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Nuclear LLC

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10 CFR 50.90

LR-N10-0097
LAR H10-03

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Hope Creek Generating Station
Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: **License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension**

In accordance with the provisions of 10 CFR 50.90, PSEG Nuclear, LLC (PSEG) hereby requests an amendment of the Technical Specifications (TS) for the facility operating license listed above.

This license amendment request proposes changes to TS 3/4.8.1, "AC Sources – Operating"; specifically ACTION b concerning one inoperable Emergency Diesel Generator (EDG). The proposed change would extend the Allowed Outage Time (AOT) for the 'A' and 'B' EDGs from 72 hours to 14 days. The proposed extended AOT is based on application of the Hope Creek Generating Station (HCGS) Probabilistic Risk Assessment (PRA) in support of a risk-informed extension, and on additional considerations and compensatory actions. The risk evaluation and deterministic engineering analysis supporting the proposed change have been developed in accordance with the guidelines established in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decision-making: Technical Specifications," and NRC Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."

This Technical Specification change is being requested to allow sufficient time to perform adequate preventive maintenance to ensure diesel generator reliability and availability. The proposed changes would reduce EDG unavailability by allowing on-line performance of EDG maintenance activities in a single outage versus multiple outages, or during refueling outages. The proposed changes also provide flexibility to resolve EDG deficiencies and avoid potential unplanned plant shutdown, along with the potential challenges to safety systems during an unplanned shutdown, should a condition occur requiring EDG corrective maintenance.

PSEG has determined that this LAR does not involve a significant hazard consideration as determined per 10 CFR 50.92. PSEG's technical and regulatory evaluation of this LAR, the

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TS changes, and the TS Bases changes (for information only), are provided in Attachments 1, 2 and 3. Attachment 4 provides the Technical Evaluation of Extending the Hope Creek Diesel Generator AOT Using Probabilistic Risk Assessment Models. Attachment 5 summarizes the formal regulatory commitments pending NRC approval of the proposed amendment.

PSEG requests approval of this LAR within one year of the submittal date. Once approved, the amendment will be implemented within 60 days from the date of issuance.

These proposed changes have been reviewed by the Plant Operations Review Committee. In accordance with 10 CFR 50.91, "Notice for Public Comment; State Consultation," a copy of this application, with attachments, is being provided to the designated State Official.

Should you have any questions regarding this submittal, please contact Mr. Jeff Keenan at (856) 339-5429.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on March 29, 2010
(Date)

Sincerely,

John F. Perry

John F. Perry
Site Vice President - Hope Creek

Attachments (5)

CC

S. Collins, Regional Administrator - NRC Region I
R. Ennis, Project Manager - USNRC
NRC Senior Resident Inspector – Hope Creek
P. Mulligan, Manager IV, NJBNE
Commitment Coordinator – Hope Creek
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LICENSE AMENDMENT REQUEST (LAR) H10-03
Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension

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1.0 DESCRIPTION

This license amendment request proposes changes to the Hope Creek Generating Station (HCGS) Technical Specifications (TS); specifically, TS 3/4.8.1, "AC Sources – Operating", ACTION b, concerning one inoperable Emergency Diesel Generator (EDG). The proposed change would extend the Allowed Outage Time (AOT) for the 'A' and 'B' EDGs from 72 hours to 14 days. The proposed new AOT is based on application of the HCGS Probabilistic Risk Assessment (PRA) in support of a risk-informed extension, and on additional considerations and compensatory actions. The risk evaluation and deterministic engineering analysis supporting the proposed change have been developed in accordance with the guidelines established in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decision-making: Technical Specifications" (Reference 1), and NRC Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" (Reference 2).

This Technical Specification change is being requested to allow sufficient time to perform adequate preventive maintenance to ensure diesel generator reliability and availability. The proposed changes would reduce EDG unavailability by allowing on-line performance of EDG maintenance activities in a single outage versus multiple outages, or during refueling outages. The proposed changes also provide flexibility to resolve EDG deficiencies and avoid potential unplanned plant shutdown, along with the potential challenges to safety systems during an unplanned shutdown, should a condition occur requiring EDG corrective maintenance.

2.0 PROPOSED CHANGE

TS 3/4.8.1, ACTION b would be revised as follows extending the AOT for the A and B EDGs to 14 days:

> With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours* unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated. If continued operation is permitted by LCO 3.7.1.3, restore the inoperable diesel generator to OPERABLE status ~~***within 72 hours for diesel generators A or B, or***~~ within 14 days ~~***for diesel generators C or D***~~, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

Attachments 2 and 3 provide the marked-up TS pages and associated TS Bases pages. The Bases pages are being submitted for information only and do not require issuance by the NRC. PSEG will implement the TS Bases changes in accordance with the HCGS TS Bases Control Program.

3.0 BACKGROUND

3.1 HCGS AC Electrical Power System

The Hope Creek 500Kv Ring Bus is energized by three offsite sources (Red Lion 5015, New Freedom 5023, and Salem X-Tie 5037). From these three offsite sources the station is supplied with two physically independent circuits between the offsite transmission network and the onsite Class 1E Distribution network as follows. Two 500 Kv feeds (10X and 20X) into a split 13.8Kv Yard, with each feed supplying power to an energized separate Station Service Transformer (AX501 and BX501). Transmission lines meet or exceed design requirements set forth by the National Electrical Safety Code and agree with Lower Delaware Valley 500-kV Transmission Design Criteria. Lines meet the Army Corps of Engineers requirements for clearance over flood levels. All bulk power transmission lines are designed to withstand 100 mph wind loads on bare conductors. The transmission network provided for the Hope Creek plant complies with General Design Criteria (GDC) 17 and 18 of Appendix A to 10CFRPart 50.

The Onsite Power Systems consist of AC and DC power systems. The onsite AC power systems include a Class 1E system and a non-Class 1E system.

The Class 1E power system supplies all Class 1E loads that are needed for safe and orderly shutdown of the reactor, maintaining the plant in a safe shutdown condition, and mitigating the consequences of an accident. In addition to Class 1E loads, the Class 1E system supplies power, through isolation devices, to a limited number of non-Class 1E loads that are important to the integrity of the power generating equipment. Isolation between Class 1E power supply buses and the non-Class 1E loads is achieved by tripping the Class 1E breaker under a LOCA condition. This is in accordance with IEEE 384-1981, Paragraph 7.1.2.2.

The Class 1E AC power system distributes power at 4.16 kV, 480 V, and 208/120 V. The Class 1E power system is divided into four independent channels. Each power system channel supplies power to loads in its own load group. Each Class 1E 4.16 kV bus is provided with connections to the two offsite power sources via Station Service Transformer 1AX501 and 1BX501. One of these sources is designated as the normal source and the other as the alternate source for the bus. In addition to these two connections to the offsite power, each of the 4.16-kV Class 1E buses is connected to its dedicated emergency diesel generator (EDG). These four EDGs (A, B, C and D) serve as the standby electric power source for their respective channels in case both the normal and alternate power supplies to a bus are lost.

Each Class 1E 4.16-kV bus is provided with a normal and an alternate offsite power supply feeder and one EDG feeder. Each bus is normally energized by the normal power supply. If the normal power is not available at the 4.16 kV bus due to transformer or transformer feeder protective relay actuation, automatic fast transfer to the alternate source occurs. If the normal power supply is lost due to degraded grid conditions (i.e., bus voltage less than 92 percent of rated volts for greater than 20 seconds) or a loss of voltage (i.e., bus voltage less than 70 percent), a slow or dead bus transfer to the alternate source takes place. If both the normal and the alternate power sources are unavailable, the loads on each bus are picked up automatically by the EDG assigned to that bus in a predetermined sequence.

The standby power supply for each of the four safety-related load groups consists of one EDG complete with its auxiliaries, which include the cooling water, starting air, lubrication, intake and exhaust, and fuel oil systems. The sizing of the EDGs and the loads assigned among them is such that any combination of three out of four of these EDGs is capable of shutting down the plant safely, maintaining the plant in a safe shutdown condition, and mitigating the consequences of accident conditions.

In the scenario of a loss-of-offsite power (LOOP) event, each EDG will receive an automatic start signal. Following load shedding and bus isolation, each EDG output breaker will automatically close, energizing the associated 1E Bus. Essential loads will then be automatically connected to their respective 1E buses sequentially.

Each EDG receives a start signal on the following signals:

1. Unacceptable degradation of voltage at the respective 4.16-kV Class 1E bus with which the EDG is associated. Unacceptable degradation of voltage implies one or both of the following conditions:

   a. Voltage at both the preferred incoming feeder breakers is less than 92 percent of normal voltage for 20 seconds

   b. Bus voltage is less than 70 percent of normal and the voltage at both the preferred incoming feeder breakers is less than 92 percent of normal voltage.

2. Receipt of an Emergency Core Cooling System (ECCS) actuation signal from the Core Spray System. This signal is generated by low reactor water level (L1), or high drywell pressure initiation.

3. Manual initiation of the Core Spray System.

4. Manual actuation of switches at the local or remote control panels, and in the main control room.

Each EDG is rated at 4430 kw for continuous operation and at 4873 kw for 2 hours of short time operation in any 24-hour period. The continuous rating of the EDG is based on the maximum total load required at any one time. Each EDG is connected exclusively to its dedicated 4.16-kV Class 1E bus. Each of the four Class 1E power supply channels feed loads in its own dedicated load group. No provisions exist for parallel operation of the EDG of one channel with the EDG of a redundant channel.

3.2 Station Blackout Capability

Station blackout (SBO) refers to a complete loss of all alternating current (AC) electric. The SBO rule (10 CR 50.63) requires utilities to assess the impact of a loss of preferred power (offsite power) concurrent with a loss of the unit's emergency diesel generators. Hope Creek Generating Station (HCGS) SBO analysis has been performed in accordance with the guidelines provided in Regulatory Guide 1.155,"Station Blackout," and NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives addressing Station Blackout at Light Water Reactors" for assessment of HCGS's compliance with the requirement of 10CFR 50.63. HCGS has not utilized an alternate AC source operation approach; instead the assessment used the "AC-Independent" approach outlined in NUMARC 87-00 for its coping capability. In this approach, plants rely on available process steam, DC power, and compressed air to operate equipment necessary to achieve and maintain hot shutdown. The required SBO coping duration for HCGS is calculated as four hours in accordance with the guidance provided in NUMARC 87-00, Section 3.0.

EDG reliability is calculated based on NSAC-108 criteria and is considered to be 0.95 for HCGS. The reliability is defined in terms of the number of failures in 20, 50 or 100 demands. HCGS monitors the EDG reliability under the Maintenance Rule Program (see Section 3.4). Increasing the EDG AOT will not have any impact on the EDG target reliability used in the SBO coping time calculation at HCGS.

The SBO analysis establishes that adequate condensate inventory will be available for decay heat removal, the plant class 1E batteries have adequate capacity to supply all SBO DC and inverter loads for four hours with no manual stripping (some stripping of loads is performed to reduce room heating effects). SBO equipment operability is maintained in rooms with elevated temperatures resulting from loss of ventilation, containment isolation capability is maintained to ensure containment integrity, and the plant compressed air system is not essential to cope with SBO conditions. The results provide adequate assurance that HCGS will be able to withstand and recover from an SBO event for a coping duration of four hours.

The SBO assessment documents the station's ability to cope with a four-hour SBO, with subsequent restoration of AC power. Consistent with the recommendations of NUMARC 87-00, the High Pressure Coolant Injection (HPCI) and Reactor Containment Isolation Cooling (RCIC) decay heat removal systems, which operate independent of AC power, were selected and utilized in HCGS's analyses.

Areas containing equipment necessary to cope with a SBO event were evaluated for the effect of loss-of-ventilation due to a SBO. The evaluation showed that equipment operability remained bounded due to conservatism in the existing design and qualification bases. Battery capacity is adequate for HPCI/RCIC operation. In addition, adequate compressed gas capacity exists (via accumulators) to support main steam relief valve actuations. The current condensate tank (CST) inventory reserve (135,000 gallons), for HPCI/RCIC use, ensures that adequate water volume is available to remove decay heat, depressurize the reactor, and maintain reactor vessel level above the top of active fuel (TAF) (109,000 gallons required).

3.3 Emergency Diesel Generator Reliability Program

HCGS maintains an Emergency Diesel Generator Reliability Program per PSEG station procedures. The program monitors and evaluates EDG performance and reliability consistent with guidance provided in Revision 1, Appendix D and E of NUMARC 87-00, "Guidelines for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." The program requires remedial actions when one or more established reliability "trigger values" are exceeded, then a root cause evaluation is performed and corrective actions taken. Based on Station Blackout studies and coping criteria, the EDG reliability target for Hope Creek is 0.95. This value represents the underlying unit EDG reliability values for purposes of establishing a coping duration of four hours for a Station Blackout Event. Hope Creek EDG reliability remains high with only one failure to start on demand in the last 36 months. This December 2009 event was due to high D EDG generator voltage after start.

The EDG reliability program will not be negatively impacted by the proposed amendment because EDG testing frequencies are unaffected. Overall, the AOT extension is expected to improve EDG availability even though additional maintenance activities normally scheduled during plant outages, may be performed online. A significant portion of online EDG maintenance windows are associated with the preparation and restoration activities including tagging, jacket water & lube oil system drain down, jacket water & lube oil system fill and vent, system restoration & lineup, warm up period for standby conditions, and post maintenance testing. The durations for these maintenance support activities are fairly consistent. A longer AOT duration will allow more maintenance to be accomplished for a given maintenance window, thereby reducing the number of EDG outages for the A and B EDGs. Therefore, the total EDG unavailability is expected to decrease with this proposed amendment.

It should be noted that using the full duration of the requested 14 day AOT would be infrequent (other PSEG programs insure the extended AOT would not be abused). Frequent use of the full AOT duration would adversely impact EDG unavailability, which could result in exceeding MR goals, require corrective actions, and increased management attention to restore the EDGs to Maintenance Rule (a)(2) status.

3.4 Maintenance Rule Program

The Maintenance Rule (MR) requires that an evaluation be performed when equipment covered by the MR does not meet its performance criteria. The reliability and availability of the EDGs are monitored under the MR program. If the pre-established reliability or availability performance criteria are not achieved for the EDGs, they are considered for 10 CFR 50.65 (a)(1) actions. These actions would require increased management attention and goal setting in order to restore their performance to an acceptable level. The actual out of service time for the EDGs is minimized to ensure that the reliability and availability performance criteria are met.

The Hope Creek EDG MR status is (a)(2), with a 36-month rolling average unavailability of 1.21% (through February 2010). In addition, the system is MSPI Green with no low margin risk. The EDG MR status is not expected to be adversely impacted by the proposed amendment because fewer extended planned outages, will offset the current multiple short planned outages for the A and B EDGs.

3.5 Configuration Risk Management Program (CRMP)

Plant configurations and changes in plant configurations are assessed for risk at HCGS. In accordance with station procedures, when risk significant SSCs, such as Emergency Diesel Generators, are made unavailable, actions are taken to protect redundant / diverse Structures, Systems and Components (SSCs). PRA based risk assessments are performed for all planned plant configurations as part of the work planning process. These configurations are pre-planned so as to minimize the risk. If unplanned equipment unavailability occurs during Emergency Diesel Generator maintenance activities, station procedures direct that the risk be re-evaluated, and if found to be unacceptable, compensatory actions are taken until such a time that the risk is reduced to an acceptable level. Specific risk thresholds are procedurally specified for the assessment of the need for compensatory actions. If compensatory actions are insufficient, then procedural direction is to transition to a mode or other specified condition that reduces overall plant risk to an acceptable level.

3.6 Current TS Requirements and Limitations

TS 3/4.8.1 requires, as a minimum, two physically independent AC circuits between the offsite transmission network and the onsite Class 1E distribution system, and four separate and independent diesel generators. With one EDG inoperable, restoration within 72 hours is required for the A and B EDGs, or within 14 days for the C and D EDGs.

HCGS Amendment 75 (ADAMS ML011770266) dated August 1, 1995, granted the extension of the C and D EDG AOT to 14 days. The PSEG amendment request that resulted in Amendment 75 had also requested an extension of the AOT for the A and B EDGs. However in the Safety Evaluation for Amendment 75, the NRC staff stated: *"Because of the greater importance of EDGs A and B [power source for the RHR pumps], the staff is concerned with extending the AOT for these EDGs. As a result, the staff informed the licensee that a maximum of 14 days AOT will be allowed for EDGs C and D only, provided certain conditions are met. EDGs A and B will continue to have a 72-hour AOT."* Section 4 of this Attachment 1 addresses and evaluates this concern with extending the AOT of the A and B EDGs.

Planned EDG outages, including preventive maintenance to ensure EDG availability, elective maintenance activities, and surveillances, routinely require more than 72 hours to complete. As such, iterative maintenance windows of shorter duration are scheduled to accomplish appropriate maintenance for the A and B EDGs. In addition emergent maintenance and subsequent testing could be completed in the AOT. Replacement of equipment such as bearings and pistons require significant run in time and surveillance testing, challenging the ability to complete maintenance activities within the current AOT. Typically these longer duration activities, including diesel overhauls, have had to be scheduled during refueling outages. Performing these activities on-line allows the focus of the maintenance organization and site management on these critical tasks.

