS would fail approximately 15 hours after the SFP begins to boil and the ECCS equipment would fail approximately 24 hours after the SFP begins to boil.

21. A reactor scram does not occur coincident with the loss of SFPC initiating event. Plant management is assumed to direct a plant shutdown at either the approximate time of onset-of-boiling in the SFP or when the area temperature in HVAC Zone 3 reaches 125°F, whichever occurs first.

22. A reactor scram occurs coincident with all initiating events except loss of SFPC. Safety functions begin at the time of the reactor scram as does the start of SFP heatup.

23. The condensate and feedwater systems have all their active components necessary for post-scram alignment feeding/makeup to the reactor pressure vessel located in the turbine building, and the turbine building does not experience heatup in response to SFP heatup. The condensate and feedwater systems are also assumed to be failed after a seismic event or loss of offsite power.

24. The flood, loss of SWS, and pipe break initiating event impacts are considered local events impacting only the SFPC equipment. Plant wide floods, loss of SWS, or pipe breaks with global effects as well as the potential for consequential damage to other safety-related equipment from these events was not considered.

25. Several other methods exist for backup SFPC that are not credited in the model. These methods would prevent SFP boiling or delay the time to SFP boiling conditions and include the following:

   - Feed and bleed to SFPs. Feed is provided through Emergency Service Water (ESW) (hard piped and EDG backed) or using fire hose (requires operators to run hose reel to SFPs or to hook up to ESW hard pipe). Bleed may be via the overflow through the SFP skimmer surge tank drain line or via the cask pit drain line.

   - Use the diesel-powered fire water pumps for discharge to the SFPs through connection to existing hard pipe systems (i.e., ESW).

   - Use of RHR in the shut down cooling mode of operation with discharge to the reactor pressure vessel (RPV) and simultaneously to the SFPs (although not proven to prevent SFP boiling, it certainly would delay the heatup).

26. Flooding to the reactor building from SFP condensate and/or overflow is directed to the reactor building sumps and this water is isolated from Emergency Core Cooling System (ECCS) equipment in the reactor buildings except one train of core spray.

27. The Technical Support Center (TSC) is manned and operational within one hour after the initiating event. The TSC staff will prepare appropriate recovery action procedures to support mitigation of the event.

28. SFP level and temperature indication in the control room was not improved.

29. The SGTS ductwork low points did not have drains.

30. The procedures for placing RHR in the SFPC assist mode did not require the operator to raise the SFP level before running the RHR system in the SFPC assist mode.

31. The LOOP emergency operating procedure did not prompt the operators to consider that the SFPC system needs to be restarted.

32. The administrative controls to maintain at least 25 hours to SFP boiling under a loss of SFPC were not formally controlled or documented.

33. The emergency procedures suggest a variety of ways to maintain core cooling in the event the ECCS systems failed, including the following: feedwater, condensate, CRD maximized, RHR-SWS cross-tie, fire water system, CRD from other unit, ECCS keep fill system, standby liquid control (SLC) boron tank, and SLC demineralized cross-tie.

34. Support system requirements are based on matrix information provided by SSES taken from the IPE.

35. The aluminum siding at some locations in the reactor building has hinged

panels that would pivot out and relieve pressure in the building due to the steam environment and thus help to remove energy and reduce temperature.

36. The response to any initiating event is successful when adequate SFPC is restored in time to prevent the SFP temperature from reaching 200°F.

AS-FIXED ASSUMPTIONS

The assumptions for the As-Fixed conditions differ from the As-Found conditions as outlined below.

1. Spent fuel pools are initially cross-connected (i.e., gates that could separate the SFPs have been removed) for the entire operating cycle except as may be necessary for some off-normal or emergency situation.

2. SFP level and temperature indication in the control room has been improved.

3. The procedures for placing RHR in the SFPC assist mode require the operator to raise the SFP level before running the RHR system in the SFPC assist mode.

4. The LOOP emergency procedure prompts the operators to restore cooling to the SFPC system.

5. The administrative controls to maintain at least 25 hours to SFP boiling under a loss of SFPC are formally controlled and documented. This may require use of RHR in the SFPC assist mode for a full core off load under summer conditions.

6. During the majority of the time the units are operating (cases 1, 2, and 3), the spent fuel pools only require a single SFPC system to cool both pools.

TABLE 5.B

DEFINITION OF "AS-FIXED" CASES

	Unit 2	Unit 1			
	All Cases	Case 1	Case 2	Case 3	Case 4
Plant Condition	Operating	Operating	Shutdown	Shutdown	Shutdown
Duration (normalized to 1 year) (hrs)	8766	6368	800	960	640
# Pumps initially running (SFP <115 °F)	1	1	1	2	3
# Pumps required (SFP <200 °F)	1	1	1	1	2
SFPC availability	Yes	Yes	Yes	No	Yes
RHR availability (# loops)	1	1	0-8 Days 1-17 Days	0	2
Time-to-Boil (hrs)	>50	>50	>50	>25	>25

TABLE 5.C

DEFINITION OF "AS FOUND" CASES

	Unit 2	Unit 1				
	All Cases	Case 1	Case 2	Case 3	Case 4	Case 5
Plant Condition	Operating	Operating	Shutdown	Shutdown	Shutdown	Shutdown
Duration (normalized to 1 year) (hrs)	8768	6368	800	960	320	320
# Pumps initially running (SFP <115 °F)	1	1	1	2	3	3
# Pumps required (SFP <200 °F)	1	1	1	1	2	2
SFPC availability	Yes	Yes	Yes	No	Yes	Yes
RHR availability (# loops)	1	1	0-8 Days 1-17 Days	0	2	2
Time-to-Boil (hrs)	>50	>50	>50	>25	>25	15 - 25

Table 5.D

NEAR BOILING FREQUENCY BY INITIATING EVENT
(As-Fixed Condition)

Initiator	Case 1	Case 2	Case 3	Case 4	Total
Loss of SFPC	1.1E-07	1.9E-08	5.0E-08	4.6E-08	2.3E-07
Loop	5.5E-07	7.9E-08	8.5E-07	4.6E-07	1.9E-06
Extended Loop	3.0E-06	4.0E-07	3.5E-06	2.1E-06	0.9E-06
SBO	4.0E-09	5.0E-10	1.1E-09	7.1E-10	6.2E-09
LOCA	1.5E-06	1.7E-07	1.6E-06	1.1E-06	4.3E-06
Flooding	2.8E-07	3.8E-08	3.8E-07	2.3E-07	9.3E-07
Loss of SWS	3.5E-08	5.0E-09	5.4E-08	2.9E-08	1.2E-07
Pipe Break	2.5E-07	3.3E-08	3.3E-07	2.0E-07	8.1E-07
Seismic < .6g	1.2E-07	1.6E-08	6.9E-08	4.4E-08	2.5E-07
Seismic => .6g	3.1E-07	3.8E-08	4.6E-08	3.1E-08	4.2E-07
LOCA w/LOOP	1.6E-06	9.6E-08	6.9E-07	4.6E-07	2.8E-06
Total	7.7E-06	9.0E-07	7.6E-06	4.7E-06	2.1E-05
% of Total	37.0%	4.3%	36.2%	22.4%	--

Table 5.E

NEAR BOILING FREQUENCY BY INITIATING EVENT
(As-Found Condition)

Initiator	Case 1	Case 2	Case 3	Case 4	Case 5	Total	f ab
Loss of SFPC	3.4E-08	4.8E-08	1.0E-07	7.6E-09	7.5E-08	2.7E-07	%4.
Loop	2.7E-06	5.1E-07	3.1E-06	9.5E-07	1.1E-06	8.3E-066	%32
Extended Loop	1.3E-05	3.7E-06	8.1E-06	3.2E-06	7.9E-06	3.6E-05	%33
SBO	4.0E-09	5.1E-10	1.1E-09	3.6E-10	5.2E-10	6.5E-09	%0.
LOCA	2.9E-06	3.6E-07	8.1E-06	8.8E-07	3.1E-06	1.5E-05	%52
Flooding	2.9E-07	6.4E-08	3.8E-07	1.2E-07	3.2E-07	1.2E-06	%7.
Loss of SWS	1.5E-07	3.3E-08	1.9E-07	5.9E-08	1.6E-07	6.0E-07	%9.
Pipe Break	2.5E-07	5.6E-08	3.3E-07	1.0E-07	2.8E-07	1.0E-06	%5.
Seismic < .6g	2.6E-07	7.6E-08	2.0E-08	2.9E-08	4.6E-08	4.3E-07	%6.
Seismic => .6g	3.1E-07	3.8E-08	4.6E-08	1.5E-08	1.5E-08	4.2E-07	%5.
LOCA w/LOOP	2.9E-06	1.8E-07	8.3E-07	1.7E-07	1.2E-07	4.2E-06	%2.
Total	2.3E-05	5.1E-06	2.1E-05	5.5E-06	1.3E-05	6.8E-05	
% of Total	33.9%	7.5%	31.1%	8.0%	19.4%	--	

Table 5.F

ESTIMATED INCREMENTAL CORE DAMAGE FREQUENCY FROM
LOSS OF SPENT FUEL POOL COOLING EVENTS
(As-fixed Condition)