The extended AOT for EDGs also improves effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. Longer required AOT durations allows more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency. Thus, the total EDG unavailability is expected to be reduced with this proposed change.

4.0 TECHNICAL ANALYSIS

This section provides the technical analysis of the proposed changes with regard to the principles that adequate defense-in-depth is maintained, sufficient safety margins are maintained, and the calculated increases in core damage frequency (CDF) and large early release frequency (LERF) are small and consistent with the guidance of RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases," dated November 2002 and RG 1.177, "An Approach for Plant- Specific, Risk-Informed Decision making: Technical Specifications," dated August 1998 (References 1 and 2).

4.1 Current Licensing Basis for EDG Allowed Outage Time

Under the current TS, if either the A or B EDGs is inoperable, action is taken to restore the EDG to operable status within 72 hours. In this Condition, the three remaining operable EDGs and offsite to onsite paths are adequate to supply electrical power to the onsite ESF division. The 72 hour AOT takes into account the capacity and capability of the remaining AC sources.

4.2 Proposed TS 3.8.1 Changes and Benefits

The proposed changes will allow, for EDG A and B, an AOT of 14 days for maintenance or testing activities. This will permit an additional 11 days beyond the current TS allowed AOT of 72 hours and avoid or minimize TS required plant shutdowns due to EDG maintenance or testing.

The extended TS AOT for the A and B EDGs improves effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. Longer AOT durations allow more maintenance to be accomplished during a given on-line maintenance period and therefore, would improve maintenance efficiency. Thus, the total EDG unavailability is expected to be reduced with this proposed change.

A historical review of EDG preventative and corrective maintenance shows that the longest duration maintenance outages are due to engine and generator preventive maintenance. The 24-month engine and generator preventive maintenance system outages have a typical duration of three to five days. The 15-year engine cylinder liner o-ring replacement preventive maintenance duration has been completed in approximately 200 hours or 8.3 days. With regard to corrective maintenance, a single cylinder liner/piston replacement and retests required 187 hours. Specific maintenance activities that tune and/or replace the EDG governor components require a Large Load Reject functional test. This test has been successfully completed online after replacing a mechanical governor in August 2009, and again in March 2010 after tuning an EGA electronic governor. There were no 1E 4160 VAC bus voltage transients resulting from on-line Large Load Reject functional testing.

This change will allow some maintenance activities to be performed on-line which would otherwise require performance during a refueling outage. On-line preventive maintenance and scheduled overhauls provide the flexibility to focus more quality resources on any corrective or elective diesel generator maintenance. For example, during refueling outages, resources are required to support many system outages; and during on-line maintenance, plant resources are focused on the EDG overhaul.

Performance of more EDG maintenance on-line will improve EDG availability during plant refueling outages. Performing EDG overhaul activities on-line should reduce the risk and synergistic effects on risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

4.3 Deterministic Assessment of Proposed EDG AOT Extension

The effect of this LAR would be to allow continued power operation up to an additional 11 days while EDG maintenance or testing is performed. The EDG is a standby electrical power supply whose safety function is required when both the normal and alternate off-site power supplies are unavailable and there is an event that requires operation of the plant emergency safeguards features.

Independent standby power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems. The standby power source is designed with adequate independency, redundancy, capacity, and testability to ensure power is available for the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source will successfully provide this capacity when a failure of a single active component is assumed.

Each of the four EDGs can supply one of the four separate Class 1-E system buses. Each is started automatically on a Loss of Off-site Power (LOOP) or Loss of Coolant Accident (LOCA). The EDG arrangement provides adequate capacity to supply the engineered safety features for the DBA, assuming the failure of a single active component in the system.

Since the standby power systems can accommodate a single failure, extending the AOT for an out of service EDG has no impact on the system design basis. Safety analyses acceptance criteria as provided in the UFSAR are not impacted by this change. AC power sources credited in the accident analyses will remain the same.

To ensure that the single failure design criterion is met, Limiting Conditions for Operation (LCOs) are specified in the plant TS requiring all redundant components of the onsite power system to be operable. In the event that an EDG is inoperable in operating Modes 1, 2, and 3, existing TS 3.8.1.1 ACTION b requires that the with one EDG inoperable, demonstrate the OPERABILITY of the required independent A.C. offsite sources. When the required redundancy is not maintained, action is required within a specified time period, referred to as the AOT, to initiate a plant shutdown and place the plant in a safe condition. The AOT provides a limited time to restore equipment to operable status and represents a balance between the risk associated with continued plant operation with less than the required system or component redundancy and the risk associated with initiating a plant transient while transitioning the unit to a safer condition (e.g., cold shutdown). Thus, while the AOTs provided in the plant TS are designed to permit limited operation with temporary relaxation of the single failure criterion, the acceptability of the maximum length of the AOT interval relative to the potential occurrences of design basis events needs to be considered. Since extending the AOT for a single inoperable EDG does not change the design basis for standby EDG power, the risk impact of EDG unavailability during the extended AOT interval (days 4 through 14 of the proposed 14 day AOT) must be evaluated quantitatively using a probabilistic approach.

Hope Creek's coping time of four hours during SBO is not affected by the proposed change. The four hour coping time is calculated based on guidance provided in NUMARC 87-00, Rev. 1.

The assumptions and the results of the SBO analyses are not changed by an extension of the AOT, and compliance with 10 CFR 50.63 will be maintained as it does not impact the reliability of the EDGs. In addition, EDG reliability is maintained at or above the SBO target level (0.95), and the effectiveness of maintenance on the EDGs and support systems is monitored pursuant to the Maintenance Rule.

Based on the above discussion, extending the AOT for a single inoperable EDG from 72 hours to 14 days is acceptable because the proposed change will not impact the plant design basis. The impact of extended plant operation with less than the required equipment redundancy is evaluated in a probabilistic framework in the discussions that follow.

To ensure that the risk associated with extending the AOT for an EDG is minimized, and consistent with the philosophy of maintaining defense in depth, compensatory measures will be applied when removing an EDG from service as described in Section 4.5.1. These measures will ensure the risks associated with removing an EDG from service are managed to minimize the increase in risk during the out of service time.

If this LAR is not granted, A or B EDG inoperability would require a plant shutdown following 72 hours in current TS 3.8.1.1 ACTION b. Shutdown of the plant involves many plant operator activities and plant evolutions. These activities and evolutions provide challenges to plant equipment, opportunities for operator errors and increase the possibility of a plant trip. It should also be noted that shutdown of a unit does not remove the desirability of having the EDG available to support its associated 1E bus, but rather places additional dependence on the operable Class 1E bus by requiring operation of the residual heat removal system. By granting this LAR and allowing continued steady state operation, additional operator activities and plant operations evolutions associated with plant shutdown could be avoided. The increased possibility for plant trip may also be avoided. This LAR proposes an additional 11 days as a reasonable time for which a regulatory basis exists for AOT extension. This additional time period is considered small. Due to the short time period, the probability of a design basis accident occurring during this interval is low.

4.4 Asymmetry of the EDGs

As discussed in Section 3, PSEG previously requested an extended AOT for the A and B EDG. Because of the asymmetry of the EDGs and relationship of EDGs A and B to the RHR pumps, the NRC did not permit the requested extension (Amendment 75). PSEG has re-examined the EDG asymmetry; there is some degree of asymmetry among the EDGs, but is judged to be reasonable given an examination of the plant design and the Hope Creek 2008 PRA model. The following discusses this asymmetry and how it compares with the 1994(1) analysis.

Model development and improvements of the Hope Creek PRA have occurred over the past 20 years. Plant configuration changes and operating strategies have also contributed to improvement in margins as measured by the PRA risk metrics. The PRA used in the 1994 LAR submittal resulting in the C and D EDG AOT extension to 14 days was slightly conservative in several areas.

One of these areas is the treatment of the loss of containment heat removal accident sequences. The treatment in 1994 included greater reliance on the suppression pool cooling

(1) 1994 was the time frame for the EDG C and D AOT Extension Request.

function, which under LOOP conditions, is ultimately limited by the A and B EDGs. This conservative bias was, in turn, reflected in slightly higher risk metrics associated with the A and B EDGs compared with the C and D EDGs in the 1994 PRA. The PRA update in 2008, which was performed and Peer Reviewed using the ASME PRA Standard as endorsed by RG 1.200, Rev. 1, eliminated most of this conservative bias to allow a realistic assessment of these long term loss of Decay Heat Removal (DHR) sequences.

The 2008 PRA model reduced the risk importance of EDG A and B due to reduced importance of the RHR suppression pool cooling/SDC function. However, the 2008 PRA concurrently increased the EDG B and D risk importance due to a modeling change to require the availability of the DC battery chargers to support the 24-hour PRA mission time for SRV operation. The SRVs are dependent on 125V DC power from Div. B and D, which are supported by EDG B and D, respectively.

The 2008 PRA results show that the B and D EDGs are of potentially higher risk significance (larger risk increase for OOS conditions) than the A and C EDGs. These differences reflect a different asymmetry than that perceived in 1994. Nevertheless, this asymmetry is not considered significant for the extension of the AOT, but it demonstrates the impact of removing the biases in the 1994 PRA model.

As discussed in the following sections, it is shown by using the RG 1.174 and RG 1.177 acceptance guidelines and the 2008 PRA that all 4 EDGs are justified to have a 14 day AOT.

4.5 Risk Assessment

Hope Creek intends to perform a planned major overhaul at a frequency of no more than once per EDG per 24 month PM cycle. Beyond that, Hope Creek shall continue to minimize the time periods to complete any required maintenance. Plant configuration changes for required maintenance of the EDGs as well as the maintenance of equipment having risk significance are managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the risk of a severe accident.

The proposed changes are evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increase in core damage frequency (CDF) and large early release frequency (LERF) is small and consistent with the NRC Safety Goal Policy Statement, USNRC, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995.

The justification for the use of an EDG extended AOT is based upon risk informed and deterministic evaluations consisting of three main elements:

> <u>Tier 1: Assessment of the impact of the proposed TS change using a valid and appropriate PRA model and compare with appropriate acceptance guidelines</u>. The modeling approach is consistent with the NRC guidance for the calculation of the requested risk measures using the Hope Creek PRA for internal events, internal floods, fire hazards, and seismic sequences. Regulatory Guide 1.177 is followed to calculate the change in risk measure for ICCDP and ICLERP. These conditional probabilities are performed to calculate the risk change while in the EDG AOT for each EDG case. As part of the Tier 1 analysis for the EDG AOT risk assessment, an

integrated assessment of the impact of the AOT extension is calculated assigning the "worst case" diesel unavailability to both the A and B diesel generators. This calculation is then used for comparison with the criteria set in Reg. Guide 1.174.

Tier 2: Evaluate equipment relative to the contribution to risk while the EDG is in the extended AOT. Examination of out of service combinations can be evaluated for their risk significance to determine if additional measures may be required.

Tier 3: Implementation of the Configuration Risk Management Program (CRMP) while an EDG is in an extended AOT. The CRMP is used for scheduling of station maintenance activities and helps ensure that there is no significant increase in plant risk due to a severe accident while any EDG maintenance is performed. These elements provide adequate justification for approval of the requested Technical Specification change by providing a high degree of assurance that power can be provided to the ESF buses during the EDG extended AOT for all Design Basis Accidents (DBAs) (i.e., Loss of Offsite Power, Loss of Coolant Accident (LOCA)), Station Black-out (SBO), or fire during the EDG extended AOT.

The Tier 1 and Tier 2 evaluations are provided in Attachment 4. Tier 3 is discussed in Section 3.5. Attachment 4 also includes documentation demonstrating that the Hope Creek internal events PRA is a thorough and detailed PRA model that is robust and capable of supporting the risk-informed decision to increase the A and B EDG AOT from 72 hours to 14 days.

4.5.1. Compensatory Measures

The following compensatory measures are included for the A&B EDG AOT extension:

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).

2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.

3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the same mechanical division (C or D, respectively) must be capable, operable and available to mitigate the consequence of a LOOP condition.

4. The removal from service of safety systems (e.g., HPCI or RCIC) and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.

5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.

6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

These compensatory measures are included as regulatory commitments in Attachment 5 to this submittal. They will also be included in the TS BASES Section 3.4.8.

4.5.2. Other Considerations

Attendant Shutdown Risk reductions associated with removing EDG PMs and overhauls from refueling outages have not been quantified as part of the Attachment 4 evaluation. The removal of the EDG PMs and overhauls from refueling outages is expected to further reduce the risk associated with the AOT extension.

In addition, the Configuration Risk Management Program (CRMP), discussed in Section 3.5, will ensure that the plant state is monitored to minimize the risk impact of the change.

4.5.3. Uncertainties

In addition to the assessment of the mean risk metrics which are specified in RG 1.177 and 1.174 for comparison with the acceptance guidelines, it is also prudent to examine whether modeling uncertainties may distort these comparisons.

Therefore, an extensive review of potential modeling uncertainties that may impact the risk metrics is performed. To this end, NUREG-1855 and the companion EPRI guidelines on the treatment of uncertainties were used. Section 5 and Appendices B and F of Attachment 4 provide various perspectives on the uncertainties.
Uncertainties are minimized by the use of the Compensatory Measures listed above.

4.5.4. Conclusion

As documented in Attachment 4, the risk change calculated with the Hope Creek PRA for the proposed EDG AOT extension for the A and B diesel generators is very small.

The quantitative results of the evaluation are shown in the table below:

RESULTS OF RISK EVALUATION FOR HOPE CREEK

Risk Metric	Risk Metric Results(1)	Risk Significance Guideline	Meets Acceptance Guideline
ΔCDF_{AVE} (/yr)	1.94E-07	< 1.0E-06	Yes(2)
$\Delta LERF_{AVE}$ (/yr)	1.81E-08	< 1.0E-07	Yes(2)
$ICCDP_{EDG\ A}$	9.96E-08	< 5.0E-07	Yes
$ICLERP_{EDG\ A}$	< 1.00E-10	< 5.0E-08	Yes
$ICCDP_{EDGB}$	2.72E-07	< 5.0E-07	Yes
$ICLERP_{EDGB}$	3.49E-08	< 5.0E-08	Yes

(1) Incorporate compensatory measures listed in Section 4.5.1.
(2) Region III of RG 1.174 -- very small risk changes.

In addition, the comparisons of the CDF and LERF risk metrics with the Reg. Guide 1.174 guidelines are provided in Attachment 4. These comparisons show that incremental risk is very low.

The ICCDP and ICLERP for each EDG are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Reg. Guide 1.177 for the increased EDG AOT have been met. Furthermore, the calculated changes in CDF and LERF due to the extension of the EDG A and B AOT, as mitigated by the compensating measures listed above, have been shown to meet the risk significance criteria of Reg. Guide 1.174 with substantial margin, i.e., Region III which represents "very small risk changes". These calculations support the increase in EDG AOT from a quantitative risk-informed perspective, consistent with application of the plant operational and maintenance practices discussed in this evaluation.

The conclusion of these evaluations is that the risk implications associated with the change in Diesel Generator AOT from 72 hours to 14 days represents a very small risk increment.

5.0 REGULATORY SAFETY ANALYSIS

This license amendment request proposes changes to the Hope Creek Generating Station (HCGS) Technical Specifications (TS) Specifically, TS 3/4.8.1, "AC Sources – Operating", ACTION b, concerning one inoperable Emergency Diesel Generator (EDG). The proposed change would extend the Allowed Outage Time (AOT) for the 'A' and 'B' EDGs from 72 hours to 14 days. The proposed new AOT is based on application of the HCGS Probability Risk Assessment (PRA) in support of a risk-informed extension, and on additional considerations and compensatory actions. The risk evaluation and deterministic engineering analysis supporting the proposed change was developed in accordance with the guidelines established in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed

Decision-making: Technical Specifications," and NRC Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."

5.1 No Significant Hazards Consideration

PSEG has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The emergency diesel generators are safety related components which provide backup electrical power supply to the onsite Safeguards Distribution System. The emergency diesel generators are not accident initiators; the EDGs are designed to mitigate the consequences of previously evaluated accidents including a loss of offsite power. Extending the AOT for a single EDG would not affect the previously evaluated accidents since the remaining EDGs supporting the redundant Engineered Safety Features (ESF) systems would continue to be available to perform the accident mitigation functions. Thus allowing an emergency diesel generator to be inoperable for an additional 11 days for performance of maintenance or testing does not increase the probability of a previously evaluated accident.

Deterministic and probabilistic risk assessments evaluated the effect of the proposed Technical Specification changes on the availability of an electrical power supply to the plant emergency safeguards features systems. These assessments concluded that the proposed Technical Specification changes do not involve a significant increase in the risk of power supply unavailability.

There is incremental risk associated with continued operation for an additional 11 days with one emergency diesel generator inoperable; however, the calculated impact on risk is very small and is consistent with the acceptance guidelines contained in Regulatory Guides 1.174 and 1.177. This risk is judged to be reasonably consistent with the risk associated with operations for 72 hours with one emergency diesel generator inoperable as allowed by the current Technical Specifications. Specifically, the remaining operable emergency diesel generators and paths are adequate to supply electrical power to the onsite Safeguards Distribution System. An emergency diesel generator is required to operate only if both offsite power sources fail and there is an event which requires operation of the plant emergency safeguards features such as a design basis accident. The probability of a design basis accident occurring during this period is low.

The consequences of previously evaluated accidents will remain the same during the proposed 14 day AOT as during the current 72 hour AOT. The ability of the remaining TS required EDG to mitigate the consequences of an accident will not be affected since no additional failures are postulated while equipment is inoperable within the TS AOT. The standby power supply for each of the four safety-related load groups consists of one EDG complete with its auxiliaries, which include the cooling water, starting air, lubrication, intake and exhaust, and fuel oil systems. The sizing of the EDGs and the loads assigned among them is such that any combination of three out of four of these EDGs is capable of shutting down the plant safely, maintaining the plant in a safe shutdown condition, and mitigating the consequences of accident conditions.

Thus this change does not involve a significant increase in the probability or consequences of a previously analyzed accident.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

The proposed Technical Specification changes do not involve a change in the plant design, system operation, or procedures involved with the emergency diesel generators. The proposed changes allow an emergency diesel generator to be inoperable for additional time. Equipment will be operated in the same configuration and manner that is currently allowed and designed for. There are no new failure modes or mechanisms created due to plant operation for an extended period to perform emergency diesel generator maintenance or testing. Extended operation with an inoperable emergency diesel generator does not involve any modification in the operational limits or physical design of plant systems. There are no new accident precursors generated due to the extended AOT.

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

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No

Currently, if an inoperable emergency diesel generator is not restored to operable status within 72 hours, Technical Specification 3.8.1.1 ACTION b requires the unit be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. The proposed Technical Specification changes will allow steady state plant operation at 100% power for an additional 11 days.

Deterministic and probabilistic risk assessments evaluated the effect of the proposed Technical Specification changes on the availability of an electrical power supply to the plant emergency safeguards features systems. These assessments concluded that the proposed Technical Specification changes do not involve a significant increase in the risk of power supply unavailability.

The EDGs continue to meet their design requirements; there is no reduction in capability or change in design configuration. The EDG response to LOOP, LOCA, SBO, or fire is not changed by this proposed amendment; there is no change to the EDG operating parameters. In the extended AOT, as in the existing AOT, the remaining operable emergency diesel generators and paths are adequate to supply electrical power to the onsite Safeguards Distribution System. The proposed change does not alter a design basis or safety limit; therefore it does not significantly reduce the margin of safety. The EDGs will continue to operate per the existing design and regulatory requirements.

Therefore, based on the considerations given above, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, PSEG concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

Section 50.63 of 10 CFR, "Loss of all alternating current power," requires that light-water-cooled nuclear power plants licensed to operate be able to withstand for a specified duration and recover from a station blackout.

Section 50.65 of 10 CFR, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities must not reduce the overall availability of the systems, structures and components. It also requires that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 states, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSC) that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

GDC-18, "Inspection and testing of electric power systems," states that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing of important areas and features, such as insulation and connections to assess the continuity of the systems and the condition of their components.

RG 1.155, "Station Blackout," describes a method acceptable to the NRC staff for complying with the Commission regulation that requires nuclear power plants to be capable of coping with a station blackout (SBO) event for a specified duration.

RG 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," provides guidance on methods acceptable to the NRC for assessing and managing the increase in risk that may result from maintenance activities and for implementing the optional reduction in scope of SSCs considered in the assessments.

RG 1.174, "An Approach for Using Probabilistic Risk Assessment [PRA] in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights. This RG also provides risk acceptance guidelines for evaluating the results of such assessments.

RG 1.177 identifies an acceptable risk-informed approach including additional guidance specifically geared toward the assessment of proposed TS AOT changes. Specifically, RG

1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed AOT TS change.

5.3 Precedent

The NRC has recently approved requests to extend the AOTs for Emergency Diesel Generators for Fermi 2 (ADAMS ML071830105), Prairie Island (ADAMS ML071310023), Palo Verde (ADAMS ML063350074), and Wolf Creek (ADAMS ML053490174).

5.4 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

PSEG has evaluated the proposed amendment for environmental considerations. The review has determined that the proposed amendment would change requirements with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, and would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases," dated November 2002

2. RG 1.177, "An Approach for Plant- Specific, Risk-Informed Decision making: Technical Specifications," dated August 1998 "

3. NUMARC 87-00, “Guidelines and Technical Bases for NUMARC Initiatives addressing Station Blackout at Light Water Reactors”

4. Regulatory Guide 1.200, An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk Informed Activities, Revision 1, January 2007

5. NRC Safety Goal Policy Statement, USNRC, “Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement,” Federal Register, Volume 60, p.42622, August 16, 1995.

TECHNICAL SPECIFICATION PAGES WITH PROPOSED CHANGES – LAR H10-03

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3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and
b. Four separate and independent diesel generators, each with:

    1. A separate fuel oil day tank containing a minimum of 360 gallons of fuel,
    2. A separate fuel storage system consisting of two storage tanks containing a minimum of 44,800 gallons of fuel, and
    3. A separate fuel transfer pump for each storage tank.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Note: LCO 3.0.4b is not applicable to DGs

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the inoperable offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours* unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated. If continued operation is permitted by LCO 3.7.1.3, restore the inoperable diesel generator to OPERABLE status ~~within 72 hours for diesel generators A or B, or~~ within 14 days ~~for diesel generators C or D~~, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

* This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

TECHNICAL SPECIFICATION BASES PAGES WITH PROPOSED CHANGES – LAR H10-03
(Provided for INFORMATION ONLY)

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least one of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. or D.C. source.

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources", December 1974 as modified by plant specific analysis and diesel generator manufacturer recommendations. When two diesel generators are inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generators as a source of emergency power, are also OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period two or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component. The 14 day AOT for the "C" and "D" EDGs is based upon the following conditions being met:

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM). In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.

2. The overall unavailability of the EDG should not exceed the performance criteria developed for implementation of 10CFR50.65 requirements as described in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants", as endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants", June 1993.

3. When the "C" or "D" EDG is removed from service for an extended 14 day AOT, any two of the remaining EDGs must be capable, operable and available to mitigate the consequences of a LOOP condition.

4. The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.

5. Entry into this LCO should not be abused by repeated voluntary entry into and exit from the LCO. The primary intent of the extended EDG AOT is that the extended EDG AOT from 72 hours to 14 days may be needed to perform preplanned EDG maintenance such as teardowns and modifications that would otherwise extend beyond the original 72 hour AOT.

6. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.

7. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

The 14 day AOT for the "A" and "B" EDGs is based upon the following conditions being met:

1. ***Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).***

2. ***In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.***

3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the same mechanical division (C or D, respectively) must be capable, operable and available to mitigate the consequence of a LOOP condition.

4. The removal from service of safety systems *(e.g., HPCI or RCIC) and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.*

5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.

6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

TECHNICAL EVALUATION OF EXTENDING HOPE CREEK DIESEL GENERATOR ALLOWED OUTAGE TIME (AOT) USING PROBABILISTIC RISK ASSESSMENT MODELS FOR HOPE CREEK

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TECHNICAL EVALUATION OF EXTENDING HOPE CREEK DIESEL GENERATOR ALLOWED OUTAGE TIME (AOT) USING PROBABILISTIC RISK ASSESSMENT MODELS FOR HOPE CREEK

Prepared by: E T Burns / Josh Strode Date: 3/17/2010

Reviewed by: Lawrence Lee Date: 3/17/2010

Approved by: E T Burns Date: 3-17-2010

Revisions:

Rev.	Description	Preparer/Date	Reviewer/Date	Approver/Date

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Executive Summary

TECHNICAL EVALUATION OF EXTENDING HOPE CREEK DIESEL GENERATOR ALLOWED OUTAGE TIME (AOT) USING PROBABILISTIC RISK ASSESSMENT MODELS FOR HOPE CREEK

Purpose

Consistent with the NRC's approach to risk-informed regulation, PSEG has identified a particular Technical Specification requirement that is restrictive in its nature and, if relaxed, has a minimal impact on the safety of the plant. This Technical Specification is the requirement for the Emergency Diesel Generator (EDG) Allowed Outage Time (AOT) to be restricted to 72 hours for the A and B Emergency Diesel Generators (EDGs). The proposed change is to increase the Diesel Generator AOT, or as sometimes called the Complete Time (CT), from the currently specified 72 hours to 14 days(1).

RISK INFORMED REGULATORY ENVIRONMENT

Since the mid-1980s, the NRC has been reviewing and granting improvements to TS that are based, at least in part, on probabilistic risk assessment (PRA) insights. In its final policy statement on TS improvements of July 22, 1993, the NRC stated that it . . .

> *. . . expects that licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific PRA [probabilistic safety assessment] or risk survey and any available literature on risk insights and PRAs. . . . Similarly, the NRC staff will also employ risk insights and PRAs in evaluating Technical Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements.*

(1) The NRC has previously issued an SER to allow the Hope Creek C and D EDGs to extend their AOT from 72 hours to 14 days.

The NRC has specified in Regulatory Guides the risk metrics that should be calculated to provide input into the decision making process. The risk metrics chosen by the NRC in their Regulatory Guides include the following:

- The change in Core Damage Frequency (CDF) (Reg. Guide 1.174)
- The change in Large Early Release Frequency (LERF) (Reg. Guide 1.174)
- The Incremental Conditional Core Damage Probability (ICCDP) (Reg. Guide 1.177)
- The Incremental Conditional Large Early Release Probability (ICLERP) (Reg. Guide 1.177)

These risk metrics are all calculated with the Hope Creek PRA EDG AOT Extension Application model which includes:

- Internal and External hazards
- Peer Review comments that affect the EDG AOT application
- Anticipated plant change to remove the Salem 3 Gas Turbine
- All diesel and proceduralized electrical cross ties accounted for in the model.

Quantitative guidelines are defined by the NRC in RG 1.174 and 1.177 for what is an acceptably small change in risk.(1) (2)

- The Hope Creek calculated ICCDP and ICLERP for each EDG are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Reg. Guide 1.177 for the increased EDG Allowed Outage Time have been met.

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(1) The guidelines given in Regulatory Guide 1.177 include:

> The licensee has demonstrated that the TS AOT change has only a small quantitative impact on plant risk. An ICCDP of less than 5.0E-7 is considered small for a single TS AOT change. An ICLERP of 5.0E-8 or less is also considered small.

(2) The guidelines from Regulatory Guide 1.174 are provided to assure that the CDF and LERF changes when the extended AOT is implemented remain acceptable. These guidelines specify acceptably small changes as a function of the absolute values of the CDF and LERF.

- Furthermore, the evaluation of changes in CDF and LERF due to the expected increased EDG unavailability, as mitigated by the compensatory measures listed in Section 3, have been shown to meet the risk significance criteria of Regulatory Guide 1.174 with substantial margin.

These calculations support the increase in EDG Allowed Outage Time (AOT) from a quantitative risk-informed perspective.

QUANTITATIVE RESULTS

The quantitative results of the evaluation are shown in the table below:

RESULTS OF RISK EVALUATION FOR HOPE CREEK

Risk Metric	Risk Metric Results[1]	Risk Significance Guideline	Meets Acceptance Guideline
ΔCDF_{AVE} (/yr)	1.94E-07	< 1.0E-06	Yes[2]
$\Delta LERF_{AVE}$ (/yr)	1.81E-08	< 1.0E-07	Yes[2]
$ICCDP_{EDG\ A}$	9.96E-08	< 5.0E-07	Yes
$ICLERP_{EDG\ A}$	< 1.00E-10	< 5.0E-08	Yes
$ICCDP_{EDGB}$	2.72E-07	< 5.0E-07	Yes
$ICLERP_{EDGB}$	3.49E-08	< 5.0E-08	Yes

(1) Incorporate compensatory measures listed in Section 3.3.
(2) Region III of RG 1.174 -- very small risk changes.

In addition, the comparisons of the CDF and LERF risk metrics with the Reg. Guide 1.174 guidelines are shown in Figures 1 and 2, respectively. These comparisons show that the incremental risk is very low.

OTHER CONSIDERATIONS

Attendant Shutdown Risk reductions associated with removing EDG Preventive Maintenance (PM) from refueling outages have not been quantified as part of this evaluation. The removal of EDG PMs from refuel outages is expected to further reduce the incremental risk associated with extending the AOT for EDG A and B.

In addition, a Configuration Risk Management Program (CRMP) will ensure that the plant state is monitored to minimize the risk impact of the change.

UNCERTAINTIES

In addition to the assessment of the mean risk metrics which are specified in RG 1.177 and 1.174 for comparison with the acceptance guidelines, it is also prudent to examine whether modeling uncertainties may distort these comparisons.

Therefore, an extensive review of potential modeling uncertainties that may impact the risk metrics is performed. To this end, NUREG-1855 and the companion EPRI guidelines on the treatment of uncertainties are used. Section 5 and Appendices B and F provide various perspectives on the identification and disposition of various uncertainties. Section 5 provides a summary for input to the decision makers.

Uncertainties are minimized by the use of the Compensatory Measures.

CONCLUSION

The risk change calculated with the Hope Creek PRA for the proposed EDG AOT extension for the A and B diesel generators is very small.

The ICCDP and ICLERP for each EDG, as mitigated by the compensatory measures listed in Section 3.3, are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Reg. Guide 1.177 for the increased EDG Allowed Outage Time have been met.

Furthermore, the calculation of changes in CDF and LERF due to the extended EDG A and B AOT, as mitigated by the compensatory measures listed in Section 3, have been shown to meet the risk significance criteria of Regulatory Guide 1.174 with substantial margin, i.e., Region III which represents "very small risk changes".

These calculations support the increase in EDG Allowed Outage Time from a quantitative risk-informed perspective so long as the plant operational and maintenance practices are in reasonable agreement with the assumptions made in this evaluation.

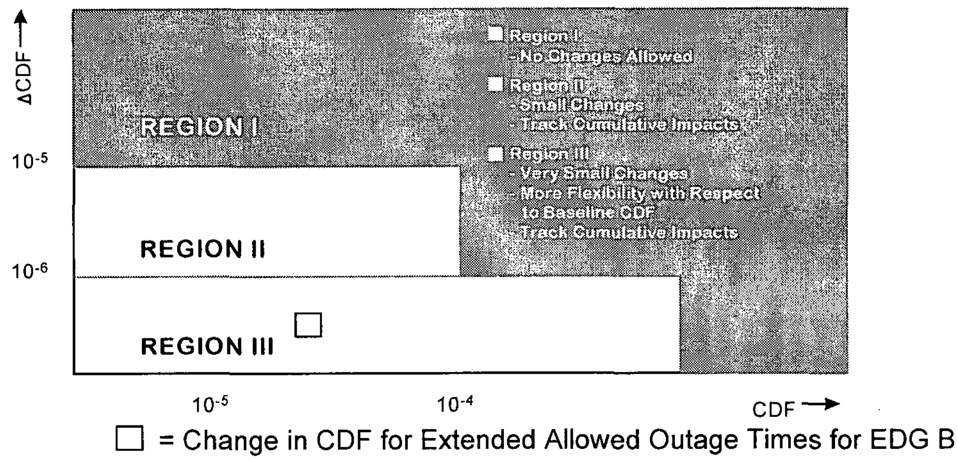
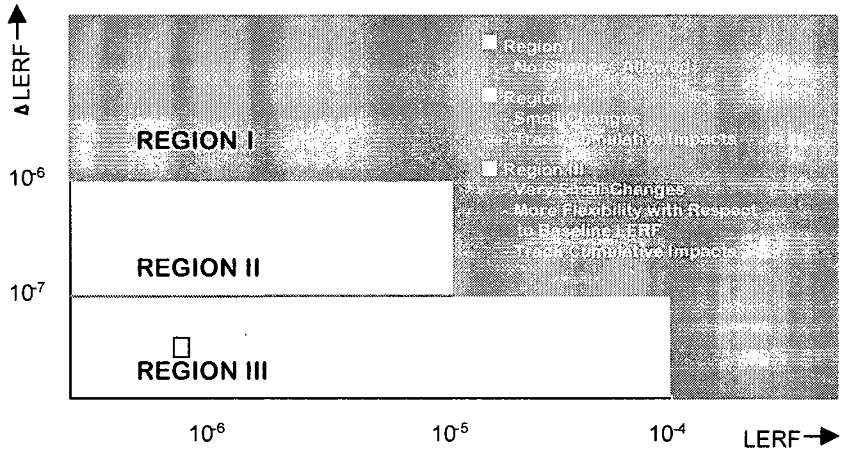


Figure 1 Acceptance Guidelines* for Core Damage Frequency (CDF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.



☐ Change in LERF For Extended AOT for EDG B

Figure 2 Acceptance Guidelines* for Large Early Release Frequency (LERF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision-making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

Section 1
INTRODUCTION

1.1 PURPOSE

Consistent with the NRC's approach to risk-informed regulation, PSEG has identified a particular Technical Specification requirement that is restrictive in its nature and, if relaxed, has a minimal impact on the safety of the plant. This Technical Specification is the requirement for the Emergency Diesel Generator (EDG) Allowed Outage Time (AOT) to be restricted to 72 hours for the A and B EDGs.[(1)] The proposed change is to increase the Diesel Generator Completion Time, or as sometimes called the Allowed Outage Time (AOT), from the currently specified 72 hours[(1)] to 14 days.