ACCIDENT SEQUENCE	EST. ANNUAL NBF (from event tree quant.)	ISOLATION-RECOVERY FAILURE RANGE est. value (range from 1.0 - 0.01)	ECCS FAILURE RANGE est. value (range from 1.0 - 0.1)	EQUIPMENT OUTSIDE REACTOR BUILDING FAILURE est. value (range from 0.1 - 0.001)	INCREMENTAL ANNUAL CORE DAMAGE FREQUENCY ESTIMATION
LOOP Case 3	8.5E-7	0.1	1.0	0.01	8.5E-10
EXLOOP Case 3	3.5E-6	0.1	1.0	0.01	3.5E-9
EXLOOP Case 4	2.1E-6	0.1	1.0	0.01	2.1E-9
LOCA Case 3	1.6E-6	0.1	1.0	0.01	1.6E-9
LOCA Case 4	1.1E-6	0.1	1.0	0.01	1.1E-9
LOCA w/LOOP Case 3	6.9E-7	0.1	1.0	0.01	6.9E-10
				TOTAL ESTIMATED INCREMENTAL CDF	1.1E-8

Table 5.6

ESTIMATED INCREMENTAL CORE DAMAGE FREQUENCY FROM
LOSS OF SPENT FUEL POOL COOLING EVENTS
(As-found Condition)

ACCIDENT SEQUENCE	EST. ANNUAL NBF (from event tree quant.)	ISOLATION-RECOVERY FAILURE RANGE est. value (range from 1.0 - 0.01)	ECCS FAILURE RANGE est. value (range from 1.0 - 0.1)	EQUIPMENT OUTSIDE REACTOR BUILDING FAILURE est. value (range from 0.1 - 0.001)	INCREMENTAL ANNUAL CORE DAMAGE FREQUENCY ESTIMATION
LOOP Case 3	3.1E-6	0.1	1.0	0.01	3.1E-9
LOOP Case 4	9.5E-7	0.1	1.0	0.01	9.5E-10
LOOP Case 5	1.1E-6	0.1	1.0	0.01	1.1E-9
EXLOOP Case 3	8.1E-6	0.1	1.0	0.01	8.1E-9
EXLOOP Case 4	3.2E-6	0.1	1.0	0.01	3.2E-9
EXLOOP Case 5	7.9E-6	0.1	1.0	0.01	7.9E-9
LOCA Case 3	8.1E-6	0.1	1.0	0.01	8.1E-9
LOCA Case 4	8.8E-7	0.1	1.0	0.01	8.8E-10
LOCA Case 5	3.1E-6	0.1	1.0	0.01	3.1E-9
LOCA w/LOOP Case 3	8.3E-7	0.1	1.0	0.01	8.3E-10
SEISMIC 0.3g - 0.6g Case 1	2.6E-7	0.5	1.0	0.05	5.9E-9
				TOTAL ESTIMATED INCREMENTAL CDF	4.3E-8

Figure 5.A

Event Tree for Near Boiling Events That Go To Core Damage

Generic Core Damage Frequency (CDF) Event Tree						
	IE	I/R	ECCS	EQT		
	Near Boiling Frequency	Isolation/ Recovery -SGTS - HVAC -Fire Water -Etc.	ECCS Failure - CS - LPSIS - HPSIS - FW - CRDP -Etc.	Equipment Outside Reactor Building - Follow EOP -Etc.	Sequence	End-State
Range	From NBF	1.0 - 0.01	1.0 - 0.1	0.1 - 0.001		
Screen Value		0.10	1.00	0.01		
					1	Okay
					2	Okay
					3	Okay
					4	Core Damage

Figure 5.B

Timeline For Case 3, As-Fixed Initiators

AS-FIXED PLANT CONDITIONS: CASE 3 (LOOP, EXLOOP, LOCA, & LOCA w/ LOOP)

Unit 1 & Unit 2 SFPs are initially cross-connected.
Unit 1 SFPC System is in service using 3 SFPC pumps.
Unit 2 SFPC System is in service using 3 SFPC pumps.
Unit 1 core is in SFP, Unit 2 is operating.
Unit 1 RHR has 2 trains available for SFPC assist.
Unit 2 RHR has 1 train available for SFPC assist.

TIME:	0 hour	1 hour	4 hours	5 hours	8 hours	10 hours	20 hours	25 hours	33 hours	36 hours
EVENTS:	LOOP, EXLOOP, LOCA, or LOCA w/ LOOP		Offsite Power is not Restored. (Extended LOOP conditions).	SFPs reach 125 F (Tech Spec Limit).		Potential for late recovery of offsite power.	Potential for very late recovery of offsite power (not credited in estimation of NDF).	SFPs begin to boil. Steam may spreads at increased rate if not isolated.	Unit 2 ECCS Equipment Fails due to steam environment.	Unit 2 Core begins to uncover.
	Unit 2 SCRAM SGTS & Recirc. Isolation.									
ACTIVITIES:	Operators respond to initiator.	TSC Activated	Operators continue response for Extended LOOP and/or LOCA conditions.	TSC & Operators attempt to power appropriate non safety bus from EDGs (including 5th) for SFPC system operation.	TSC & Operators may attempt alternate means of cooling SFPs: ESW, Fire water, Feed and bleed, Pumper truck. (Not credited in estimation of NDF)			Operators attempt to stop recirculation fans.	TSC & Operators may attempt alternate means of cooling the reactor core using SLC, CRD maximize, Fire water, Pumper truck. (Not credited in estimation of CDF).	
		Operators recognize need to restore cooling to SFPs.		Operators try to restart SFPC. Operators try to align RHR for SFPC assist						

Figure 5.C

Timeline for Case 4, As-fixed Initiators

AS-FIXED PLANT CONDITIONS: CASE 4 (LOOP, EXLOOP, LOCA, & LOCA w/ LOOP)

Unit 1 & Unit 2 SFPs are initially cross connected.
Unit 1 SFPC System is in service using 3 SFPC pumps.
Unit 2 SFPC System is in service using 3 SFPC pumps.
Unit 1 core is in SFP, Unit 2 is operating.
Unit 1 RHR has 2 trains available for SFPC assist.
Unit 2 RHR has 1 train available for SFPC assist.

TIME:	0 hour	1 hour	4 hours	6 hours	8 hours	10 hours	20 hours	25 hours	33 hours	36 hours
EVENTS:	LOOP, EXLOOP, LOCA, or LOCA w/ LOOP		Offsite Power is not Restored. (Extended LOOP conditions).	SFPs reach 125 F (Tech Spec limit).		Potential for late recovery of offsite power.	Potential for very late recovery of offsite power (not credited in estimation of NBF).	SFPs begin to boil.	Unit 2 ECCS Equipment Fails due to steam environment.	Unit 2 Core begins to uncover.
	Unit 2 SCRAM SGTS & Recirc. autostart.							Steam may spreads at increased rate if not isolated.		
ACTIVITIES:	Operators respond to initiator.	TSC Activated	Operators continue response for Extended LOOP and/or LOCA conditions.	TSC & Operators attempt to power appropriate non safety bus from EDGs (including [illegible]) for SFPC system operation.	TSC & Operators may attempt alternate means of cooling SFPs. ESW, Fire water, Feed and bleed, Pumper truck. (Not credited in estimation of NBF)			Operators attempt to stop recirculation fans.	TSC & Operators may attempt alternate means of cooling the reactor core using SLC, CRD maximize, Fire water, Pumper truck. (Not credited in estimation of CDF).	
		Operators recognize need to restore cooling to SFPs.		Operators try to restart SFPC. Operators try to align RHR for SFPC assist.						

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Figure 5.D

Timeline for Case 3, As-Found Initiators

AS-FOUND PLANT CONDITIONS: CASE 3 (LOOP, EXLOOP, LOCA, & LOCA w/ LOOP)

Unit 1 & Unit 2 SFPs are initially cross connected.
Unit 1 SFPC System is out of service for maintenance.
Unit 2 SFPC system is in service using 3 SFPC pumps.
Unit 1 core is in SFP, Unit 2 is operating.
Unit 1 RHR is out of service for maintenance and is therefore not available for SFPC assist.
Unit 2 RHR has 1 train available for SFPC assist (except for LOCA event conditions).

TIME:	0 hour	1 hour	4 hours	6 hours	8 hours	10 hours	20 hours	25 hours	33 hours	36 hours
EVENTS:	LOOP, EXTENDED LOOP, LOCA, & LOCA w/ LOOP		Offsite Power is not Restored. (Extended LOOP conditions).		SFPs reach 125 F (Tech Spec limit).	Potential for late recovery of offsite power.	Potential for very late recovery of offsite power (not credited in estimation of NOF).	SFPs begin to boil. Steam spreads at increased rate.	Unit 2 ECCS Equipment Fails due to steam environment.	Unit 2 Core begins to uncover.
	Unit 2 SCRAM SGTS & Recirc. autostart.									
ACTIVITIES:	Operators respond to initiator.	TSC Activated	Operators continue response for Extended LOOP and/or LOCA.	TSC May be deactivated, if LOOP.	Operators recognize need to restore cooling to SFPs.	TSC & Operators may attempt alternate means of cooling SFPs: (SW, Fire water, Feed and bleed Pumper truck. (Not credited in estimation of NOF).		Assumed that operators do not stop recirculation fans.	TSC is reactivated if deactivated in LOOP after power restoration.	
				Operators may perform a rapid restart of Unit 2, if LOOP.	TSC & Operators attempt to power appropriate non-safety bus from EDGs (including 6th) for SFPC system operation.				TSC & Operators may attempt alternate means of cooling reactor core including: SLC, RWCU, Fire Water, CRD maximized, RHR SW, Pumper truck. (Not credited in estimation of CDF).	
					Operators try to restart SFPC.				If restarted, Unit 2 SCRAMS or is shutdown due to ECCS failures.	
					Operators try to align RHR for SFPC assist.					