The proposed changes to Technical Specifications will extend the allowable Allowed Outage Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG). The changes are being proposed to support on-line maintenance and overhaul of the EDGs. The current Allowed Outage Time for restoration of an inoperable EDG (72 hours)[(1)] is insufficient to support the required diesel generator maintenance and post-maintenance testing windows while the Hope Creek unit is at power.

<u>Benefits</u>

Implementation of this proposed Allowed Outage Time extension will provide the following benefits:

- Allow increased flexibility in the scheduling and performance of preventive maintenance.
- Improve diesel generator reliability
- Allow better control and allocation of resources. Allowing on-line preventive maintenance, including overhauls, provides the flexibility to

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(1) It is noted that the NRC in Amendment 74 to Facility Operating License No. NPR-57 dated August 1, 1995 approved the change in the Technical Specification AOT for the C and D EDGs from 72 hours to 14 days.

focus more quality resources on any required or elective EDG maintenance.

- Avert unplanned plant shutdowns. Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve EDG availability during shutdown Modes or Conditions. This will reduce the shutdown risk associated with EDG maintenance and the synergistic effects on risk due to EDG unavailability occurring at the same time as various other activities and equipment outages that occur during a refueling outage.
- Permit scheduling of EDG overhauls within the requested 14 day period.
- Ensure consistency of treatment of all four EDGs to reduce misinterpretations.

This can be understood by considering the following:

- Five (5) year diesel overhaul, and other types of regularly scheduled preventive maintenance (PM), cannot be completed within 72 hours.
- To ensure continued high reliability, the ability to schedule the overhaul and regularly scheduled PM on-line is critical. (Scheduling EDG overhauls during the complex periods of a refuel outage can lead to delays in scheduling.)
- Performing the overhaul on-line allows the focus of the maintenance organization and site management on this critical task without the additional scheduling challenges of the refuel activities.

The proposed Allowed Outage Time of 14 days is adequate to perform EDG maintenance. This time period has also been determined to be sufficient to perform normal preventive EDG inspections and maintenance requiring disassembly of the EDG and to perform required post-maintenance and operability tests required to return the EDG to operable status.

1.2 BACKGROUND

Since the mid-1980s, the NRC has been reviewing and granting improvements to TS that are based, at least in part, on probabilistic risk assessment (PRA) insights. In its final policy statement on TS improvements of July 22, 1993, the NRC stated that it . . .

> *. . . expects that licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific PRA [probabilistic safety assessment][(1)] or risk survey and any available literature on risk insights and PRAs. . . . Similarly, the NRC staff will also employ risk insights and PRAs in evaluating Technical Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements.*

The NRC reiterated this point when it issued the revision to 10 CFR 50.36, "Technical Specifications," in July 1995. In August 1995, the NRC adopted a final policy statement on the use of PRA methods in nuclear regulatory activities that encouraged greater use of PRA to improve safety decision making and regulatory efficiency. The PRA policy statement included the following points:

1. The use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.
2. PRA and associated analyses (e.g., sensitivity studies, uncertainty analyses, and importance measures) should be used in regulatory matters, where practical within the bounds of the state of the art, to reduce unnecessary conservatism associated with current regulatory requirements.
3. PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available for review.

(1) PSA and PRA are used interchangeably herein.

Plants with similar system configurations have increased the AOTs on EDGs using a combination of deterministic evaluations, configuration control, and probabilistic assessments. These plants include Hope Creek Generating Station[(1)] [6], Perry Nuclear Power Plant [4], Pilgrim [8], South Texas Project [5], Columbia Generating Station [24], and LaSalle [25].

The movement of the NRC to more risk-informed regulation has led to the NRC identifying Regulatory Guides and associated processes by which licensees can submit changes to the plant design basis including Technical Specifications. As examples, Regulatory Guides 1.174 [2] and 1.177 [3], both provide mechanisms to demonstrate valuable PRA input for Technical Specification modification.

1.3 TECHNICAL SPECIFICATIONS

The Hope Creek Technical Specifications used in the probabilistic analysis are modeled based on the current Technical Specifications.

As with all Technical Specifications, there is no rule to limit the number of times per year that an extended AOT would be involved. However, there are a number of programs (e.g., MSPI, Maintenance Rule) that are monitoring programs that strongly discourage extended outages of key equipment such as diesel generators. In addition, there is no reason to believe that this extended AOT would be abused. Examples include the historical evidence with the C and D EDGs which already have the extended AOT approved in the Technical Specifications.

PSEG in a letter to the NRC, LR-N97167, dated March 21, 1997 clarified the site procedures and practices that would be implemented to support the NRC approved extended AOT on the C and D EDGs. The equivalent site procedures and practices are to be implemented for the A and B EDG extended AOTs if approved by the NRC.

(1) EDGs C and D.

1.4 REGULATORY GUIDES

The license amendment request for an extension in the EDG Allowed Outage Time (AOT) is made consistent with the NRC risk-informed process.

The internal events PRA is developed and peer reviewed consistent with the ASME PRA Standard as endorsed by Regulatory Guide (RG) 1.200 (Rev. 1) [10].

The risk-informed application is developed consistent with the general guidance in RG 1.174 and the specific guidance for changes in AOTs contained in RG 1.177.

1.4.1 Acceptance Guidelines -- R.G. 1.174

R.G. 1.174 specifies the acceptance guidelines in terms of the change in CDF and LERF as a function of the base model CDF and LERF, respectively.

Figure 1.4-1 identifies the acceptance guidelines for R.G. 1.174 for the ΔCDF risk metric.

Figure 1.4-2 identifies the acceptance guidelines for R.G. 1.174 for the ΔLERF risk metric.

Further, R.G. 1.174 in Section 2.2.5.5 [2] identifies the following regarding the PRA calculation to be used in comparison with the acceptance guidelines:

> Because of the way the acceptance guidelines were developed, the appropriate numerical measures to use in the initial comparison of the PRA results to the acceptance guidelines are mean values.

1.4.2 Acceptance Guidelines -- R.G. 1.177

Regulatory Guide 1.177 specifies acceptance guidelines in terms of two parameters that have been developed by the NRC as follows:

ICCDP - Incremental Conditional Core Damage Probability

[(conditional CDF with the subject equipment out of service) - (baseline CDF with nominal expected equipment unavailabilities)] x duration of single AOT(1) under consideration)

ICLERP - Incremental Conditional Large Early Release Probability

[(conditional LERF with the subject equipment out of service) - (baseline LERF with nominal expected equipment unavailabilities)] x (duration of single AOT(1) under consideration)

Further, the NRC has developed acceptance guidelines which the NRC states "should not be interpreted as overly prescriptive".

Risk Metric Parameter	Acceptance Guideline
ICCDP	5.0E-07
ICLERP	5.0E-08

1.5 SCOPE

This analysis is to address the adequacy of the proposed extension of A and B Emergency Diesel Generator (EDG) Allowed Outage Times (AOT) from the current 72 hours to 14 days using the Hope Creek Probabilistic Risk Assessment (PRA) model.

The following scope of the at-power PRA models is included:

- <u>Internal Events</u>: Model developed in accordance with the ASME/ANS PRA Standard and Peer Reviewed
- <u>Internal Floods</u>: Model developed in accordance with the ASME/ANS PRA Standard and Peer Reviewed
- <u>Seismic Events</u>: Model based on Seismic Evaluation from IPEEE included in the model quantification

(1) Currently referred to as Completion Time (CT)

- Internal Fires: Model based on Fire Evaluation from IPEEE included in the model quantification
- Other External Event Hazards: Non-contributors based on an independent review of IPEEE results which quantitatively or qualitatively screened these from further analysis.

The NRC has specified in Regulatory Guides the risk measures that should be calculated to provide input into the decision making process. The risk measures chosen by the NRC in their Regulatory Guides include the following:

- The change in Core Damage Frequency (CDF) (Reg. Guide 1.174)
- The change in Large Early Release Frequency (LERF) (Reg. Guide 1.174)
- The Incremental Conditional Core Damage Probability (ICCDP) (Reg. Guide 1.177)
- The Incremental Conditional Large Early Release Probability (ICLERP) (Reg. Guide 1.177)

These values are all calculated with the latest Hope Creek at-power PRA model including internal and external events and that also includes all diesels and proceduralized electrical cross ties credited in the model.

The risk associated with plant shutdown (outages) is expected to decrease as a result of the change in at-power Allowed Outage Times for the EDGs. The requested Technical Specification change will allow moving the EDG work window from the outage to an at-power work week. This will reduce the outage risk. This reduction is discussed in Section 3.2.

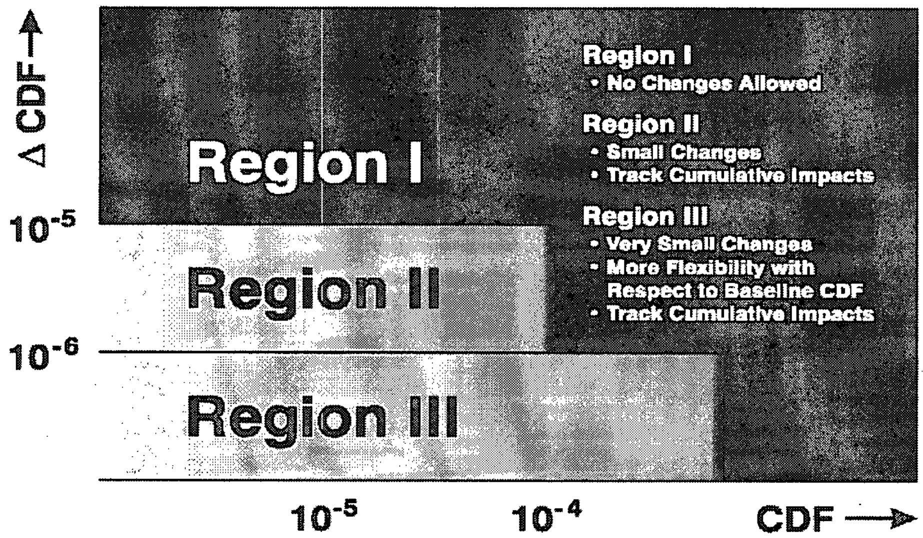


Figure 1.4-1 Acceptance Guidelines* for Core Damage Frequency (CDF)

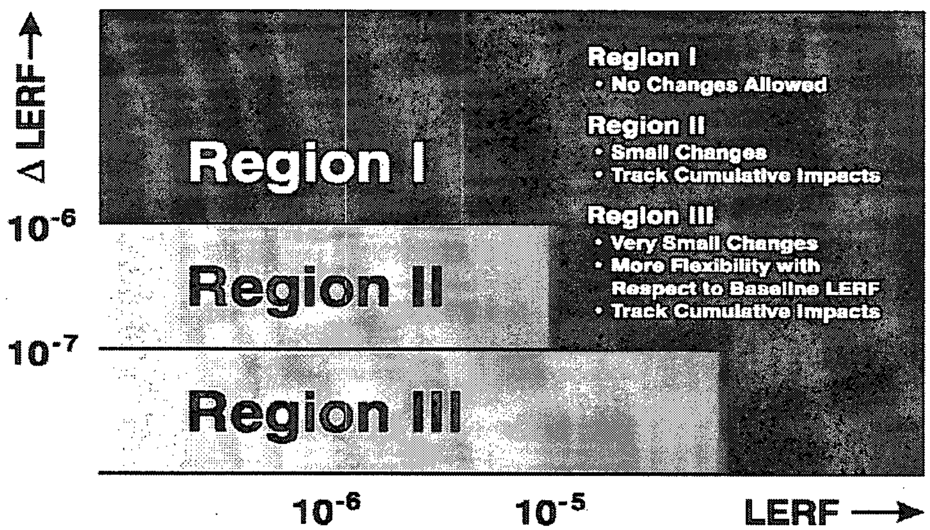


Figure 1.4-2 Acceptance Guidelines* for Large Early Release Frequency (LERF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decisionmaking, the boundaries between the regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

1.6 HOPE CREEK PRA MODEL AND ITS ATTRIBUTES

The Hope Creek Generating Station (HCGS) PRA internal events at-power model and documentation has been maintained current with the as-built, as-operated plant and is routinely updated to reflect the current plant configuration and to reflect the accumulation of additional plant operating history and component failure data. The Level 1 and Level 2 HCGS PRA analyses were originally developed and submitted to the NRC as the Hope Creek Generating Station Individual Plant Examination (IPE) Submittal [7] in response to NRC Generic Letter 88-20. [26] The HCGS PRA has been updated many times since the original IPE. A summary of the HCGS PRA history is provided in Table 1-1.

1.6.1 IPE

The IPE submittal presented a summary of the updated Level 1 and Level 2 PRA analyses, along with a description of the review process, a description of insights learned through the IPE process, as well as PSEG management plans for the future use of the HCGS PRAs, and the insights gained through the IPE process.

1.6.2 Peer Review

During 1999, PSEG participated in a PRA Peer Review Certification of the Hope Creek PRA administered under the auspices of the BWROG Peer Certification Committee. [14] The purpose of the PRA peer review process is to establish a method of assessing the technical quality of the PRA for the spectrum of its potential applications.

1.6.3 2000 Update

PSEG comprehensively revised the PSA models in 2000 using the NUPRA software.

1.6.4 Conversion to CAFTA & Incorporation of EPU

For the 2003A model update, the CAFTA software suite was selected. The conversion of the HCGS NUPRA PRA model to CAFTA was completed in November 2002. This straight conversion involved no model or data changes.

The CAFTA single top and the NUPRA models produced essentially the same CDF for the modeling assumptions, scope, and data used for that analysis.

This converted CAFTA model was then used as the starting point for the 2003A model update. Substantial changes were then incorporated into the model to account for the following:

- Completely new HRA using the EPRI HRA Calculator
- Revised accident sequence definitions (Event Trees)
- New MAAP calculations to support the success criteria and accident sequence timing at the Extended Power Uprate (EPU) configuration
- Updated data (initiating events, component failure data, and unavailability data)
- Modified system models
- Updated common cause failures incorporating the latest NRC data
- The addition of internal flood accident sequences
- EPU power level and associated MAAP 4.0.6 calculations to support timing and success criteria changes

1.6.5 EPU Modification

The Hope Creek 2005C PRA Quantification Notebook (HC05C) documents an unscheduled update to the 2003A PRA model to support the EPU LAR. The 2005C PRA model was created to address the following items:

- Remove conservatism in SACS-SW success criteria
- Include more detailed logic for AC power supplies
- Assess the operator action HEPs to support the EPU submittal

Table 1-1

HISTORY OF HOPE CREEK NUCLEAR STATION PRA MODEL UPDATES

Model Name	Description	Internal Events CDF (/yr)	Truncation (/yr)	Date
IPE	Original IPE Submittal (1994)	4.6E-5[(1)]	Not Reported	April 1994
2000	NUPRA Model	8.89E-06	1E-10	Dec. 2000
2003A	Full PRA upgrade including Peer Review comments, ASME PSA STD Gaps and conversion of model from NUPRA to CAFTA	3.14E-5	5E-11	August 2003
Rev. 2.0A	Includes PSEG modifications on 480 VAC dependencies, SACS, success criteria, and SACS-SW HEPs. (Also referred to as the "On the Spot Model" change.)	2.78E-5	5E-11	October 2005
2005A	Interim PRA model to address conservatism in Rev. 2.0A model.	See 2005B	See 2005B	October 2005
2005B	PRA model used as input for the EPU submittal. This model removes conservatism introduced in the Rev. 2.0A model (e.g., SACS heat load manipulation HEPs)	1.01E-5	5E-11	November 2005
2005C	Modify 2005B EPU model to support online maintenance evaluations and MSPI calculations.[(2)]	9.76E-6	5E-11	February 2006
HC108A	Add plant modifications, update HRA, update internal flood, update data	7.60E-6	5E-11	August 2008
HC108B	Procedural change to SACS/SSW operation and minor basic event changes resulting from PRA Peer Review process.	5.11E-6	1E-12	November 2008

(1) PSEG modified the success criteria for SACS/SSW and calculated a revised value of 1.3E-05/yr.

(2) The only PRA model change from the 2005B EPU PRA model to the 2005C Base PRA model is to reduce the Turbine Trip initiating event frequency from 1.25/yr to 1.03/yr to reflect plant specific operating history.

1.6.6 2008 Update

The 2008 PRA Update was performed to satisfy the PSEG internal requirement for a periodic PRA Update and to address open issues such as the PRA self-assessment "gaps", additional UREs, and updated data.

This periodic update includes:

- A complete update of the initiating events
- A complete revision to the HRA including simulator observations and crew interviews
- Significant modeling changes to address the following:
  - Incorporation of plant changes
  - Incorporation of procedure changes
  - Resolution of discrepancies noted in the self assessment
  - Add plant modifications (e.g., portable power supply, RCIC back pressure trip)
- A complete update of the data analysis involving common cause

The HCGS 2008 PRA model (HC108B) is the result of upgrading the Hope Creek Internal Events PRA model. A summary of the changes to the Hope Creek PRA model is included here. The details associated with items can be found in the associated modular PRA document that treats the individual topic. The Hope Creek PRA Roadmap Document identifies the available modular documentation that supports the Hope Creek PRA. Major changes incorporated into the model include the following data, plant, procedure, and analysis changes:

Model Framework

- The CAFTA model framework originally developed for the 2003A model upgrade is retained for the HC108B model.
- The LERF model has been expanded to a full Level 2 with a full spectrum of radionuclide releases, including LERF.

- A single top fault tree model has been created to quantify the Level 1 CDF.[1]
- A separate single top fault tree model has been created to quantify the Level 2 LERF[1].

The HCGS PRA Update process includes an evaluation of the 2008 PRA model, data, and documentation using the ASME PRA Standard as endorsed by RG 1.200 (Rev. 1). The HCGS Roadmap Document Appendix B provides the reference sections of the HCGS documentation that supports the individual Supporting Requirements.

The Roadmap Document provides the link between the ASME PRA Standard Supporting Requirement and the HCGS PRA. The self-assessment developers then use their assessment of the PRA and its documentation to cite a Capability Category.

Initiating Events

- Bayesian updated initiating event frequencies utilizing the most recent Hope Creek operating experience and latest generic BWR operating experience.
- Allocation of LOCA frequencies on a location and size specific basis (i.e., the LOCA locations have been subdivided for more accurate assessments of their consequences.)
- Revised LOOP analysis is performed for initiating event frequencies and non-recovery probabilities including the impact of the 2003 Northeast Blackout using the latest INEEL analysis in NUREG/CR-6890 and accounting for local Hope Creek grid operating experience.
- The conditional probability of a LOOP given a transient or LOCA signal event is incorporated into the PRA modeling.

(1) Individual Level 1 CDF and Level 2 LERF sequences can also be quantified, if necessary.

Component Data

- Individual component random failure probabilities Bayesian are updated (as applicable) based upon the most recent plant specific data and the generic sources. This included revised component failure data including extensive use of plant-specific component failure data gathered from the Hope Creek Maintenance Rule program. Generic information from NUREG/CR-6928 and NUREG/CR-1715 are used when available as the prior distribution to support Bayesian updating.
- Common cause failure (CCF) calculations are revised to incorporate the upgraded individual random basic event probabilities and the most up to date Multiple Greek Letter (MGL) parameters from NUREG/CR-5497 and NUREG/CR-5485 available in 2007.
- Maintenance unavailability data is based on the most recent Hope Creek operating experience up to the freeze date.

HRA

- Extensive HRA re-assessment is performed utilizing the EPRI HRA Calculator 4.0 based on operating crew interviews using the latest EOPs and support procedures. Significant input from simulator observations is also included to supplement the crew talk-through of procedures.
- Significant effort to examine dependencies among HEPs is included.
- Expansion of HRA pre-initiating events is included in the model.
- Model HC108B also includes a significant procedural revision to the SSW/SACS operation implemented in October 2008.

Thermal Hydraulic Modeling

- MAAP 4.0.6 deterministic calculations are used to support the success criteria and HRA calculations (i.e., operator cues and time available for actions).
- Recirculation pump seal leakage failure modes are added to applicable scenarios.

System Models

- The analysis of FPS to support RPV makeup success has been added to the model.
- CST support of condensate injection is adequate when the makeup volume and flow rate requirements are small.
- Service water cross connect as an alternate water injection source to the RPV is included in the model.
- Extended DC battery life for cases with use of Portable Power supply has been assessed by PSEG and determined appropriate as a realistic approach to coping with an SBO.
- Shorter DC battery life for cases without successful DC charging from the Portable Power supply has been included in SBO accident sequence evaluations.

Accident Sequence Changes

- The accident sequence event trees were modified using the results of the latest MAAP calculations to assess success criteria.
- Addition of sequence specific success criteria for certain systems (e.g., CRD, HPCI, RCIC).

Internal Flood

- Internal Flood accident sequence evaluation has been developed and quantified consistent with the ASME PRA Standard and has been integrated into the full power internal events model. Pipe failure data from EPRI evaluation of operating experience is the bases for the pipe failure probabilities. (See Section 1.3 for additional discussion.)

Level 2

- The full spectrum of radionuclide release categories is included in the PRA model for Level 2. This will support SAMA evaluations as part of life extension initiatives.

1.6.7 IPEEE

The IPEEE evaluation is used as the basis for the fire and seismic models which are incorporated into the at-power internal events model to create the EDG AOT Extension Application Model. Therefore, the application model can yield a calculation of the "total" CDF and LERF[(1)].

It is recognized that the seismic and fire PRAs do not meet Capability Category II of the latest ASME/ANS PRA Standard. Nevertheless, it is judged that these hazard analyses are adequate to provide the input to this particular application. This conclusion is based on the relatively small contribution of the seismic and fire PRAs to the assessment of the risk metrics for the extended AOT for EDG A and B. This small contribution is explained in Appendix A for both the seismic and fire analyses.

It is also noted that the IPEEE was reviewed by the NRC [20], but not using the ANS Seismic or Fire PRA Standards. The reviews of the seismic and fire PRAs are judged to be supportive of their use in this PRA application.

The fire and seismic models used in the EDG AOT risk assessment incorporate all of the modeling enhancements (e.g., plant and procedure changes) applicable to the internal events model.

1.6.8 PRA Model Used for EDG AOT Extension Evaluation

The PRA model used for the EDG AOT extension evaluation combines the internal events and internal flood PRA that has been developed consistent with the ASME PRA Standard [11] and endorsed by RG 1.200 (Rev. 1) [10] with the external events analysis developed as part of the IPEEE to provide a quantitative model that allows the quantitative characterization of the risk metrics for comparison with RG 1.174 and RG 1.177. This is referred to as the EDG AOT Extension Application Model.

(1) Caution is required in adding the contributors from different hazards due to the potential biases that may exist in the individual hazard evaluations.

Section 2

ANALYSIS ROADMAP AND REPORT ORGANIZATION

The method of compliance to demonstrate the technical adequacy of the PRA used to support the EDG AOT Extension is provided in RG 1.200, Revision 1. The guidance in RG 1.200, Revision 1 indicates that the following steps should be followed to perform this study of the technical adequacy of the PRA:

1. Per Section 3.1 of RG 1.200, identify the parts of the PRA used to support the application
    - Describe the SSCs, operator actions, and operational characteristics affected by the application and how these are implemented in the PRA model.
    - Provide a definition of the acceptance guidelines used for the application.
2. Per Section 3.2 of RG 1.200, identify the scope of risk contributors addressed by the PRA model
    - If not full scope (i.e., internal and external), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.
3. Per Section 3.3 and 4.2 of RG 1.200, demonstrate the Technical Adequacy of the PRA
    - Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.
    - Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the Regulatory Guide (currently, in RG 1.200, Revision 1 this is just the internal events PRA standard). Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.
    - Document peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.

- Identify key assumptions and approximations relevant to the results used in the decision making process.

4. Per Section 4.2 of RG 1.200, summarize the risk assessment methodology used to assess the risk of the application
    - Include how the PRA model was modified to appropriately model the risk impact of the change request.

Table 2-1 summarizes the RG 1.200 identified actions and the corresponding location of that analysis or information in this report.

Table 2-1

RG 1.200 ANALYSIS ACTIONS ROADMAP TO DEMONSTRATE PRA TECHNICAL ADEQUACY

RG 1.200 Actions	Report Section
1. Identify the parts of the PRA used to support the application	Section 1.5 and Section 3
1a. Describe the SSCs, operator actions, and operational characteristics affected by the application and how these are implemented in the PRA model.	Section 1.1, 1.3, and Section 3
1b. Provide a definition of the acceptance guidelines used for the application.	Section 1.4
2. Identify the scope of risk contributors addressed by the PRA model. If not full scope (i.e., internal and external events), identify appropriate compensatory measures or provide bounding arguments to address the risk contributors not addressed by the model.	Section 1.5, Appendix A
3. Demonstrate the Technical Adequacy of the PRA.	Section 4 and Appendix A
3a. Identify plant changes (design or operational practices) that have been incorporated at the site, but are not yet in the PRA model and justify why the change does not impact the PRA results used to support the application.	Section 4.1.1, 4.1.2
3b. Document that the parts of the PRA used in the decision are consistent with applicable standards endorsed by the RG (currently, in RG 1.200 Rev. 1. RG 1.200 Rev. 1 addresses the internal events ASME PRA Standard). Provide justification to show that where specific requirements in the standard are not met, it will not unduly impact the results.	Section 4.1.3
3c. Document PRA peer review findings and observations that are applicable to the parts of the PRA required for the application, and for those that have not yet been addressed justify why the significant contributors would not be impacted.	Section 4.1.3, Table 4.1-1
3d. Identify key assumptions and approximations relevant to the results used in the decision making process.	Section 3.2, Appendix A, and Appendix B
4. Summarize the risk assessment methodology used to assess the risk of the application. Include how the PRA model was modified to appropriately model the risk impact of the change request.	Section 3

Section 3
TIER 1 RISK ASSESSMENT

The justification for the use of an EDG extended Allowed Outage Time is based upon risk-informed and deterministic evaluations consisting of three main elements:

1. Tier 1: Assessment of the impact of the proposed TS change using a valid and appropriate PRA model and compare with appropriate acceptance guidelines.

2. Tier 2: Evaluate equipment relative to the contribution to risk while the EDG is in the extended AOT.

   Examination of out of service combinations can be evaluated for their risk significance to determine if additional measures may be required.

3. Tier 3: Implementation of the Configuration Risk Management Program (CRMP) while an EDG is in an extended Allowed Outage Time. The CRMP is used for all work and helps ensure that there is no significant increase in the risk due to a severe accident while any EDG maintenance is performed. These elements provide adequate justification for approval of the requested Technical Specification change by providing a high degree of assurance that power can be provided to the ESF buses during the EDG extended Allowed Outage Time for all Design Basis Accidents (DBAs) (i.e., Loss of Offsite Power, Loss of Coolant Accident (LOCA)), Station Black-out (SBO), and 10 CFR 50 Appendix R fire during the EDG extended Allowed Outage Time.

This section addresses the risk assessment for the proposed extension of the EDG A and B Allowed Outage Time (AOT).

Appendix D also provides insights into the system configurations that could increase risk (Tier 2).

Beyond that, Hope Creek shall continue to minimize the time periods to complete any planned or unplanned maintenance. Plant configuration changes for planned and unplanned maintenance of the EDGs as well as the maintenance of equipment having risk significance is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the risk of a severe accident.

3.1 TIER 1 EVALUATION APPROACH

Hope Creek intends to use the 14-day Emergency Diesel Generator AOT primarily for performing vendor prescribed preventive maintenance at a frequency of no more than once per EDG per 24 months.

The proposed changes associated with the extended EDG AOT are evaluated using a Hope Creek PRA model to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increase in core damage frequency (CDF) and large early release frequency (LERF) is small and consistent with the NRC Safety Goal Policy Statement, USNRC, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995.

The modeling approach is consistent with the NRC guidance for the calculation of the requested risk measures using the Hope Creek PRA for internal events, internal floods, fire hazards, and seismic sequences:

- The models required for this evaluation are primarily related to the Loss of Offsite AC power, the associated accident sequences, the success criteria, the operator actions, common cause terms, and the data to characterize these. In addition, the Level 2 LERF model, the fire and seismic LOOP initiators are also part of the PRA model critical to the assessment of the EDG AOT extension application.
- Regulatory Guide 1.177 is followed to calculate the change in risk measures:
  - ICCDP
  - ICLERP

These conditional probabilities are performed to calculate the risk change during the proposed diesel generator extend AOT.

These are calculated for each diesel generator.

- An integrated assessment of the impact of the AOT extension is calculated assigning the "worst case" diesel unavailability to both the A and B diesel generators over a preventive maintenance (PM) cycle. This calculation can then be used to calculate the change in CDF and LERF in comparison with the criteria set in Reg. Guide 1.174.

  Regulatory Guide 1.174 has acceptance guidelines which are described in SECY 99-246 as "trigger points" at which questions are raised as to whether the proposed change provides reasonable assurance of adequate protection.

- Following the update of the PRA model and in preparation for the AOT submittal, PSEG performed an extensive review of the PRA model, particularly those sequences that could be adversely impacted by diesel generator unavailability (e.g., LOOP initiated sequences). In addition, external events with the possibility of affecting the PRA inputs were also examined for insights. External events with potential quantitative influence on the results of the AOT assessment are incorporated in the model quantification.

- Specific modeling items associated with the EDG AOT extension PRA application model include:

  - The EDGs are modeled as emergency AC power supplies to their associated safety related buses. No cross ties are modeled between these emergency buses.
  - Crew actions to perform EOP and SAMG response actions are included in the PRA. No EDG repair is currently included in the PRA as a recovery action.
  - The EDG AOT evaluation identifies certain compensatory measures that could be invoked. These are discussed in this section along with their quantitative impact.
  - The Salem 3 Gas Turbine has been removed from the model to conservatively reflect the potential future site configuration if Salem 3 is retired.

The Hope Creek internal events PRA is a thorough and detailed PRA model that is robust and capable of supporting the risk-informed decision to increase the EDG

Allowed Outage Times from 72 hours to 14 days. See Section 4 for a discussion of the PRA technical adequacy.

3.2 ASSUMPTIONS

The PRA quantitative evaluation of the extended EDG AOT has a number of assumptions. This subsection lists some of the important assumptions. Refer to Appendix B for further discussion of assumptions and model uncertainty.

- An extended EDG outage will occur for both EDG A and B every PM cycle. This overestimates the impact of these outages on the HCGS risk profile. The EDG PMs will be performed on a 24 month cycle and the estimated durations are much less than 14 days[(1)]. Therefore, the ΔCDF and ΔLERF assessments of assuming 14 days for each EDG every 24 months is conservative.
- The risk contributions from the different divisional diesel generators is quite different. The ICCDP evaluation does not average the results to recognize this asymmetric effect. Rather, the worst case ICCDP is generally represented by the worst configuration.
- The external event analysis is quantitative and is based on the IPEEE PRA models which have been incorporated into the internal events updated PRA model. The external events models have previously been reviewed by the NRC but not against the ANS PRA Standards.
- Forcing the diesel generator outage to occur during a shutdown (e.g., a refueling outage) is expected to introduce a significant risk. There is not a shutdown PRA maintained for HCGS, and therefore, the risk decrease associated with removing the EDG overhaul from the outage is not quantified. The change in the Technical Specification AOT for A and B EDGs would result in removing this shutdown risk increment. This unquantified risk reduction would reduce the calculated risk metrics of ΔCDF, ΔLERF, ICCDP, and ICLERP calculated in this report. However, the quantitative effect of risk changes during shutdown are not explicitly included in the quantification. The shutdown risk change will result in increased safety because the EDG work window will be removed from the outage. This can be a high risk evolution. By not including the risk benefit associated with the outage safety improvement, the at-power results provided in the enclosed analysis will be conservative.

(1) Estimated to be 3.5 to 5 days depending on the scope.

- The base risk model has not increased the EDG maintenance unavailabilities to account for future potential increases in the average unavailabilities. If this were to be included in the base risk model, it would result in improving the calculated risk metrics and showing an increase in the margin from the calculated risk metrics to their acceptance guidelines.
- Corrective and preventative maintenance outages have been combined to calculate a total maintenance unavailability. This is consistent with the ASME PRA Standard (Addendum C).
- Common cause failure events are treated using the latest INL common cause data base developed under the auspices of the NRC.
- For corrective maintenance outages, the PSEG practice (and Technical Specification Requirement) is to demonstrate that other similar components are not subject to the same failure, i.e., that there is no common cause link. This is part of the HCGS Technical Specifications[(1)]. Therefore, no model adjustment is made to reflect an increased potential for common cause if one component is OOS for corrective maintenance.
- Seismic: The HEPs are also modified to reflect the increased probability of failure under seismic events (e.g., increased stress, increased work load, limitations in access).
- Seismic: The seismic hazard curves used in the quantification and from EPRI NP-6395-D, Probabilistic Seismic Hazard Evaluation at Nuclear Power Plant Sites in the Central and Eastern United States. [23]
- Seismic: LERF treatment of seismic events is the same as in the internal events analysis. This may introduce some non-conservative bias in the base model but is judged to have limited impact on the risk metrics for this PRA application because the incremental increase in seismic risk is attributable to low magnitude seismic events. (See Appendix A for further discussion of this.)

(1) If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated.

3.3 COMPENSATORY MEASURES

PSEG performed a feasibility study prior to embarking on the EDG A and B AOT extension request. As part of that study, it was identified that it would be prudent to invoke a set of compensatory measures that would increase the available margin to the acceptance guidelines.