Figure 5.E

Timeline for Case 4, As-Found Initiators

AS-FOUND PLANT CONDITIONS: CASE 4 (LOOP, EXLOOP, & LOCA)

Unit 1 & Unit 2 SFPs are initially isolated (not cross-connected).
Unit 1 SFPC System is service using 3 SFPC pumps.
Unit 2 SFPC system is in service using 3 SFPC pumps.
Unit 1 core is in SFP, Unit 2 is operating.
Unit 1 RHR has 1 train available for SFPC assist.
Unit 2 RHR has 1 train available for SFPC assist (except for LOCA event conditions).

TIME:	0 hour	1 hour	4 hours	6 hours	8 hours	10 hours	20 hours	25 hours	33 hours	36 hours
EVENTS:	LOOP, EXTENDED LOOP, & LOCA		Offsite Power is not Restored. (Extended LOOP conditions).		SFPs reach 125 F (Tech Spec Limit).	Potential for late recovery of offsite power.	Potential for very late recovery of offsite power (not credited in estimation of NBF).	SFPs begin to boil.	Unit 2 ECCS Equipment fails due to steam environment.	Unit 2 Core begins to uncover.
	Unit 2 SCRAM							Steam spreads at increased rate.		
	SGTS & Recirc. autostart.									
ACTIVITIES:	Operators respond to Initiator.	TSC Activated	Operators continue response for Extended LOOP or LOCA.	TSC May be deactivated, if LOOP.	Operators recognize need to restore cooling to SFPs.	TSC & Operators may attempt alternate means of cooling SFPs: ESW, Fire water, Feed and bleed, Pumper truck. (Not credited in estimation of NBF).		Assumed that operators do not stop recirculation fans.	TSC is reactivated if deactivated in LOOP after power restoration.	
				Operators may perform a rapid restart of Unit 2, if LOOP.	TSC & Operators attempt to power appropriate non-safety bus from EDGs (including bus for SFPC system operation).				TSC & Operators may attempt alternate means of cooling reactor core including: SLC, RWCU, Fee Water, CRD maximized, RHR SW, Pumper truck.. (Not credited in estimation of CDF).	
					Operators try to restart SFPC.				If restarted, Unit 2 SCRAMS or is shutdown due to ECCS failures.	
					Operators try to align RHR for SFPC assist.					

Figure 5.F

Timeline for Case 5, As-Found Initiators

AS-FOUND PLANT CONDITIONS: CASE 5 (LOOP, EXLOOP, & LOCA)

Unit 1 & Unit 2 SFPs are initially isolated (not cross connected).
Unit 1 SFPC System is service using 3 SFPC pumps.
Unit 2 SFPC system is in service using 3 SFPC pumps.
Unit 1 core is in SFP, Unit 2 is operating.
Unit 1 RHR has 2 trains available for SFPC assist.
Unit 2 RHR has 1 train available for SFPC assist (except for LOCA event conditions).

TIME:	0 hour	1 hour	4 hours	5 hours	6 hours	8 hours	10 hours	15 hours	20 hours	23 hours	26 hours
EVENTS:	LOOP, EXTENDED LOOP, & LOCA		Offsite Power is not Restored. (Extended LOOP conditions).	SFPs reach 125 F (Tech Spec Limit).			Potential for late recovery of offsite power.	SFPs begin to boil	Potential for very late recovery of offsite power (not credited in estimation of NBF).	Unit 2 ECCS Equipment Fails due to steam environment.	Unit 2 Core begins to uncover.
	Unit 2 SCRAM SGTS & Recirc. autostart.							Steam spreads at increased rate.			
ACTIVITIES:	Operators respond to Initiator.	TSC Activated	Operators continue response for Extended LOOP or LOCA.	Operators recognize need to restore cooling to SFPs.	TSC May be deactivated, if LOOP.	TSC & Operators may attempt alternate means of cooling SFPs: ESW, Fire water, Feed and bleed, Pumper truck. (Not credited in estimation of NBF).		Assumed that operators do not stop recirculation fans.		TSC is reactivated if deactivated in LOOP after power restoration.	
				TSC & Operators attempt to power appropriate non-safety bus from EDGs (including 6kV for SFPC system operation.	Operators may perform a rapid restart of Unit 2, if LOOP.					TSC & Operators may attempt alternate means of cooling reactor core including: SLC, RWCU, Fire Water, CRD maximized, RHR SW, Pumper truck... (Not credited in estimation of CDF).	
				Operators try to restart SFPC.						If restarted, Unit 2 SCRAMS or is shutdown due to ECCS failures	
				Operators try to align RHR for SFPC assist.							

6.0 RADIOLOGICAL ASSESSMENT

In the November 27, 1992, Part 21 Report concerning the potential substantial safety hazard resulting from a loss of spent fuel pool (SFP) cooling, the authors expressed concern that the dose associated with a postulated LOCA would preclude any operator actions within the reactor building to restore cooling or provide make-up water to the SFP. The authors of the Part 21 Report noted that the analysis performed by the licensee to evaluate operator dose for actions inside secondary containment against the design basis criteria established in NUREG-0737 (Ref.27), Item II.B.2, did not include doses from airborne radioactivity. Although consideration of airborne radioactivity may be inferred from the containment leakage assumptions in Reference 2, Item II.B.2 does not reference these assumptions. As discussed in Appendix A to this SE, the consideration of an airborne source term outside primary containment is not required for demonstrating the adequacy of plant shielding for a LOCA environment as specified in Item II.B.2 of Reference 27.

6.1 RISK ASSESSMENT CONSIDERATIONS

The NRC policy for addressing safety issues raised that are outside the design basis of a nuclear power plant is to determine whether, in light of the issue raised, the plant poses an undue risk to the public health and safety that would warrant NRC action in concert with its backfit policy. The staff's evaluation of the risk posed by the accident scenario presented in Reference 1 is given in Section 5.0 of this SE. This evaluation determined that the probability of a LOCA that results in significant reactor core damage and the consequential release of radioactive materials, early enough in the accident to interfere with plant access, is such that it constitutes a negligible contribution to risk. The total activity in normal reactor coolant from a LOCA (without core damage) is not sufficient to present an impediment to operator access. The total dose-equivalent Iodine-131 in reactor coolant during normal operations, based on the maximum concentration allowed by Technical Specifications, is two to three orders of magnitude less than the Iodine-131 gap activity released per the Draft NUREG-1465 (Ref. 28) assumptions. As discussed in section 6.2 below, the staff has determined that, using the Reference 28 assumptions, operator access would not be impeded if the reactor fuel gap activity was released by the LOCA. Therefore, there are no radiological considerations postulated for the in-plant operator actions included in the staff's risk analysis.

6.2 LICENSEE'S ASSESSMENT

Not withstanding PP&L's position that considering the loss of spent fuel pool cooling concurrent with a loss of coolant accident (LOCA) is not within its licensing basis, the licensee contended that they realistically would have sufficient access to the reactor building during a LOCA to recover from a loss of pool cooling even if an airborne source term, as postulated in Reference 1, is assumed. In Reference 11, as revised by letters dated January 4, 1994 (Ref. 29), and February 2, 1994 (Ref. 30), the licensee submitted an assessment of the radiation exposure associated with a spectrum of operator actions they would rely on to either restore cooling, or provide make up to the SFPs following a LOCA. Dose estimates are tabulated in References 29 and

30 for three different postulated accidents resulting in the release of 1% of the reactor fuel gap activity, 100% of the gap activity, and the release fractions assumed in TID-14844 (Ref. 31).

The staff determined that the level of detail in References 29 and 30 was insufficient for the staff to verify the licensee's results. At the staff's request, a public meeting with the licensee was held on March 15, 1994, to review the licensee's detailed calculations. The staff's review identified a number of source term assumptions that were not technically supported. Subsequently, the staff independently calculated three postulated source terms and adjusted the doses tabulated in References 29 and 30. These source terms include Reference 28 assumptions for 1) gap activity release and 2) early-in-vessel core damage accident cases, as well as 3) the Reference 31 release fraction assumptions. The staff's evaluation indicated that operator access is reasonably assured for accidents resulting in the postulated release of the gap activity only. The staff's evaluation did not support the assertion that there would be sufficient reactor building access if airborne radioactivity produced from the release of a significant fraction of the of the reactor core activity is postulated. However, as discussed in sections 6.1 and 6.3.1 of this report, the scenarios and assumptions made in the licensee's analysis are neither those required by the design basis analysis, nor do they conform to the risk assessment assumptions. Therefore, the staff did not use the results of this analysis in addressing the safety issues raised by Reference 1.