The following compensatory measures consistent with the EDG C and D AOT bases are included for the A and B AOT extension risk assessment:

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).
2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.
3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the same mechanical division (C or D, respectively) must be capable, operable and available to mitigate the consequence of a LOOP condition.
4. The removal from service of safety systems (e.g., HPCI or RCIC) and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.
5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.
6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

The practical implementation of these compensatory measures in the PRA model has taken the following approach:

- Compensatory measures 1 and 2 are general philosophical additions to the conduct of operations. Minimal quantitative credit is included in the risk metric calculations as discussed in Section 3.4 (Table 3.4-2). However, it is judged that these compensatory measures are important in maintaining a low risk increment.
- Compensatory measures 3 through 6 are explicitly included in the PRA models to assess their effect on the risk metrics specified in RG 1.174 and 1.177. These changes are implemented as discussed in Section 3.4 (Table 3.4-2).

3.4 CALCULATIONAL APPROACH

3.4.1 Overview

The Hope Creek base at-power PRA application specific model[1] incorporating internal and external events (i.e., the application specific model) has the following results:

Risk Metric	Frequency (Per Yr)	Surrogate Safety Goal (Per Yr)
CDF	2.18E-05[1]	1E-4
LERF	7.91E-07[2]	1E-5

(1) At truncation of 1E-12/yr using the single top PRA model.
(2) At truncation of 1E-12/yr using the single top PRA model.

The CDF risk metric meets the NRC surrogate safety goal with margin. See Section 3.4.3 for a further discussion of the application specific model.

3.4.2 Risk Metric Calculational Approach

To determine the effect of the proposed 14 day Allowed Outage Time for restoration of an inoperable EDG, the guidance in Regulatory Guides 1.174 and 1.177 is used. Thus, the following risk metrics are used to evaluate the risk impacts of extending the EDG Allowed Outage Time from 3 days (72 hours) to 14 days:

(1) Hope Creek PRA EDG AOT Extension Application Model.

Regulatory Guide 1.174

ΔCDF_{AVE} = change in the annual average CDF due to any increased on-line maintenance unavailability of EDGs that could result from the increased Allowed Outage Time. This risk metric is used to compare against the criteria of Regulatory Guide 1.174 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, CDF_{BASE}.

$\Delta LERF_{AVE}$ = change in the annual average LERF due to any increased on-line maintenance unavailability of EDGs that could result from the increased Allowed Outage Time. Regulatory Guide 1.174 criteria were also applied to judge the significance of changes in this risk metric.

Regulatory Guide 1.177

ICCDP{EDG Y} = incremental conditional core damage probability with EDG Y out-of-service for an interval of time equal to the proposed new Allowed Outage Time (14 days). This risk metric is used as suggested in Regulatory Guide 1.177 to determine whether a proposed increase in Allowed Outage Time has an acceptable risk impact.

ICLERP{EDG Y} = incremental conditional large early release probability with EDG Y out-of-service for an interval of time equal to the proposed new Allowed Outage Time (14 days). Regulatory Guide 1.177 criteria were also applied to judge the significance of changes in this risk metric.

The evaluation of the above risk metrics is performed as follows.

The change in the annual average CDF due to the extension of the A and B EDG Allowed Outage Time, ΔCDF_{AVE}, is evaluated by computing the following:

$$CDF_{AVE} = \left(\frac{T_A}{T_{CYCLE}}\right)CDF_{A-OOS} + \left(\frac{T_B}{T_{CYCLE}}\right)CDF_{B-OOS} + \left(1 - \frac{T_A + T_B}{T_{CYCLE}}\right)CDF_{base} \qquad [Eq.\ 1]$$

where:

CDF_{BASE} = baseline annual average CDF with average unavailability of EDGs consistent with the current EDG Allowed Outage Time.

$CDF_{A\text{-}OOS}$ = CDF evaluated from the PRA model with the EDG train A out-of-service and compensatory measures for EDG A implemented. These compensatory measures include prohibiting concurrent maintenance or inoperable status of the remaining diesel generator on the same division (i.e., the C EDG) as well as other compensatory measures identified in this evaluation.

$CDF_{B\text{-}OOS}$ = CDF evaluated for the PRA model with the EDG train B out-of-service and compensatory measures for EDG B implemented. These compensatory measures include prohibiting concurrent maintenance or inoperable status of the remaining diesel generator on the same division (i.e., the D EDG) as well as other compensatory measures identified in this evaluation.

T_A = Total time per 24 month EDG preventive maintenance cycle (T_{CYCLE}) that EDG A is out-of-service for the extended Allowed Outage Time -- Assumed to be 14 days[(1)]

T_B = Total time per 24 month EDG preventive maintenance cycle (T_{CYCLE}) that EDG B is out-of-service for the extended Allowed Outage Time -- Assumed to be 14 days[(1)]

T_{Cycle} = 24 months of operation which includes 30 days for refueling (730 days - 30 days = 700 days)

$$CDF_{AVE} = CDF_{A-OOS} \times \frac{14\,days}{700\,days} + CDF_{B-OOS} \times \frac{14\,days}{700\,days} + $$

$$+ CDF_{Base} \times \frac{672\,days}{700\,days} \qquad [Eq.\ 2]$$

$$\Delta CDF_{AVE} = CDF_{AVE} - CDF_{BASE} \qquad [Eq.\ 3]$$

(1) It is not expected that the A and B EDGs will undergo a full 14 day outage every 24 month preventive maintenance cycle. Nevertheless, for this risk metric calculation, it is conservatively assumed that both A and B EDGs receive full 14 day AOTs during each 24 month EDG maintenance cycle. (Note that the C and D EDG outage data is already accounted for in the Base PRA calculation.)

where,

CDF_{AVE} = Average CDF over a "typical" 24 month preventive maintenance cycle

ΔCDF_{AVE} = Difference between CDF with current technical specifications on EDGs and the CDF for an average 24 month cycle with the EDG Allowed Outage Time extended to 14 days.

Figure 3.4-1 provides a graphical display of the cycle evaluation for the RG 1.174 risk evaluation.

A similar approach was used to evaluate the change in the average LERF due to the requested Allowed Outage Time, $\Delta LERF_{AVE}$:

$$LERF_{AVE} = \left(\frac{T_A}{T_{CYCLE}}\right) LERF_{A-OOS} + \left(\frac{T_B}{T_{CYCLE}}\right) LERF_{B-OOS} + \left(1 - \frac{T_A + T_B}{T_{CYCLE}}\right) LERF_{BASE} \quad [Eq.\ 4]$$

where:

$LERF_{BASE}$ = baseline annual average LERF with average unavailability of EDGs consistent with the current EDG Allowed Outage Time. This is the LERF result of the current baseline PRAs. (See discussion under CDF_0 and above.)

$LERF_{A-OOS}$ = LERF evaluated from the PRA model with the EDG train A out of service and compensatory measures for EDG A implemented. These compensatory measures include prohibiting concurrent maintenance or inoperable status of the remaining diesel generator on the same division (i.e., the C EDG) as well as other compensatory measures identified in this evaluation.

$LERF_{B-OOS}$ = LERF evaluated for the PRA model with the EDG train B out of service and compensatory measures for EDG B implemented. These compensatory measures include prohibiting concurrent maintenance or inoperable status of the remaining diesel generator on the same division (i.e., D EDG) as well as other compensatory measures identified in this evaluation.

$$\Delta LERF = LERF_{AVE} - LERF_{BASE} \quad [Eq.\ 5]$$

The evaluation was performed based on the assumption that the extended Allowed Outage Time would be applied to one major overhaul per EDG per 24 month preventive maintenance cycle, hence $T_{A\text{-}OOS} = T_{B\text{-}OOS} = 14$ days. The cycle time is based on the current 24 month EDG maintenance cycle. $T_{CYCLE} = 700$ days[(1)]. Note that the above formula for ΔCDF_{AVE} conservatively neglects the decrease in CDF from accidents initiated during shutdown that will result from the increased EDG availability of the EDGs during shutdown periods.

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) are computed using their definitions from Regulatory Guide 1.177. In terms of the above defined parameters, the definition of ICCDP for the "A" EDG is as follows:

$$ICCDP_A = (CDF_{A\text{-}OOS} - CDF_{BASE})T_{AOT} \qquad [Eq.6]$$

$$ICCDP_A = (CDF_{A\text{-}OOS} - CDF_{BASE}) * (14\ days) * (365\ days/year)^{-1} \qquad [Eq.7]$$

$$ICCDP_A = (CDF_{A\text{-}OOS} - CDF_{BASE}) * 3.84 \times 10^{-2}\ years \qquad [Eq.8]$$

Note that in the above formula 365 days/year is merely a conversion factor to provide the Allowed Outage Time units consistent with the CDF frequency units. The ICCDP values are dimensionless probabilities to evaluate the incremental probability of a core damage event over a period of time equal to the extended Allowed Outage Time. This should not be confused with the evaluation of ΔCDF_{AVE} in which the CDF is averaged over a 24 month EDG preventive maintenance cycle.

Similarly, ICLERP is defined as follows:

$$ICLERP_A = (LERF_{A\text{-}00S} - LERF_{BASE}) * 3.84 \times 10^{-2} years \qquad [Eq.9]$$

(1) 24 months of operation includes a 30 day outage for refueling. (730 days - 30 days = 700 days)

3.4.3 Base Model: EDG AOT Extension PRA Application Model

The Base PRA model of record (MOR) has been reviewed for applicability for the HCGS AOT. The following changes and reviews have been included in the base model used for the EDG AOT extension risk application:

- One of the changes anticipated at the plant is that the Salem Unit 3 Gas Turbine will be retired. This would eliminate one of the AC power sources potentially available to Hope Creek. Therefore, the "base model" calculation[(1)] is performed as if the Salem Unit 3 Gas Turbine has been permanently shut down. Therefore, the Salem Unit 3 Gas Turbine has been removed from the MOR for the EDG AOT application model (Base Model and all sensitivities). This reflects the potential for the future configuration at Salem Hope Creek without the Gas Turbine. This represents a slight conservatism in the calculated risk metrics relative to the case assuming it is available, as it is currently.
- A change to the MOR as a result of implementing an item from the Hope Creek PRA update database has been included in the EDG AOT Application Model to reflect some minor changes in the Level 2 related to credit for post RPV failure injection. These changes involved removal of some non-conservatisms in the MOR which slightly increased the LERF.
- A review of the LOOP frequency and EDG unavailability based on operating experience data was performed (see discussion below describing this review). No changes to the MOR were made based on these confirmatory reviews.
- Based upon the assessment of external events in Appendix A, the IPEEE modeling of seismic and fire hazards has been integrated into the Application Specific Model.

The above model changes have been incorporated into an application specific PRA model to support the Hope Creek EDG AOT risk evaluation. [27] The model calculations are performed to develop the increase in risk associated with those configurations that have a diesel generator out for an extended AOT. These

(1) Note that this modeling change results in a small increase in the CDF for the "Base Model" used in the EDG AOT calculations. This translates into larger ΔCDF and ICCDP for the EDG AOT risk metrics. No change in LERF is observed for the "No Gas Turbine" case because the Gas Turbine is only credited for late SBO events which are non-LERF contributors.

calculations along with the base model calculations are used to develop the risk metrics for comparison with RG 1.174 and RG 1.177 acceptance guidelines.

Operating Experience -- EDG Unavailability

For the base model, it is a useful perspective to note the EDG unavailabilities that are already included in the PRA model. Table 3.4-0 shows the operating experience data for the individual EDGs. Note that despite the fact that EDG C and D have an extended 14 day AOT approved in the Technical Specifications, PSEG has not abused this flexibility, i.e., the EDG unavailabilities are similar for all four EDGs.

Operating Experience Review -- LOOP Frequency

As part of the preparation of the Hope Creek PRA model, a review of Hope Creek operating experience was performed. This included an investigation of whether any loss of offsite AC power events have occurred at Hope Creek.

The Hope Creek Generating Station operating experience review revealed no instances of loss of offsite AC power initiators. This was confirmed by a review of NUREG/CR-6890 and an LER search of Hope Creek Operating history.

3.4.4 Compensatory Measures Evaluated

Table 3.4-1 summarizes the compensatory measures examined to increase the calculated margins to Regulatory Guide acceptance guidelines. Table 3.4-2 indicates how the PRA models have been changed to approximate the benefit to be achieved from the compensatory measures.

The evaluation of the impacts on the NRC specified risk metrics associated with the individual compensatory measures is a useful perspective to provide to decision makers. Therefore, the following two subsections provide the CDF, LERF, and incremental change in risk metrics for each Compensatory Measure.

3.4.5 Calculated CDF and LERF

Table 3.4-3 summarizes the calculated values for LERF and CDF for each of the individual compensatory measures and the cumulative effect of all of the compensatory measures.

Table 3.4-4 summarizes the EDG unavailabilities imposed on the PRA to represent the extended EDG AOT.

3.4.6 Risk Metrics

Table 3.4-5 summarizes the calculated values for the NRC specified risk metrics (ΔCDF, ΔLERF, ICCDP, and ICLERP) for the proposed change to the AOT for EDG A and B. These risk metrics are presented for each individual compensatory measure examined independently and for the compensatory measures examined together as a group.

The process used to calculate the risk metrics complies with the Regulatory Guides 1.174 and 1.177. Tables 3.4-6 through 3.4-9 provide example calculations for the ΔCDF, ΔLERF, ICCDP, and ICLERP for EDG A and B assuming that no compensatory measures are implemented.

The following subsections summarizes the insights from these quantifications.

3.4.7 Observations from the Risk Metric Calculations

The risk metric calculations provide valuable qualitative insights into managing risk. These insights are to be folded back into the Configuration Risk Management Program (CRMP). These observations include the following:

- Hazards

  The calculations are performed for the PRA model including internal events, internal floods, internal fires, and seismic effects.

- Contributors

  The principal contributors to the change in risk metrics for all compensatory measures are from the internal events PRA. The seismic PRA contributes only a small quantitative change to the risk metrics and the fire PRA contributors also represent small incremental changes.

  For the EDG OOS cases, the seismic induced LOOP events with EDGs not failed by the seismic event are the dominant contributors to the delta risk. These are the relatively low magnitude seismic events. Accident scenarios involving postulated seismic-induced EDG failure have no contribution to the delta risk estimates of this analysis. This fact is due to the high correlation of seismic induced failures of similar equipment in like locations. Input from fragility experts indicates that there is a strong correlation among similar equipment on the same floor such that seismic induced failure of one component is perfectly correlated with failure of the similar components, i.e., all EDGs would be failed (this is a standard seismic PRA modeling approach). Therefore, for accident scenarios involving seismic induced EDG failure, there is no difference in the CDF whether one of the EDGs is OOS for maintenance or not.

  Most of the accident initiators in the fire PRA do not contribute to the changes in risk metrics for the extended EDG AOT because the fire initiators either: (a) do not challenge offsite AC power (i.e., when the EDGs would be required); or, (b) lead to failures of both offsite AC power AND the EDGs.

- These calculations are all reported assuming the entire 14 day AOT is used and that the compensatory measures are implemented for the entire 14 day extended AOT. This leads to some conservatism in the assessments presented to decision makers.

- Asymmetry

  The results indicate that the A and C mechanical division has a smaller overall contribution to the changes in risk metric than the B and D mechanical division. The dominance of the B&D division in the quantitative analysis is directly related to its support of the depressurization function which, if failed, would preclude access to the multiple low pressure injection systems. The A&C divisions do not support the Hope Creek RPV depressurization function.

- Compensatory Measure 3: Prevent Coincident Planned EDG Maintenance (A&C or B&D)

  Implementation of only Compensatory Measure 3 results in all risk metrics meeting the acceptance guidelines from the Regulatory Guides 1.174 and 1.177.

- Compensatory Measure 4: Prevent Coincident HPCI and RCIC Maintenance with EDG A or B OOS

  Implementation of only Compensatory Measure 4 results in all risk metrics meeting the acceptance guidelines from the Regulatory Guides 1.174 and 1.177. However, the margin to the limits is less than seen when Compensatory Measure 3 alone is implemented.

- Compensatory Measure 5: Minimize Testing of Sensitive Equipment with EDG A or B OOS

  Implementation of only Compensatory Measure 5 results in all risk metrics except ICLERP for EDG B meeting the acceptance guidelines from the Regulatory Guides 1.174 and 1.177. However, the margin to the limits is much less than seen when Compensatory Measure 3 alone is implemented. The margins are approximately the same as the Base Case, i.e., very little calculated benefit from this Compensatory Measure.

- Compensatory Measure 6: Preclude Entry into Extended EDG AOT during Anticipated Severe Weather

  Implementation of only Compensatory Measure 6 results in all risk metrics except ICLERP for EDG B meeting the acceptance guidelines from the Regulatory Guides 1.174 and 1.177. The CDF margins are much improved from the base case, but the EDG B ICLERP is unchanged.

- Compensatory Measures 3-6: Combination of Compensatory Measures 3 through 6

  Implementation of Compensatory Measures 3 to 6 results in all risk metrics meeting the acceptance guidelines from the Regulatory Guides 1.174 and 1.177. Significant margin is provided by the incorporation of these compensatory measures.

3.4.8 Results Summary

The calculated results for the PRA models that include both internal and external events are shown in Table 3.4-10.

The results are shown for the application model base case and the case when compensatory measures are incorporated into the Hope Creek planning process. The results in Table 3.4-10 are also compared with the acceptance guidelines that are specified by the NRC in RG 1.174 and RG 1.177.

As can be seen from the calculations for the base model[(1)] with no compensatory measures incorporated, the following results are identified:

- The ΔCDF and ΔLERF risk metrics are within the RG 1.174 acceptance guidelines for Region III, i.e., very small risk change.
- The ICCDP for EDG A is below the RG 1.177 acceptance guideline.
- The ICCDP for EDG B is slightly above the RG 1.177 acceptance guideline.
- The ICLERP for EDG A is well below the RG 1.177 acceptance guideline.
- The ICLERP for EDG B is slightly above the RG 1.177 acceptance guideline.

Therefore, compensatory measures are judged prudent to reduce the ICCDP and ICLERP for EDG B below the acceptance guidelines of RG 1.177 and provide additional margin for the other risk metrics to their acceptance guidelines. In addition, the compensatory measures also provide additional margin to account for possible uncertainties in the quantitative calculations.

It is noted that for the case that implements the Compensatory Measures 3 through 6, Column 3 of Table 3.4-10, all of the risk metrics are well below the acceptance guidelines. This is a good indication that the risk associated with this proposed extension of the EDG AOT is very small.

(1) Base application model includes the assumption that no Salem 3 Gas Turbine is available.

The next subsection presents a review of the EDG AOT Extension Application Model to identify the dominant contributors to the baseline risk and those dominant contributors to the change in risk associated with the EDG AOT extension.

Table 3.4-0

EDG UNAVAILABILITY DATA

EDG OOS	Hours Unavailable (A)[1]	Critical Hours (B)	Unavailability (A/B)
EDG A	415.28	33610	1.24E-2
EDG B	458.99	33610	1.37E-2
EDG C	626.22	33610	1.86E-2
EDG D	247.24	33610	0.74E-2
Total	1747.73	134440	1.3E-2

(1) Depending on the scope of the 24-month Preventive Maintenance (PM), the time will vary from 3.5 days to 5 days. These durations are not the LCO times, but rather the MRule unavailability durations.

The 3.5 days to 5 days per 24 months is equivalent to an EDG unavailability of 4.8E-3 to 6.8E-3.

While the PM is expected to require 3.5 to 5 days, it is prudent to have a AOT that is approximately twice the PM. In addition, major overhauls (15 year periodicity) can also be accommodated within this AOT.

Table 3.4-1

COMPENSATORY MEASURES FOR USE DURING EXTENDED EDG OUTAGES

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).
2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.
3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the associated mechanical division (A&C or B&D) must be capable, operable and available to mitigate the consequence of a LOOP condition.
4. The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.
5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.
6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

Table 3.4-2

EDG AOT EXTENSION ANALYSIS:
SUMMARY OF HCGS PRA MODELING APPROACHES USED TO CREDIT COMPENSATORY MEASURES

Compensatory Measure	HCGS Modeling Approach
1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).	This is treated under Item #4.
2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.	Configuration Risk Management essentially precludes voluntary entry into these conditions. (See Items 4 and 5 below.)
3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the mechanical division (A&C or B&D) must be capable, operable and available to mitigate the consequence of a LOOP condition.	Ensure that the appropriate EDG maintenance terms are properly treated by excluding those combinations of diesel generator maintenance that are explicitly prohibited i.e., A AND C or B AND D diesel generators.
4. The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.	Precludes coincident maintenance unavailability of HPCI and EDG or RCIC and EDG.
5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.	Reduce the turbine trip frequency for the EDG OOS PRA evaluation by 10%(1).
6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.	Reduce the LOOP frequency from severe weather by 75% for the EDG OOS configuration PRA evaluation.

(1) This reduction in turbine trip frequency is a conservative estimate of the reduction in challenges to spurious shutdowns when Compensatory Measures #2 and #5 are implemented. This is also a reflection of the benefit associated with these measures in preventing automatic scrams with configurations identified in the Tier 2 investigation in Appendix D.

Table 3.4-3

HOPE CREEK PRA RESULTS
WITH EDG A OR EDG B OOS
(PRA INCLUDES INTERNAL AND EXTERNAL EVENTS)

Internal and External Events			
Case	CDF (/yr)	LERF (/yr)	Comment
Gas Turbine Unavailable - EDG A and B OOS Application Model Base Case			
Base Case	2.18E-05	7.91E-07	Set basic event ACP-GTS-FS (Gas Turbine) to TRUE.
EDG A OOS	2.80E-05	8.26E-07	Set basic events DGS-DGN-FR-AG400 (EDG A) and ACP-GTS-FS to TRUE.
EDG B OOS	3.49E-05	2.23E-06	Set basic events DGS-DGN-FR-BG400 (EDG B) and ACP-GTS-FS to TRUE.
Compensatory Measure 3: Prevent Coincident Planned EDG A maintenance A&C or B&D)			
EDG A OOS	2.79E-05	8.24E-07	Set basic events DGS-DGN-FR-AG400 and ACP-GTS-FS to TRUE. DGS-DGN-TM-CG400 (EDG C) set to FALSE.
EDG B OOS	3.29E-05	1.94E-06	Set basic events DGS-DGN-FR-BG400 and ACP-GTS-FS to TRUE. DGS-DGN-TM-DG400 (EDG D) set to FALSE.
Compensatory Measure 4: Prevent Coincident HPCI and RCIC Maintenance with EDG A or B OOS			
EDG A OOS	2.77E-05	8.08E-07	Set basic events DGS-DGN-FR-AG400 and ACP-GTS-FS to TRUE. HPI-TDP-TM-OP204 (HPCI) and RCI-TDP-TM-OP203 (RCIC) set to FALSE.
EDG B OOS	3.36E-05	2.01E-06	Set basic events DGS-DGN-FR-BG400 and ACP-GTS-FS to TRUE. HPI-TDP-TM-OP204 and RCI-TDP-TM-OP203 set to FALSE.
Compensatory Measure 5: Minimize Testing of Sensitive Equipment with EDG A or B OOS			
EDG A OOS	2.79E-05	8.18E-07	Set basic events DGS-DGN-FR-AG400 and ACP-GTS-FS to TRUE. %IE-TT set to 6.33E-1 (Reduction of 10%).
EDG B OOS	3.47E-05	2.21E-06	Set basic events DGS-DGN-FR-BG400 and ACP-GTS-FS to TRUE. %IE-TT set to 6.33E-1.
Compensatory Measure 6: Precluding Entry During anticipated Severe Weather			
EDG A OOS	2.48E-05	8.16E-07	Set basic events DGS-DGN-FR-AG400 and ACP-GTS-FS to TRUE. LOOP-IE-SW (LOOP initiator due to Severe Weather) set to 5.25E-2 (Reduced by 75%).
EDG B OOS	3.21E-05	2.22E-06	Set basic events DGS-DGN-FR-BG400 and ACP-GTS-FS to TRUE. LOOP-IE-SW set to 5.25E-2.
Compensatory Measures 3-6: Combined Compensatory Measures 3 through 6			
EDG A OOS	2.44E-05	7.89E-07	Set basic events DGS-DGN-FR-AG400 and ACP-GTS-FS to TRUE. Include all above comp measures 3 through 6.
EDG B OOS	2.89E-05	1.70E-06	Set basic events DGS-DGN-FR-BG400 and ACP-GTS-FS to TRUE. Include all above comp measures 3 through 6.

Table 3.4-4

EDG MAINTENANCE UNAVAILABILITIES FOR CALCULATIONS OF ΔCDF AND ΔLERF RISK METRICS

Case	Planned Maintenance Unavailabilities to be Imposed[3]	
	EDG A Unavailable	EDG B Unavailable
1: $CDF_{A\text{-}OOS}$	2.00E-2[1]	0
2: $CDF_{B\text{-}OOS}$	0	2.00E-2[1]
3: CDF_{BASE}[1]	Random[2]	Random[2]

(1) $\dfrac{14 \text{ days}}{700 \text{ days}^{(a)}} = 2.00\text{E-}2$

(2) D/G Planned Maintenance Unavailability Set to historical unavailability assessment for Hope Creek. This case is considered representative of current plant operation.

(3) Note that a sensitivity case in Appendix B identifies the effects of adding the current EDG maintenance unavailabilities to these EDG unavailabilities.

(a) 24 months of operation which includes 30 days for refuel. (730 days - 30 days = 700 days).

Table 3.4-5

QUANTITATIVE RESULTS OF THE RISK METRICS
FOR EDG A&B OOS WITH CONSIDERATION OF COMPENSATORY MEASURES
(PRA INCLUDES BOTH INTERNAL AND EXTERNAL EVENTS)

Case Description	ΔCDF (per yr)	ΔLERF (per yr)	ICCDP		ICLERP	
			EDG A OOS	EDG B OOS	EDG A OOS	EDG B OOS
Base Case (Gas Turbine removed from service)	3.86E-07	2.95E-08	2.38E-07	5.02E-07	1.35E-09	5.53E-08
Compensatory Measure 3 Prevent Coincident Planned EDG Maintenance (A&C or B&D)	3.44E-07	2.36E-08	2.34E-07	4.26E-07	1.27E-09	4.41E-08
Compensatory Measure 4 Prevent Coincident HPCI and RCIC Maintenance with EDG A or B OOS	3.54E-07	2.47E-08	2.26E-07	4.53E-07	6.54E-10	4.68E-08
Compensatory Measure 5 Minimize Testing of Sensitive Equipment with EDG A or B OOS	3.80E-07	2.89E-08	2.34E-07	4.95E-07	1.04E-09	5.44E-08
Compensatory Measure 6 Preclude entry into extended EDG AOT during Anticipated Severe Weather	2.66E-07	2.91E-08	1.15E-07	3.95E-07	9.61E-10	5.48E-08
Compensatory Measures 3-6	1.94E-07	1.81E-08	9.96E-08	2.72E-07	<1.00E-10	3.49E-08

Table 3.4-6

CDF CALCULATIONS FOR HOPE CREEK
EDG "A" AND "B" OOS WITH NO COMPENSATORY MEASURES

Average CDF after AOT Extension Included

[Use Eq. 2]

$$CDF_{AVE} = 2.80E\text{-}5/yr \bullet 2.00E\text{-}2^{(1)} + 3.49E\text{-}5/yr \bullet 2.00E\text{-}2 + 2.18E\text{-}5/yr \bullet 0.96^{(2)}$$

$$CDF_{AVE} = 5.60E\text{-}7/yr + 6.98E\text{-}7/yr + 2.09E\text{-}5/yr$$

$$CDF_{AVE} = 2.22E\text{-}5/yr$$

Change in CDF

[Use Eq. 3]

$$\Delta CDF = CDF_{AVE} - CDF_{BASE}$$

$$\Delta CDF = 2.22E\text{-}5/yr - 2.18E\text{-}5/yr^{(1)}$$

$$\Delta CDF = 3.86E\text{-}7/yr$$

(1) Based on planned EDG PM every 2 years. However, depending on the scope of the 24-month PM, the time will vary from 3.5 days to 5 days. These durations are not the LCO times, but rather the MRule unavailability durations.

(2) Accounts for 30 days/2 years in refuel outage.

Table 3.4-7

LERF CALCULATIONS FOR HOPE CREEK
EDG "A" AND "B" OOS WITH NO COMPENSATORY MEASURES

Average LERF after AOT Extension Included

[Use Eq. 4]

$$LERF_{AVE} = 8.26E\text{-}7/yr \bullet 2.00E\text{-}2^{(1)} + 2.23E\text{-}6/yr \bullet 2.00E\text{-}2 + 7.91E\text{-}7/yr \bullet 0.96^{(2)}$$

$$LERF_{AVE} = 1.65E\text{-}8/yr + 4.46E\text{-}8/yr + 7.59E\text{-}7/yr$$

$$LERF_{AVE} = 8.20E\text{-}7/yr$$

Change in LERF

[Use Eq. 5]

$$\Delta LERF = 8.20E\text{-}7/yr - 7.91E\text{-}7/yr$$

$$\Delta LERF = 2.95E\text{-}8/yr$$

(1) Based on planned EDG PM every 2 years. However, depending on the scope of the 24-month PM, the time will vary from 3.5 days to 5 days. These durations are not the LCO times, but rather the MRule unavailability durations.

(2) Accounts for 30 days/2 years in refuel outage.

Table 3.4-8

ICCDP CALCULATION
EDG "A" AND "B" OOS WITH NO COMPENSATORY MEASURES
[Eq. 6]

A: $ICCDP = (CDF_{A\text{-}OOS} - CDF_{BASE}) \bullet 3.84E\text{-}2$ *years*

$= (2.79E\text{-}5 - 2.18E\text{-}5/yr) \bullet 3.84E\text{-}2$ *years*

$= 2.34E\text{-}7$

B: $ICCDP = (CDF_{B\text{-}OOS} - CDF_{BASE}) \bullet 3.84E\text{-}2$ *years*

$= (3.49E\text{-}5/yr - 2.18E\text{-}5/yr) \bullet 3.84E\text{-}2$ *years*

$= 5.02E\text{-}7$

Table 3.4-9

ICLERP CALCULATION
EDG "A" AND "B" OOS WITH NO COMPENSATORY MEASURES
[Eq. 6]

$$A: \quad ICLERP = (LERF_{A\text{-}OOS} - LERF_{BASE}) \bullet 3.84E\text{-}2 \text{ years}$$
$$= (8.26E\text{-}7 - 7.91E\text{-}7/yr) \bullet 3.84E\text{-}2 \text{ years}$$
$$= 1.35E\text{-}9$$

$$B: \quad ICLERP = (LERF_{B\text{-}OOS} - LERF_{BASE}) \bullet 3.84E\text{-}2 \text{ years}$$
$$= (2.23E\text{-}6/yr - 7.91E\text{-}7/yr) \bullet 3.84E\text{-}2 \text{ years}$$
$$= 5.53E\text{-}8$$

Table 3.4-10

COMPARISON OF QUANTITATIVE RESULTS
WITH ACCEPTANCE GUIDELINES
(PRA INCLUDES BOTH INTERNAL AND EXTERNAL EVENTS)

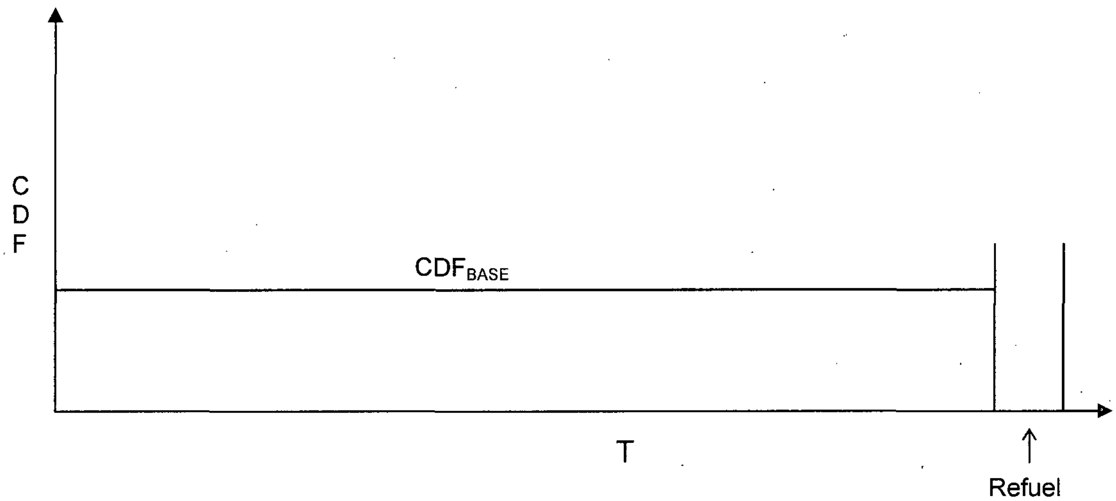
Risk Metric	Application Model (Base Case)[3]	PRA Model[3] with Compensatory Measures (3 through 6)	Acceptance Guidelines[1]
ΔCDF (/yr)	3.86E-07	1.94E-07	1.0E-06
ΔLERF (/yr)	2.95E-08	1.81E-08	1.0E-07
ICCDP EDG A	2.38E-07	9.96E-08	5.0E-07
ICCDP EDG B[2]	5.02E-07	2.72E-07	5.0E-07
ICLERP EDG A	1.35E-09	<1.00E-10	5.0E-08
ICLERP EDG B	5.53E-08[2]	3.49E-08	5.0E-08

(1) Acceptance Guidelines derived from RG 1.174 and RG 1.177.

(2) Exceeds Acceptance Guidelines.

(3) EDG AOT application specific model.