6.3 DESIGN BASES QUESTIONS

During the course of its review of the issues raised by Reference 1, the staff determined that the Susquehanna licensing basis does include a commitment to be able to add ESW make-up water to the spent fuel pool during a LOCA. Also, through the course of this review, the licensee has modified the configuration of the plant to address several technical issues. In particular, Susquehanna has committed to cross-connect the unit 1 and 2 SFPs by removing the gates between each pool and the common fuel transfer cask pit. In Reference 32, the staff requested that PP&L provide additional information to demonstrate that the original Susquehanna plant configuration met its licensing basis.

6.3.1 COMPLIANCE WITH ORIGINAL PLANT CONFIGURATION

In Reference 6 and by letter dated July 11, 1994 (Ref. 33), PP&L submitted an analysis, consistent with the design basis requirements in Item II.B.2 of Reference 27, for operators accessing the affected unit's reactor building during a LOCA to add ESW make up water to the SFP (without cross-connected pools). This analysis divided the action into two missions: 1) operator access to the 670 foot elevation to tie-in ESW make-up to the SFP, and 2) operator access to the 749 foot elevation to control the ESW make-up flow. Assumed operator actions for each mission, such as transient times, stair climbing rates, and residence times in various plant areas, were based on a videotaped-demonstration in full protective clothing and respirator. The radiation sources of concern (i.e., systems that could contain reactor coolant containing the source term described in Reference 31) were identified as Core Spray System piping, ranging in size from 3 inches to 14 inches in diameter, that run through or are in the proximity to the spaces requiring access. The quantities of radionuclides in the suppression pool water contained in this Core Spray piping were calculated based on the Reference 31 assumptions specified in Item II.B.2 of Reference 27. In Reference 33, PP&L calculated that it would take greater than 40 hours following the loss of pool cooling for the pool level to decrease to the minimum level allowed by Technical Specifications (22 feet above the top of the fuel). Therefore, the analysis assumed that the missions would be performed 40 hours after the LOCA-initiated loss of SFP cooling. The suppression pool source term was decayed for 40 hours and radiation dose rates were calculated using Microshield, a commercially available, copyrighted, point-kernel shielding calculational computer code.

The model used to calculate the mission doses broke the access/egress routes for each mission into several iterative segments. The distance from the center point of each segment to each source of concern was measured and the distance-dependent dose rate contribution from each source was determined. The integrated dose for each mission was approximated by summing the product of the transient or residence time in each iterative segment times the total dose rate at the center of that segment as described by equation (1).

$$D_m=\sum_{i=1}^{x}\sum_{j=1}^{y} t_i * d_{ij} \tag{1}$$

where: D_m is the integrated dose for the m*th* mission

t_i is the transient/residence time for the i*th* segment of the mission.

d_{ij} is the dose rate at the center of the i*th* segment from the j*th* source.

x is the number of segments in the m*th* mission.

y is the number of sealed sources considered in the m*th* mission.

The staff's evaluation of PP&L's analysis included a review of the detailed calculations submitted. The staff determined that the licensee used appropriate calculational models and methods that are of sufficient detail to achieve reasonably precise dose estimates for operators performing the identified tasks. In addition, the staff has performed independent calculations with TACT 5 and Microshield, using the design basis assumptions in Reference 27, to verify the licensee's results. The staff concludes that there is reasonable assurance that the Susquehanna operators can complete the actions necessary to add ESW make-up water to the spent fuel pool during a

LOCA without exceeding 5 rem to the whole body or its equivalent to any part of the body. Therefore, the staff also concludes that Susquehanna, as originally configured, met its licensing basis.

6.3.2 CROSS-CONNECTED POOLS

As discussed elsewhere in this report, PP&L has committed to remove the gates separating the fuel transfer cask pit from each SFP such that SFP cooling or make-up water can be provided by operator actions in the non-accident unit. There are no design basis radiological considerations for access to the unaffected unit's reactor building during a LOCA.

7.0 Conclusions

7.1 Safety Significance

Based on a deterministic analysis of the plant as it is currently configured, considering recent plant modifications and procedural improvements, the staff concludes that systems used to cool the spent fuel storage pool are adequate to prevent unacceptable challenges to safety related systems needed to protect the health and safety of the public during design basis accidents.

The probabilistic review determined that the specific scenario originally described by the report authors is a very low probability sequence. The overall low probability of the scenario described in Reference 1 was driven by the low probability of LOCA sequences that incurred severe early core damage that would pose a threat to operator access to the reactor building. However, the staff did not limit the probabilistic analysis to the specific Reference 1 scenarios. The staff recognized that numerous other initiating events had the potential to cause a loss of spent fuel pool cooling. The staff examined the risk that these initiating events, including seismic events, loss of off-site power events, and flooding events could lead to spent fuel pool boiling sequences that jeopardized safety related equipment needed to maintain reactor core cooling. The staff also recognized that the failure mechanisms by which the operators would be unable to provide cooling to the spent fuel pool were not limited to operator access consideration. Thus, the staff also modeled LOCA/ boiling pool sequences that did not consider operator access restrictions. The staff concluded that, even with consideration of the additional initiating events, loss of spent fuel pool cooling events represented a low safety significance challenge to the plant at the time the issue was brought to the staff's attention.

During the course of the staff review, the licensee completed several modifications to the facility, including removal of the gates that separate the spent fuel storage pools from the common cask storage pit, installation of remote spent fuel pool temperature and level indication in the control room and numerous procedural upgrades. The staff evaluated the safety significance of the engineers concerns with respect to the configuration of the Susquehanna facility as it existed at the time of the Part 21 report and as it exists at the present time. The staff concluded that the plant modifications and procedural upgrades provided a measurable improvement in plant safety. On the basis of this conclusion, the staff has initiated an effort to examine certain issues related to spent fuel pool cooling reliability in greater detail on a generic basis.

7.2 Compliance Issues

The staff concluded when it issued the licensing SER as NUREG-0776 (Ref. 34) that the design of systems to cool the spent fuel pools were adequate and acceptable. Specific discussion was provided regarding the seismic classification of the design and specific discussion was provided concerning the role of the Emergency Service Water system in providing makeup water to the spent fuel pools. The staff concluded previously (Ref. 3) that the scenario described in Reference 1 was beyond that for which the staff had found the spent fuel pool cooling system design acceptable during the licensing process. Additional aspects of the overall facility design that might be impacted by the potential failure of the spent fuel pool cooling system do not change the conclusion that the basic scenario outlined in Reference 1 is beyond the licensing basis of the facility.

The staff found the licensee's commitment described in Reference 5 to remove the cask storage pit gates, as described elsewhere in this evaluation, adequate to resolve licensing basis concerns regarding SGTS performance following design basis seismic events. The licensee's proposal that the RHR Fuel Pool Cooling Assist mode represent the design and licensing basis means for cooling the spent fuel pool following a seismic event remains open pending review and confirmation to the staff by the licensee that design and operation of the RHR fuel pool cooling assist mode, including such issues as inclusion of various valves in the licensee's inservice test program, is consistent with this purpose.

The staff also found that the licensee's commitment described in Reference 5 to remove the cask storage pit gates as described elsewhere in this evaluation adequate to resolve licensing basis concerns regarding the ability to add makeup to the spent fuel pools under design basis conditions.

Compliance issues regarding 1) adequacy of safety evaluations performed pursuant to 10 CFR 50.59 for several procedural and plant modifications and 2) adequacy of operability and reportability determinations pursuant to 10 CFR Part 50.72/50.73 for a number of related issues remain open. Closure for these items will be addressed in separately in Reference 9.

7.3. RADIOLOGICAL CONSIDERATIONS

The staff concluded that the licensee meets the design and licensing basis with regard to the provision of spent fuel pool makeup under accident conditions from the ESW system. The staff notes that the licensing and design basis of the SSES facility does not include consideration of post-accident airborne activity.

The staff's radiological evaluation of actions to recover from a loss of spent fuel pool cooling indicated that operator access is reasonably assured for accidents resulting in the postulated release of the gap activity only. The staff's evaluation did not support the assertion that there would be sufficient reactor building access if airborne radioactivity produced from the release of a significant fraction of the of the reactor core activity is postulated. These conclusions take into account airborne radioactivity and as such, are beyond the design and licensing basis of the facility. The staff determined that the probability of early core damage that would restrict access for actions to recover from a loss of spent fuel pool cooling is small (see Section 5.1) and that the additional potential consequences of a sustained loss of spent fuel pool cooling and make-up are not significant relative to the potential consequences of reactor vessel core damage (see Section 5.2).

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2. U.S. Nuclear Regulatory Commission, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors," Regulatory Guide 1.3.

3. J. W. Shea, NRC, letter to D. A. Lochbaum and D. C. Prevatte, March 16, 1994, "Susquehanna Steam Electric Station, Units 1 and 2, Spent Fuel Pool Cooling Issue (TAC No. M85337)."

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14. R. G. Byram, PP&L, letter to C. L. Miller, NRC, November 3, 1993, "Susquehanna Steam Electric Station Response to 10/20/93 RAI on Spent Fuel Pool Cooling System."

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18. R. G. Byram, PP&L, letter to C. L. Miller, NRC, March 25, 1994, "Susquehanna Steam Electric Station Response to Request For Additional Information Concerning Standby Gas Treatment System."

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APPENDIX A

LICENSING BASIS REVIEW

A.1 Introduction

In a letter dated March 16, 1994, the staff presented the results of a review of the licensing basis of the SSES facility as it pertained to the issues in the Part 21 report. The information in the March 16, 1994 letter was presented to the authors at a public meeting on March 14, 1994. The staff drew several conclusions in the March 16, 1994 letter. The staff concluded that the link between loss of SFP cooling events and design basis loss of coolant accidents (LOCA) and/or loss of off-site power (LOOP) events postulated by the authors of the Part 21 report could not be considered within the original licensing basis of the Susquehanna facility. As a result, the staff stated that the issues in the Part 21 report did not represent compliance issues as that term is used in 10 CFR Part 50.109(a)(4)(i), "Backfitting". Rather, the staff concluded that an evaluation of the potential safety significance of the LOCA/boiling SFP issues must be conducted to determine whether any changes to the facility were necessary for the continued assurance of no undue risk to the public health and safety or whether any safety enhancements, providing significant safety benefit at a justifiable cost, were warranted.

The Part 21 report authors objected to the staff's conclusions regarding the licensing basis of the Part 21 report issues. Their objections were voiced at the March 14, 1994 public meeting and were further documented in a letter dated March 21, 1994. In the March 21, 1994 letter and an additional letter dated May 10, 1994, the authors provided additional information they believed relevant to the staff's conclusions regarding the licensing basis. The information consisted of twelve numbered arguments and several unnumbered discussions on various regulations, licensing documents and licensing history. The author's requested that the staff consider this additional information before issuing a final safety evaluation on the Part 21 report issues.

As a result of the additional review conducted by the staff following receipt of the March 21 letter, the staff drew an additional conclusion regarding the licensing basis of systems related to the spent fuel pool. Although the staff remains convinced that boiling of a spent fuel pool in conjunction with a LOCA or LOOP was not part of the basis on which the facility was licensed, the staff concluded that makeup to the spent fuel pool(s) during accident events was considered by the applicant (now licensee) and the staff and forms part of the design and licensing basis of the facility. Specifically, the staff concluded that provision of makeup to the spent fuel pool from the emergency service water system during a design basis accident, including design basis loss-of-coolant accident, is within the design and licensing basis of the SSES facility. The staff review did not conclude that boiling of the spent fuel pool was necessarily implied but recognizes that makeup to the pool will be necessary to compensate for, at the very least, evaporative losses. In a letter to the licensee dated April 21, 1994, the staff requested information from the licensee regarding the ability to provide makeup water to the spent fuel pool from the ESW system under design basis accident conditions. By

letter dated May 5, 1994 the licensee provided a response. The ability of the licensee to add makeup water to the spent fuel pool under accident conditions is evaluated in Section 6.3 of the staff's safety evaluation.

In addition to the conclusions regarding the scenarios described in the Part 21 report, the staff determined that boiling of the spent fuel pool following a seismic event was within the licensing basis of the facility. Further, the staff concluded that successful operation of the standby gas treatment system (SGTS) during a seismic/boiling pool event was assumed in the licensing basis. In a letter dated March 7, 1994, the staff requested information from the licensee on the ability of the facility to meet the licensing basis for the seismic/boiling pool event.

The licensee responded by letters dated March 25, 1994, April 29, 1994, and May 4, 1994. The licensee determined that SGTS performance would begin to degrade after prolonged operation to ventilate the vapor from a boiling spent fuel pool outside the rear building. The licensee's calculations showed that SGTS would eventually degrade as a result of condensate accumulation in the SGTS duct and recirculation plenum. The calculation indicated that an unanalyzed condition may be reached several days following the onset of boiling in a single pool, and less than one day after the onset of boiling in both pools.

In a letter dated May 19, 1994, the staff indicated that degradation of SGTS performance during a seismically induced pool boiling event represented a discrepancy with respect to the plant's licensing basis. The staff requested that the licensee state how this issue was planned to be addressed. The licensee responded by letter dated June 1, 1994, with a commitment to operate the spent fuel pools with the cask storage pit gates removed except during infrequent periods involving cask pit operations. During a telephone conference on July 1, 1994, the licensee confirmed their intent to resolve the licensing basis concerns by reviewing the design basis of the RHR system and the facility, and upgrading it as necessary, such that SFP cooling following a seismic event is included as a safety function of the RHR system. The staff concluded that the commitment to operate with the pools normally cross-connected and the completion of design basis changes to include SFP cooling as a safety function of the RHR system are adequate measures to exclude pool boiling from consideration as a direct consequence of a seismic event. The SGTS would no longer be relied upon to ventilate vapor a boiling SFP, and the staff could consider the seismic event licensing basis concerns to be resolved. Further technical discussion on this issue is documented in Section 5.4.2.2 of the staff's safety evaluation.

This SE addresses compliance of the facility design to the licensing basis as discussed in the previous paragraphs. Several additional issues with potential compliance issues were raised in the Part 21 report and subsequent correspondence. These issues include 1) adequacy of safety evaluations performed pursuant to 10 CFR 50.59 for several procedural and plant modifications, 2) adequacy of operability and reportability determinations pursuant to 10 CFR Part 50.72/50.73 for a number of related issues. The NRC will address these compliance issues in separate correspondence.

Because of the staff conclusions regarding the licensing basis as it pertained to potential LOCA/boiling pool events of LOCA/LOOP/boiling spent fuel pool events, the staff's safety review of the scenarios presented in the Part 21 report was oriented toward confirming, if appropriate, the continued assurance of adequate protection or toward determination of whether safety enhancements could be developed and justified. The role of this type of review in the NRC's mission was described in detail in the March 16, 1994 staff letter to the authors of the Part 21 report.

The staff did review all of the points in the March 21 and May 10, 1994 correspondence. The staff's response to those points is described below. In conducting its review of the licensing basis, the staff did note certain inconsistencies in staff review practice at the time of plant licensing and these inconsistencies are also described below.

A.2 Licensing Basis Principles

In reviewing the information provided in the March 21 and May 10, 1994 letters, the staff applied the same principles regarding the licensing basis as were applied to the review described by the staff in the March 14, 1994 public meeting. The staff recognizes that no definition of the current licensing basis exists in the regulations under 10 CFR Part 50 for operating reactors. The staff noted in SECY-92-314 that there is no industry wide agreement on the term current licensing basis and stated it would work to define CLB for operating reactors. The Commission's Office of Policy Planning noted in OPP-92-02 that definition of the CLB would benefit the staff in applying 10 CFR Part 50.54(f) and in deciding on whether a backfit analysis is required. However, to date, the Commission has not adopted a definition of the CLB for operating reactors. Although a definition of CLB is not provided in 10 CFR Part 50, the staff adopted a definition of CLB in Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability." That definition states:

> Current licensing basis (CLB) is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for assuring compliance with and operation within applicable NRC requirements and the plant specific design basis (including all modifications and additions to commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 30, 40, 50, 51, 55, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions, and Technical Specifications (TS). It also includes the plant-specific design basis information in 10 CFR 50.2 as documented in the most recent Final Safety Analysis Report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

The above definition is similar to that provided in 10 CFR Part 54 for license renewal and in Section 1.3.2 of NUREG-1412, "Foundation for the Adequacy of the Licensing Basis," which was referenced by the authors in their March 21, 1994 correspondence. NUREG-1412 notes that the CLB means the "Commission requirements imposed on the plant that are in effect..." (emphasis added). With regard to the design compliance issues raised in the Part 21 report, the staff reviewed the general design requirements, Standard Review Plan guidance, Regulatory Guides and correspondence related to spent fuel pool storage and cooling systems and other related systems that were in existence and applicable at the time of the Susquehanna licensing review. The staff further reviewed how the existing requirements and guidance were applied during the plant specific review of the proposed SSES design.

A.3 Regulatory Design Standards and Review Criteria

A.3.1 General Design Criteria

In the 1960's, the scope and detail of review of proposed nuclear plant designs was less standardized than it is today. In July, 1967, the Atomic Energy Commission (AEC) published for comment proposed general design criteria (GDC) for nuclear power plants that established minimum requirements for principal design standards. The rule was issued in final in February 1971. The GDC are located in Appendix A to 10 CFR Part 50. The GDC are invoked through 10 CFR Part 50.34 (a)(3) which states that:

> (a) Preliminary Safety Analysis Report.
>
> Each application for a construction permit shall include a preliminary safety analysis report. The minimum information to be included shall consist of the following:
>
> > (3) The preliminary design of the facility including:
> >
> > (i) The preliminary design criteria for the facility. Appendix A, General Design Criteria for Nuclear Power Plants establishes minimum requirements for the principal design criteria for water cooled nuclear power plants similar in design and location to plants for which construction permits have been previously issued by the Commission and...

The GDC are requirements only to the extent that the applicant is required to describe conformance with them in the PSAR. The staff's plant specific design review verifies that the overall plant design satisfies the GDC requirements and that the plant can be safely operated.

The staff's letter of March 16, 1994 described in part the GDC that applied to spent fuel pool cooling function. The applicable GDC are reviewed again below:

> <u>GDC 2, "Design Bases for Protection Against Natural Phenomenon"</u>
>
> Structures, systems and components important to safety shall be

designed to withstand the effects of natural phenomena such as earthquakes, ... without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin..., (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety function to be performed.

GDC 4. "Environmental and Dynamic Effects Design Bases"

Structures, systems and components important to safety shall be designed to accommodate the effects of and be compatible with the environmental conditions associated with the normal operation, maintenance, testing and postulated accidents, including loss-of coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluid, that may result from equipment failures and from events outside the nuclear power unit. However, ...

GDC 5. "Sharing of Systems, Structures and Components"

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety function, including, in the event of an accident in one unit, an orderly and cooldown of the remaining units.

GDC 44. "Cooling Water"

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. the system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for on-site electric power system operation (assuming off-site power is not available) and for off-site electric power system operation (assuming on-site power is not available) the system safety function can be accomplished using a single failure.

GDC 45. "Inspection of Cooling Water System"

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

GDC 46."Testing of Cooling Water System"

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing ...

GDC 61. "Fuel Storage and Handling and Radioactivity Control"

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and to her residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

GDC 63. "Monitoring Fuel and Waste Storage"

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

A.3.2 Regulatory Guides

In the early 1970's, the AEC developed safety guides (later regulatory guides) to provide guidance on acceptable methods for implementing the various GDC. The regulatory guides were designed to standardize and promulgate existing staff review practices. Regulatory guides do not constitute regulatory requirements, but are one method, acceptable to the staff, for demonstrating compliance with various GDC. With adequate technical bases, applicants may propose and, if approved, use alternate assumptions. Several of these regulatory guides (RG) discuss spent fuel storage and cooling systems or other systems and issues raised in the Part 21 report. The applicable regulatory guides are described below.

RG 1.13, "Spent Fuel Storage Facility Design Basis," (Revision 1, 12/75) was used as guidance in the licensing evaluation of many spent fuel storage facilities. RG 1.13 described an acceptable method of implementing GDC 61 in order to:

(1) Prevent loss of water from the fuel pool that would uncover fuel,

(2) Protect fuel from mechanical damage, and

(3) Provide the capability for limiting the potential off-site exposures in the event of a significant release of radioactivity from the fuel.

RG 1.13 does not provide specific guidance for evaluation of SFP cooling systems. However, Section C.6 of RG 1.13 states that systems for maintaining water quality and quantity should be designed so that any maloperation or failure of such systems (including failures resulting from the Safe Shutdown Earthquake) will not cause fuel to be uncovered. It further states that such systems need not otherwise meet Category I seismic requirements. Thus, RG 1.13 suggests that SFP cooling systems need not be designed to seismic Category I requirements. However, in its introduction, RG 1.13 states that fuel handling and storage systems be designed with appropriate containment, confinement and filtering systems, and be designed to prevent significant reduction in the coolant inventory of the storage facility under accident conditions.

RG 1.13 does not offer any additional insight as to what type of accidents need be considered in the design (i.e., accidents involving the SFP and its systems, or accidents triggered by other facility events (LOCA, LOOP)) of the SFP cooling systems. RG 1.13 neither specifically includes nor excludes consideration of LOCA-induced loss of SFP cooling events as within the design basis. However, RG 1.13 does not specifically limit the accidents to be considered in the design basis to seismic events.

RG 1.29, "Seismic Design Classification" provides guidance on methods acceptable to the NRC for identifying and classifying features of nuclear plants that should be designed to withstand the effects of an SSE. RG 1.29 is used in evaluating facilities with respect to the requirements of GDC 2 and Appendix A to 10 CFR Part 100. Section C of RG 1.29 designates certain systems as Seismic Category I and states that such systems should be designed to withstand the effects of an SSE and remain functional. Section C.1.d cites "systems or portions of systems that are required for cooling the spent fuel storage pool" as Seismic Category I systems.

RG 1.52, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," presents methods acceptable to the NRC for implementing the GDC with regard to the design of post-accident ESF atmosphere cleanup system. Section C.1 of RG 1.52 states that ESF atmosphere cleanup systems should be based on the maximum pressure differential, radiation dose rate, relative humidity, maximum and minimum temperature and other conditions resulting from the postulated DBA and on the duration of such conditions. The RG further states that the design of each adsorber section should be based on activity concentrations and species described in RG 1.3.

RG 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors" provides guidance on acceptable assumptions for evaluating the off-site radiological consequences of a LOCA at a BWR. As with all regulatory guides, the criteria in RG 1.3 do not constitute regulatory requirements, but are one method, acceptable to the staff, for demonstrating the regulatory requirement (citing criteria) in 10 CFR Part 100. The assumptions given in RG 1.3 include the fraction of the radioactivity in the reactor core that is released into the reactor containment, the transport of radioactivity through the

reactor plant (containment leakage, hold up, filtration, radiological decay,etc.), atmospheric diffusion models acceptable for determining the dilution and transport of the release plum off-site, and acceptable dose conversion factors for determining radiation dose to the public. The fraction of radioactivity released from the reactor (source term) in RG 1.3 is based on the guidance in Technical Information Document (TID) 14844.

The RG 1.3 assumptions are also acceptable to the NRC for demonstrating that the reactor control room design provides a habitable environment for the control room operators during the course of an accident without exceeding the radiation dose criteria in 10 CFR 50 Appendix A, General Design Criteria (GDC) 19.

A.3.3 Standard Review Plan

Section 1.1 of the Final Safety Evaluation Report (NUREG-0776, "Safety Evaluation Report Related to the Operation of Susquehanna Steam Electric Station, Units 1 and 2."; FSER) states: "The design of the station was reviewed against Federal regulations, construction permit criteria and our Standard Review Plan, NUREG-75/087, September 1975. Specific Standard Review Plan sections are frequently referenced throughout the text as the basis for our acceptance." Section 9.1.3 of NUREG-75/087 describes the specific acceptance criteria for the integrated design of the spent fuel pool cooling and cleanup system. The listed acceptance criteria include aspects of GDC 2, 4, 5, 45 and 46 and 63. GDC 44 is listed as an acceptance criteria as it pertains to:

(1) The capability to transfer heat loads from safety-related structures,systems, and components to a heat sink under both normal operating and accident conditions.

(2) Suitable redundancy of components so that safety functions can be performed assuming a single active failure of a component coincident with the loss of all off-site power.

(3) The capability to isolate components, systems, or piping, if required, so that the system safety function will not be compromised.

Elements of GDC 61 are listed as an acceptance criteria; however, only elements (1), (2) and (3) of GDC 61 are listed. Finally, aspects of Regulatory Guides 1.13, 1.26 and 1.29 and Branch Technical Position APSCB 3-1 are listed as acceptance criteria.

The SRP provides of a detailed description of the review procedures that are to be used in reviewing the proposed system design against the above acceptance criteria. The procedures specifies the review of failure modes and effects and seismic design and specifies an evaluation of the systems capability to perform its safety function under normal, abnormal and accident conditions.

A revised version of the SRP was issued in 1981 as NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power

Plants," (SRP)". Section 9.1.3 of NUREG-0800 is revised from Section 9.1.3 of NUREG-75/087. The primary change is that NUREG-0800 allows two bases for reviewing the ability of spent fuel pool cooling systems to provide adequate cooling under all operating conditions. Cooling portions of the systems may be designed to (1) seismic Category I, Quality Group C requirements or (2) non-seismic Category I, Quality Group C requirements provided that certain systems are designed to seismic Category I requirements including fuel pool makeup system and source and the fuel pool building and its ventilation system. The specific acceptance criteria for GDC 2 requirements are modified to reflect the option of installing a non-seismic Category I fuel pool cooling system. The acceptance criteria for GDC 2 specifically references the guidelines of Regulatory Guide 1.52 for ventilation and filtration systems for non-seismic Category I cooling system facilities.

A.4 Licensing History

A.4.1 Interactions Regarding Fuel Pool Cooling System Design

The NRC criteria for acceptance of SFP cooling systems has evolved from case-by-case reviews for early plants to the present guidance of the SRP, NUREG-0800, regulatory guides, and the requirements of the GDC of 10 CFR Part 50, Appendix A. During the evolution of the NRC design standards, industry representatives provided feedback regarding fuel pool cooling design requirements.

By letter dated January 3, 1975, Bechtel Power Corporation initiated a series of correspondence and meetings between Bechtel and the staff concerning the safety-grade and seismic Category I design requirements for spent fuel pool cooling system. The dialogue was initiated by Bechtel on behalf of a number of sites for which Bechtel had design responsibility for this system. Bechtel proposed that design of spent fuel pool cooling systems to safety grade and seismic Category I standards would not result in any significant benefits to the public health and safety. In addition, Bechtel provided an analysis of the dose consequences of spent fuel pool cooling system failure and heat removal by pool boiling. The study also evaluated the effects of steam on the fuel building ventilation systems. Bechtel requested that the staff consider their analyses.

The staff responded by letter dated January 28, 1975 in which the staff indicated the Bechtel analyses were under review. The staff issued a request for additional information on May 12, 1975, to which Bechtel responded on June 11, 1975. A series of meetings between Bechtel and the staff were held to further discuss the issue. By letter dated October 2, 1975, the staff concluded that, "...in the absence of data indicating that there will be no significant I-131 release to the pool as a result of pool heat-up, or an analysis that demonstrates that the pool water will not reach boiling following postulated failure of the pool cooling system, the spent fuel pool cooling system should continue to be classified and designed as a safety grade system in accordance with Regulatory Guides 1..26 and 1.29."

The interactions between Bechtel and the staff were not of themselves part of any specific licensing proceedings. Individual applicants were responsible for obtaining NRC approval for the proposed facility design, including the design of spent fuel pool cooling systems. By letter dated October 9, 1975, PP&L informed the staff that, based on the above interactions between Bechtel and the staff, PP&L was revising the design of the fuel pool cooling system to Quality Group D and seismic Category II standards. In a letter dated December 10, 1975, the applicant revised the October 9, 1975 commitment by stating that the fuel pool cooling system would classified as Quality Group C with the exception of the cleanup portion of the system. PP&L stated that the Preliminary Safety Analysis Report (PSAR) would be revised to reflect this change.

In Revision 19 of the PSAR, the applicant revised the proposed design of the spent fuel pool cooling system accordingly. No further documented interactions between the applicant and the staff on the fuel pool cooling system design appear until the NRC staff issued a request for additional information to the applicant dated November 22, 1978. In question 010.11 of that RAI, the staff stated:

> The spent fuel pool cooling system is a non-seismic system. This does not meet the guidelines set forth in Regulatory Guide 1.13 and 1.29. Analyze the design of the spent fuel pool cooling system to show that the pumps and piping are supported so that they are capable of withstanding an SSE, or provide the results of an analysis to show that for the complete loss of fuel pool cooling that would result in pool boiling, a release of significant quantities of radioactivity to the environment will not result.

By letter dated March 12, 1979, the applicant filed Amendment 7 containing Revision 5 to the SSES FSAR. The applicants response to question 010.11 is contained in FSAR Revision 5. The response states:

> A complete analysis showing the amount of radioactive release following a complete loss of fuel pool cooling is provided in Appendix 9-A. As shown in Table 9A-1 the thyroid dose consequences of the boiling pool are well below the guideline values of 10 CFR 100 and the 1.5 REM thyroid guideline.
>
> Subsection 9.1.2.3.2 provides the logic which shows that the spent fuel pool will not drain following an SSE.

In the referenced Appendix 9-A analysis, the applicant evaluated the thyroid dose from two pools boiling. The analysis assumes that a seismic event has rendered the non-seismic spent fuel pool cooling system for each unit inoperable. By specific assumptions regarding refueling outage sequence, the RHR systems were assumed to be not available for spent fuel pool cooling. Additional assumptions were made regarding activity available for release. The analysis specifically did not credit iodine plateout or washout. The analysis description was silent with regard to the standby gas treatment system role in the event.

The RAI dated November 22, 1978, contained several additional questions, 010.8, 010.9, 010.10, 010.12, 010.13 and 010.14, regarding the design of the spent fuel pool and its cooling systems. Question 010.14 requested information regarding time to boil for various pool heat loads assuming cooling systems were not available. In reviewing the licensing basis, no further interaction between the applicant and the staff regarding the design of the spent fuel pool cooling system (with regard to safety grade or seismic Category I standards) was located.

A.4.2 Final Safety Analysis Report

The licensee's design and design bases regarding the spent fuel pool cooling system and other systems are documented in various sections of the FSAR. Pertinent FSAR sections are described below.

Section 3.1.2.4.15 of the FSAR describes the facility design conformance with General Design Criteria 44. In that section, the emergency service water system is described as providing cooling water to structures systems and components which are necessary to maintain safety during all normal and accident conditions. Makeup to the spent fuel pools is listed as one of the functions provided. In Section 9.2.5, the ESW system is described as having a safety related function and is described as being required to provide makeup to the spent fuel pool.

Section 3.1.2.6.2 of the FSAR describes the facility design conformance with GDC 61. The fuel pool cooling and cleanup system is described as providing reliable decay heat removal. Unlike Section 3.1.2.4.15 on GDC 44, this section of the FSAR does not contain a specific commitment to any system or systems as providing spent fuel pool cooling under accident conditions.

Section 9.1.3 of the FSAR describes the design of the spent fuel pool cooling system. Credit for operation of this system is not explicitly taken for any specific accident scenario. The SFPC system is non-seismic Category I, Quality Group C and are vulnerable to certain single active failures.

Appendix 9A describes the off-site consequences of a loss of SFP cooling. The analysis makes certain assumptions regarding the unavailability of systems to cool the spent fuel pool. The analysis made certain assumptions about the activity available for release from the spent fuel pool. For the analysis, the pools were assumed to boil and the effluent from the pools was assumed to be released directly to the environment, without credit for holdup within the secondary containment or filtration by the SGTS. No specific analysis regarding the effect of boiling pool vapors on equipment located within the reactor was performed. The licensee concluded that the off-site consequences of the specific analyzed event were acceptable. The analysis was performed in response to staff questions on the proposed non-seismic Category I design of the system.

A.4.3 Safety Evaluation Report

The staff documented its review and acceptance of the proposed SSES design in the SSES Safety Evaluation Report (SER) NUREG-0776, "Safety Evaluation Report Related to the Operation of Susquehanna Steam Electric Station, Units 1 and

2." Section 9.1.3 of the SER addressed the spent fuel pool cooling system design. The staff addressed the non-seismic Category I design of the SFP cooling system and based acceptance of that design on the availability of the redundant, seismic Category I ESW makeup capability and the availability of the standby gas treatment system. The SGTS was cited as meeting the provisions of RG 1.52. The staff also addressed conformance with the requirements of GDC 61 as it pertains to reduction in coolant inventory, citing the installation of siphon breakers and location of various penetrations. The SER concludes:

> To meet the makeup guidelines of Regulatory Guide 1.13, "Spent Fuel Storage Facility Design Basis," redundant seismic Category I sources of water are available, one from each emergency service water train. Based on our review as described above we concluded that the spent fuel pool cooling and cleanup system meets the guidelines of Regulatory Guide 1.13 regarding makeup to the spent fuel pool and the guidelines of Regulatory Guide 1.29 regarding design of non-seismic Category I systems and that the system design is in compliance with General Design Criteria 61 with regard to prevention of uncovering the spent fuel. We, therefore, conclude that the spent fuel pool cooling and cleanup system, is acceptable.

The staff did not cite, and apparently did not review, the design of the spent fuel pool cooling system to all of the guidance or standards listed in the existing SRP, including the decay heat removal aspects of GDC 61 or the standards of GDC 44. Thus ability to assure operation of the spent fuel pool cooling system under design basis LOCA conditions was not reviewed. However, the design of the system was found acceptable.

Section 3.2.1 of NUREG-0776 evaluated compliance of the SSES design to the requirements of GDC 2 related to seismic events. The SER noted six exceptions to the guidance of RG 1.29. The second of those, in Section 3.2.1(2) of the SER, determined that a non-seismic spent fuel pool cooling loop was acceptable based on the Seismic Category I makeup supply from the emergency service water system. Section 3.2.1(2) of the SER further states:

> The non-seismic Category I classification of the cooling loop at the fuel pool cooling and cleanup system is acceptable since the fuel handling area is ventilated by the seismic Category I standby gas treatment system which has engineered safety feature filters that meet the recommendations of Regulatory Guide 1.52, "Design, Maintenance, Testing Criteria for Atmospheric Cleanup Air Filtration and Adsorption Unit of Light-Water-Cooled Nuclear Power Plants."

Section C.1.a of RG 1.52 states:

> The design of an engineered-safety-feature atmospheric cleanup system should be based on the maximum pressure differential, radiation dose rate, relative humidity, maximum and minimum temperature, and other conditions resulting from the postulated

DBA and on the duration of such condition."

Section 3.1.2.4.15 of the SER states:

> "The emergency safeguard service water system, which comprises both the Emergency Service Water System and the Residual Heat Removal Service Water System, provides cooling water for the removal of excess heat from all structures, systems and components which are necessary to maintain safety during all abnormal and accident conditions. These include the standby diesel generators, the RHR pump oil coolers and seal water coolers, the core spray pump room unit coolers, RCIC pump room unit coolers, the HPCI pump room unit coolers, the RHR heat exchangers, RHR pump room unit coolers, emergency switchgear and load center room coolers, the control structure chiller and the fuel pool makeup."

Section 9.2.1 of the SER describes the above function of the ESW system and cites the above capability as a basis for compliance with GDC 44. The staff found the ESW system acceptable on this basis.

Finally, in Section 1.6 of the SER, the staff stated:

> Our evaluation included a review of the following information submitted by the applicants, particularly with regard to the following principal matters:
>
> (2) The design, fabrication, and testing and performance characteristics of the facility structures, systems and components important to safety. We have determined that they are in conformance with the Commission's General Design Criteria, quality assurance criteria, regulatory guides, and other appropriate rules, codes and standards and that any departures from these criteria codes and standards have been identified and justified.

A.4.4 Summary

The historical overview of spent fuel pool cooling design requirements presented above demonstrate that the staff did have requirements for safety grade design and seismic Category I design of spent fuel pool cooling systems in place at the time of the review of the Susquehanna operating license application. The staff did consider generic arguments with regard to acceptance of non-safety and non-seismic Category I designs. After consideration of these arguments, the staff concluded that, absent satisfactory analyses regarding off-site dose consequences of a pool heat-up or satisfactory analyses regarding prevention of pool boiling, spent fuel pool cooling system designs should be safety grade and seismic category I.

The staff was clearly notified of applicant's intention to construct the spent fuel pool cooling system to non-seismic Category I, Quality Group C standards. The staff asked questions on the proposed non-seismic Category I design with regard to release of radioactivity to the environment during a boiling event. The licensing basis review did not uncover evidence that the impact of boiling

on safety systems inside secondary containment was specifically evaluated by the staff during the Susquehanna licensing review. Nevertheless, the staff had ample opportunity to consider the effects of a non-safety grade, non-seismic Category I design. At the completion of the design review, the staff did conclude the non-safety grade, non-seismic Category I spent fuel pool cooling design was acceptable. Although the staff apparently deviated from its own acceptance criteria in reaching this conclusion, the staff's statements in NUREG-0776 on the acceptability of the system design establish an applicable staff position.

A.5 Backfit Considerations

The Backfit Rule, 10 CFR 50.109, defines what staff actions are considered backfits and imposes requirements on the staff for evaluation and documentation of backfits. More detailed guidance on implementation of 10 CFR 50.109 is spelled out in NUREG-1409, "Backfitting Guidelines" (Attachment 3). The backfit rule states:

> Backfitting is defined as the modification of or addition to systems, structures, components or design of a facility; or the design approval or manufacturing license for a facility; or the procedures or organization required to design, construct or operate a facility; any of which may result from a new or amended provision in the Commission rules or the imposition of a regulatory staff position interpreting the Commission rules that is either new or different from a previously applicable staff position...

NUREG-1409 provides further guidance on what constitutes an applicable staff position. An applicable staff position is a requirement or position already specifically imposed on or committed to by a licensee. Such positions include NRC staff positions that are documented explicit interpretations of more general regulations and are contained in documents such as the Standard Review Plan, branch technical positions, regulatory guides, generic letters and bulletins.

A.6 Additional Licensing Issues

By letter dated March 21, 1994 and May 10, 1994, the authors of the Part 21 report requested the staff consider several additional issues with regard to the licensing basis conclusions. Certain of those considerations are addressed below:

A.6.1 Radiological Licensing Basis Considerations

The determination that the proposed design was acceptable and in compliance with the Commission's requirements is documented in the operating license safety evaluation for a facility and is itself an "applicable staff position." In light of the availability of information regarding proposed spent fuel pool cooling design at the time of the licensing review, a change in the staff's finding of acceptability represents a backfit. Such a backfit could not be justified as a compliance backfit since the applicable staff position in the

SER establish the original basis for compliance upon which the Commission issued the operating license. Thus any finding that the design or acceptance should be modified must follow a demonstration that design does not continue to provide adequate protection or a demonstration that significant safety benefit could be derived, at reasonable cost, from the modification.

In the November 27, 1992, Part 21 Report concerning the potential substantial safety hazard resulting from a loss of spent fuel pool (SFP) cooling, the authors expressed concern that the dose associated with a postulated radionuclide release consistent with Regulatory Guide 1.3 resulting from a LOCA, including the postulated airborne radioactive source, would preclude any operator actions within the reactor building to restore cooling or provide make-up water to the SFP.

Design basis analyses, submitted as part of a reactor license application, are stylistic calculations intended to demonstrate that the design meets the applicable requirements in Title 10 of the Code of Federal Regulations (CFR). To assist the applicant with these calculations, the NRC staff has provided Regulatory Guides (RG) and NUREG publications documenting analysis methods and assumptions acceptable for the respective analysis. In each case the staff guidance provides conservative parameters which produce results that reasonably bound the "actual" consequences of the issue or accident being analyzed. The assumptions that are adopted in the design basis calculations become part of the technical basis on which the NRC grants the operating license (licensing basis). The design basis assumptions that are conservative and appropriate for one analysis may not be appropriate for the analysis of a different aspect of the design (e.g., for the design basis analysis of a certain accident sequence it may be conservative to assume a certain valve fails closed; however, it may not be conservative or appropriate to assume that the same valve is closed for some other analysis evaluating the plant response during a different assumed event).

The NRC has provided guidance in RG 1.3 on acceptable methods and assumptions for evaluating off-site radiological consequences of a design basis accident (LOCA) at a BWR to demonstrate compliance with the plant site criteria in 10 CFR Part 100. The assumptions given in RG 1.3 include the fraction of the radioactivity in the reactor core that is released into the reactor containment, the timing of that radioactivity release into containment, the transport of radioactivity through the reactor plant (containment leakage, hold up, filtration, radiological decay,etc.), atmospheric diffusion models acceptable for determining the dilution and transport of the radioactive plume off-site, and acceptable dose conversion factors for determining radiation dose to the public. The fraction of radioactivity released from the reactor core (source term) in RG 1.3 is based on the guidance in Technical Information Document (TID) 14844.

Following the March 28, 1979, accident at Three Mile Island Unit 2 (TMI-2), the staff recognized that the licensing basis of the nuclear power plants operating at that time did not adequately address the potential for in-plant radiological conditions to preclude operators from taking necessary actions during a LOCA. One of the many items the TMI-2 Lessons Learned Task Force identified is that systems carrying reactor water outside the primary

containment may become significant sources of in-plant radiation during a degraded core accident. In response to the Lessons Learned Task Force recommendations documented in NUREG 0578, the NRC issued NUREG 0737 as a Generic Letter that required all licensees of operating plants, applicants for operating licenses, and construction permit holders to implement certain of those recommendations. These backfits became part of the licensing basis for these plants. Item II.B.2 of NUREG 0737, "Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems Which May Be Used in Post-accident Operation," specifies the analysis and assumptions to demonstrate that operators can access those areas of the plant necessary "to aid in the mitigation of or recovery from an accident" (vital area). The source term specified in item II.B.2 is based on the TID 14844 release fractions and is therefore, as stated in II.B.2, "equivalent" to the source term recommended in Regulatory Guide 1.3. Using this assumed source term, the licensee is required to demonstrate by calculations that the shielding provided by the plant design is adequate to allow operators to take the actions necessary in each vital area during the postulated accident without exceeding 5 rem whole body, or its equivalent to any part of the body (the design criteria in GDC 19).

NUREG 0737 does not state (strictly, RGs and NUREGs do not contain requirements) that all of the assumptions of RG 1.3 (including activity release timing, containment leakage or presence of airborne radioactivity in the reactor building) are to be incorporated into the shielding design review. The TMI-2 Lessons Learned Task Force considered the issue of the radiological impact of a potential airborne radioactive source during a degraded core accident, but could not justify backfitting any such consideration into the licensing basis of the operating plants. The resolution of this issue was left for a Commission decision as part of the proposed severe accident rulemaking. In its Policy Statement on Severe Reactor Accidents Regarding Future Designs and Existing Plants (Ref. 5), the Commission concluded that additional requirements to address severe accidents were not warranted. Therefore, consideration of an airborne source term (inferred from the RG 1.3 assumptions or otherwise) in the analysis to demonstrate plant access (NUREG 0737 II.B.2) is not required and is not contained in the Susquehanna licensing or design basis.

A.6.2 Ultimate Heat Sink Volume Considerations

Table 9.2.8 of the SSES FSAR lists the spray pond water allowances for the ultimate heat sink. Item "h" in that table lists an allowance of 5 X 10^6 gallons for fuel pool makeup. Section 9.2.7 of the FSAR states that the ultimate heat sink is capable of providing enough cooling water without makeup, for a design basis LOCA in one unit with the simultaneous shutdown of the other unit, for 30 days while assuming a concurrent SSE, single failure, and loss of off-site power. The volume allowance for fuel pool makeup is consistent with that required to compensate for boiling of the spent fuel pools (60 gpm per pool). The 5 X 10^6 gallon allowance represents a conservative sizing consideration for the UHS. As described in section A.XX, makeup to the spent fuel pools under accident considerations is a function assumed in the licensing basis. As stated previously, the staff licensing review found the spent fuel pool cooling system design acceptable without referencing any specific event other than a seismic event and without citing any of the existing acceptance criteria that would ensure functioning of the system during design basis LOCA events. The licensing basis' failure to address scenarios other than seismic events or address particular acceptance criteria does not imply that boiling was assumed as a cooling mechanism for the stored spent fuel for other design basis events.

A.6.3 Reactor Building Heat Loads

Section 6.2 of the FSAR describes the design considerations for secondary containment. The FSAR states that heat loads from operating equipment and heat transferred through primary containment boundaries was considered. The licensee indicated that heat loads considered include a contribution from the spent fuel pool. The contribution from the fuel pool is limited to sensible heat and does not include the latent heat of vaporization associated with boiling. As with the ultimate heat sink volume sizing considerations, specification of an assumed spent fuel pool temperature was appropriate for calculating reactor building post-LOCA heat loads if some method of forced pool cooling is assumed. However, although the applicant did not specify a system or systems that would assure cooling to the spent fuel pool under design basis LOCA condition, it is not specifically implied that pool boiling was the assumed cooling mechanism. As discussed above, the staff found the design of the spent pool cooling system acceptable without specifying what form of pool cooling following a design basis LOCA formed the licensing basis for that system or for the facility as a whole. Similarly, the staff found the secondary containment design acceptable in Section 6.2.3 of NUREG-0776

A.6.4 Load Shed Procedural Considerations

The staff examined the adequacy of the safety evaluation performed by the licensee pursuant to 10 CFR 50.59 regarding the implementation of procedure EP-IP-055 in October 1988. The staff documented the results of that review in Inspection Report XX/XXX.