BEFORE TECH SPEC CHANGE



AFTER TECH SPEC CHANGE

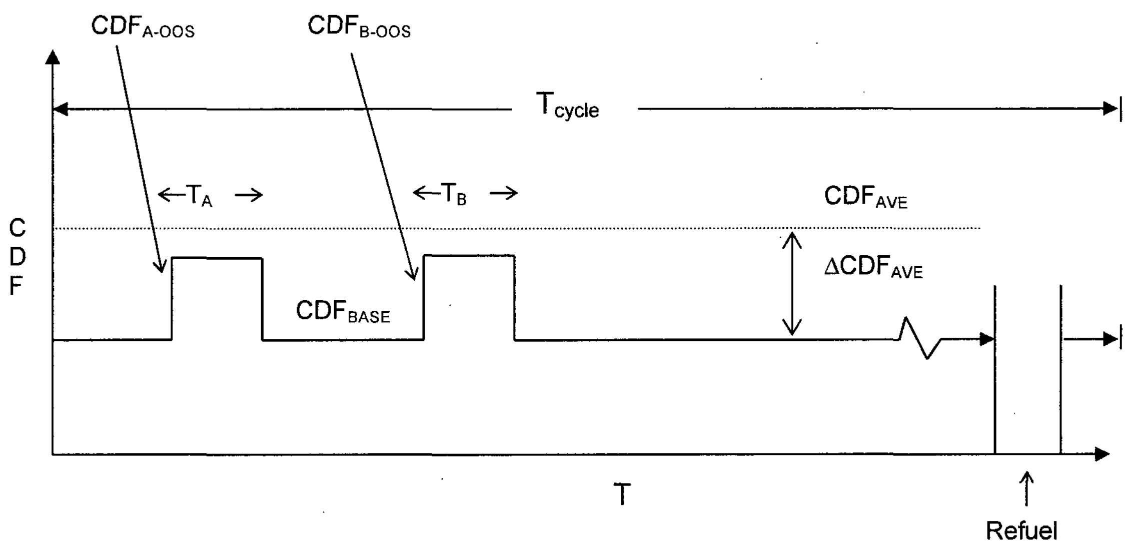


Figure 3.4-1 Typical Cycle Evaluation Used for Reg. Guide 1.174 Evaluation

3.5 DISTRIBUTION OF DOMINANT CONTRIBUTORS

The Hope Creek PRA model that includes internal events, internal flood hazards (referred to as the EDG AOT Extension Application Model) can also be examined for the distribution of initiating event and accident class contributors.

Table 3.5-1 shows the initiating event contributors to the at-power application model for the CDF risk metric calculations. Fire initiating events are the single largest contributor to this EDG AOT Extension Application Model CDF.

Table 3.5-2 shows the accident class contributors to the EDG AOT Extension Application Model for the CDF risk metric calculation. Accident Class IA (loss of makeup at high RPV pressure) is the largest accident class contributor to the base model CDF.

The Hope Creek EDG AOT Extension Application Model that includes internal events, internal floods, fires, and seismic hazards can also be examined for the distribution of initiating event and accident class contributors when:

- EDG “B” is OOS
- Compensatory Measures 3-6 are implemented

EDG B is selected as the EDG to be OOS in these calculations because it has the larger impact on the risk metrics.

Table 3.5-3 shows the initiating event contributors to the EDG AOT Extension Application Model CDF risk metric calculation with EDG B OOS and Compensatory Measures 3 through 6 are implemented. Again, fire initiating events are significant contributors, however, as expected LOOP initiating events take on an increased importance compared with Table 3.5-1.

Table 3.5-4 shows the accident class contributors to the EDG AOT Extension Application Model CDF risk metric calculations. The accident class contributors are still dominated by Class IA.

Finally, it is important to demonstrate the initiating event contribution to the change in the risk. This change in risk reflects the importance of initiating events to those cutsets and sequences that cause the risk to change as a result of EDG B being in an outage. Table 3.5-5 shows that it is not fire or seismic that dominate the determination of the change in risk, but the loss of offsite AC power (LOOP).

As can be seen from Table 3.5-6, the nature of the dominant accident classes which contributes to the delta-CDF for the "B" EDG OOS differs from the base model and the EDG "B" OOS configuration specific assessments. The Class IA sequence relative contribution drops by approximately 11% from the base case. There is a significant increase (17%) in the Class IB sequence relative contribution (Sum of Classes IBE and IBL) because of the LOOP initiating event importance. However, the drop in Class IA (11%) is not as large as might be anticipated because the unavailability of EDG B and D results in failure of effective RPV depressurization for the mission time (Class IA).

Table 3.5-1

HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY INITIATING EVENT
(EDG AOT EXTENSION APPLICATION MODEL WITH
INTERNAL AND EXTERNAL EVENTS)[1]

Initiating Event	CDF (/yr)	% Contribution to CDF
LOOP	1.01E-6	4.7%
Other Transients[2]	1.83E-6	8.4%
LOCA	7.56E-7	3.5%
Special IE and Internal Flood	1.73E-6	7.9%
Fire	1.56E-5	71.7%
Seismic	8.26E-7	3.8%
Total	2.18E-5	100%

(1) Model quantified with Gas Turbine Unavailable.

(2) Refer to Table 4-1 of Hope Creek Initiating Events Notebook for categorization of Initiating Events.

Table 3.5-2

BASE MODEL
HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY ACCIDENT CLASS
(EDG AOT EXTENSION APPLICATION MODEL WITH
INTERNAL AND EXTERNAL EVENTS)

Class	Description	CDF	% Contribution to CDF
CD-IA	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.(1)	1.77E-05	81.04%
CD-IBE	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 4 hours.)	5.32E-08	0.24%
CD-IBL	Class IBL is defined as "Late" Station Blackout events with core damage at greater than 4 hours.	7.69E-07	3.52%
CD-IC	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	4.55E-08	0.21%
CD-ID	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	1.41E-06	6.46%
CD-IIA	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	9.44E-07	4.32%
CD-IIL	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	1.87E-09	0.01%
CD-IIT	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced prior to containment failure.	1.87E-10	0.00%
CD-IIV	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment vent.	5.41E-08	0.25%
CD-IIIB	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	4.85E-07	2.22%
CD-IIIC	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	2.40E-08	0.11%

Table 3.5-2

BASE MODEL
HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY ACCIDENT CLASS
(EDG AOT EXTENSION APPLICATION MODEL WITH
INTERNAL AND EXTERNAL EVENTS)

Class	Description	CDF	% Contribution to CDF
CD-IIID	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	5.89E-08	0.27%
CD-IVA	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.60E-07	0.73%
CD-IVL	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	2.98E-09	0.01%
CD-V	Unisolated LOCA outside containment.	1.30E-07	0.60%
Total		2.18E-05	100%

(1) Class IA includes Class IE. Includes significant contribution from fire induced evaluation of Control Room and failure to mitigate the accident from the Remote Shutdown Panel.

Table 3.5-3

HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY INITIATING EVENT
EDG B OOS WITH COMPENSATORY MEASURES 3 THROUGH 6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)(1)

Initiating Event	CDF (/yr)	% Contribution to CDF
LOOP	6.69E-6	23.2%
Other Transients(2)	2.29E-6	7.9%
LOCA	9.3E-7	3.2%
Special IE and Internal Flood	1.77E-6	6.1%
Fire	1.62E-5	56.2%
Seismic	9.71E-7	3.4%
Total	2.89E-5	100%

(1) Model quantified with Gas Turbine Unavailable.

(2) Refer to Table 4-1 of Hope Creek Initiating Events Notebook for categorization of Initiating Events.

Table 3.5-4

HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY ACCIDENT CLASS
EDG B OOS WITH COMPENSATORY MEASURES 3-6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)[1]

Class	Description	EDGB OOS[2]	% Contribution of CDF
CD-IA	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.[3]	2.27E-05	78.57%
CD-IBE	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 4 hours.)	1.23E-07	0.43%
CD-IBL	Class IBL is defined as "Late" Station Blackout events with core damage at greater than 4 hours.	2.25E-06	7.79%
CD-IC	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	4.45E-08	0.15%
CD-ID	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	1.55E-06	5.36%
CD-IIA	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	1.13E-06	3.91%
CD-IIL	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	2.64E-08	0.09%
CD-IIT	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced prior to containment failure.	1.91E-10	0.00%
CD-IIV	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment vent.	7.21E-08	0.25%
CD-IIIB	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	5.59E-07	1.93%
CD-IIIC	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	6.10E-08	0.21%

Table 3.5-4

HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY ACCIDENT CLASS
EDG B OOS WITH COMPENSATORY MEASURES 3-6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)[1]

Class	Description	EDGB OOS[2]	% Contribution of CDF
CD-IIID	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	6.12E-08	0.21%
CD-IVA	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.82E-07	0.63%
CD-IVL	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	2.82E-09	0.01%
CD-V	Unisolated LOCA outside containment.	1.31E-07	0.45%
Total		2.89E-05	100%

(1) Model quantified with Gas Turbine Unavailable.
(2) Includes Compensatory Measures 3-6.
(3) Class IA includes Class IE. Includes significant contribution from fire induced evaluation of Control Room and failure to mitigate the accident from the Remote Shutdown Panel.

Table 3.5-5

DELTA-CDF EVALUATION
HOPE CREEK LEVEL 1 CDF
CONTRIBUTION BY INITIATING EVENT
EDG B OOS, WITH COMPENSATORY MEASURES 3 THROUGH 6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)[1]

Initiating Event	ΔCDF (/yr)	% Contribution to CDF
LOOP	5.68E-6	79.9%
Other Transients[2]	4.53E-7	6.4%
LOCA	1.74E-7	2.5%
Special IE and Internal Flood	3.92E-8	0.6%
Fire	6.19E-7	8.7%
Seismic	1.45E-7	2.0%
Total	7.1E-6	100%

(1) Model quantified with Gas Turbine Unavailable.

(2) Refer to Table 4-1 of Hope Creek Initiating Events Notebook for categorization of Initiating Events.

Table 3.5-6

SUMMARY OF CDF BY ACCIDENT SEQUENCE SUBCLASS FOR THE CONTRIBUTORS TO THE CHANGE IN RISK (CDF)
EDG B OOS WITH COMPENSATORY MEASURES 3-6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)(1)

Class	Description	Delta EDG B OOS(2)	%CDF
CD-IA	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.(3)	5.01E-06	70.91%
CD-IBE	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 4 hours.)	6.98E-08	0.99%
CD-IBL	Class IBL is defined as "Late" Station Blackout events with core damage at greater than 4 hours.	1.48E-06	20.98%
CD-IC	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	0.0	ε
CD-ID	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	1.39E-07	1.97%
CD-IIA	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	1.86E-07	2.63%
CD-IIL	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	2.45E-08	0.35%
CD-IIT	Accident sequences involving a loss of containment heat removal with the RPV initially intact core damage; core damage induced prior to containment failure.	3.85E-12	0.00%
CD-IIV	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment vent.	1.80E-08	0.25%

Table 3.5-6

SUMMARY OF CDF BY ACCIDENT SEQUENCE SUBCLASS FOR THE CONTRIBUTORS TO THE CHANGE IN RISK (CDF)
EDG B OOS WITH COMPENSATORY MEASURES 3-6
(EDG AOT EXTENSION APPLICATION MODEL WITH INTERNAL AND EXTERNAL EVENTS)(1)

Class	Description	Delta EDG B OOS(2)	%CDF
CD-IIIB	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	7.45E-08	1.05%
CD-IIIC	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	3.70E-08	0.52%
CD-IIID	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure or makeup systems.	2.30E-09	0.03%
CD-IVA	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	2.17E-08	0.31%
CD-IVL	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g., LOCA or SORV); core damage induced post containment failure.	0.0	0.00%
CD-V	Unisolated LOCA outside containment.	7.03E-10	0.00%
Total		7.10E-06	100%

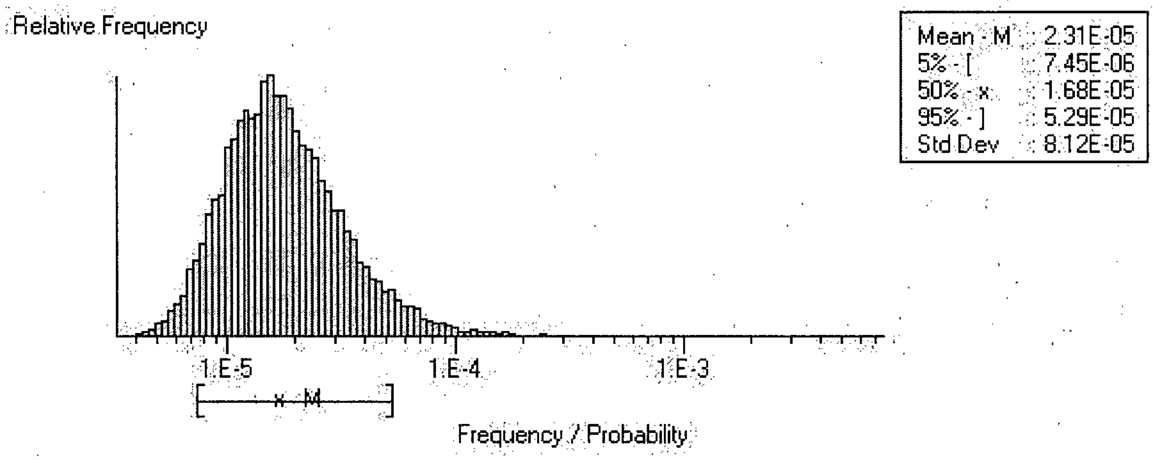
(1) Model quantified with Gas Turbine Unavailable.
(2) Includes Compensatory Measures 3-6.
(3) Class IA includes Class IE.

3.6 UNCERTAINTY EVALUATION

The evaluation of the CDF for the AOT assessment has been supported by a detailed qualitative and quantitative uncertainty evaluation. The parametric uncertainty quantification is performed using the CAFTA utility, UNCERT, to identify the effect of the parametric correlation. The uncertainty distribution on the CDF is shown in Figure 3.6-1.

In addition, a set of practical sensitivity evaluations have been performed to demonstrate the influence of some of the key assumptions in the assessment. These sensitivities are discussed in Appendix B and summarized in Section 5.

Hope Creek Uncertainty Quantification Summary



Note: CDF and LERF uncertainty quantification performed using cutsets generated from 1E-12/yr truncated point-estimate model quantifications

Figure 3.6-1 Parametric Uncertainty Distribution for Hope Creek CDF for the EDG AOT Extension Application Model (Includes Internal Events, Internal Flood, Seismic and Fire)

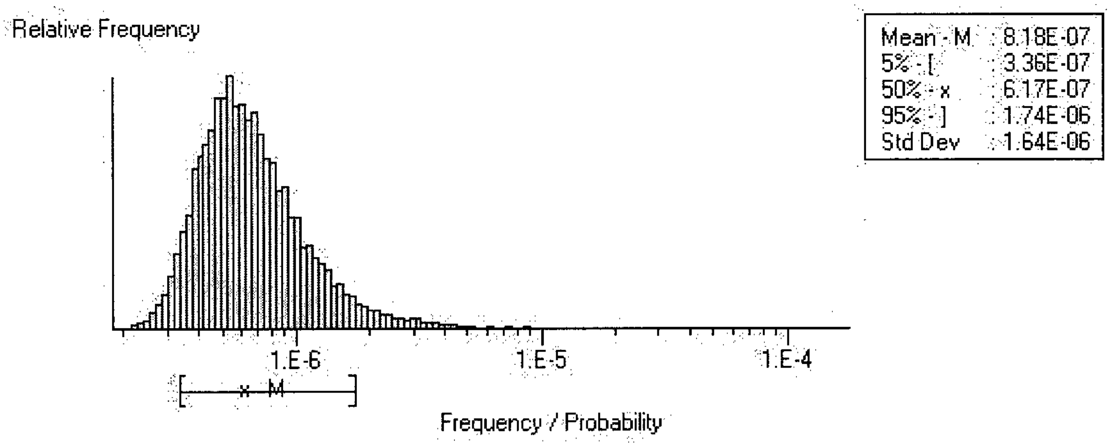


Figure 3.6-2 Parametric Uncertainty Distribution for Hope Creek LERF for the EDG AOT Extension Application Model (Includes Internal Events, Internal Flood, Seismic and Fire)

Section 4
TECHNICAL ADEQUACY OF THE PRA MODEL

This section summarizes the following with respect to the HCGS PRA and its technical adequacy:

- PRA Quality
- PRA Quantitative Summary
- External Event Considerations

4.1 PRA QUALITY

The HC108B version of the Hope Creek PRA model is the most recent evaluation of the risk profile at Hope Creek for internal event challenges. The Hope Creek PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the Hope Creek PRA is based on the event tree / fault tree methodology, which is a well-known methodology in the industry.

PSEG employs a multi-faceted approach to establishing and maintaining the technical adequacy and plant fidelity of the PRA models for all PSEG nuclear generation. This approach includes a proceduralized PRA maintenance and update process, appropriate peer reviews, and the use of self-assessments and Hope Creek PRA.

PRA quality is assured for the Hope Creek model and documentation through a combination of the following:

- Confirmation of the fidelity of the model with the as-built, as-operated plant (see Section 4.1.1)
- Use of methods and approaches consistent with the ASME PRA Standard
- Use of a PRA Peer Review (see Section 4.1.4) to identify areas of enhancement

- A self-assessment of the PRA against the ASME PRA Standard (see Section 4.1.5)
- Use of highly qualified PRA practitioners qualified under the PSEG PRA Program
- Use of internal reviews, interviews with the system engineers and the operating crew members
- Use of an Update Requirement Evaluation (URE) database to track potential model enhancements (See Section 4.1.6)
- The PRA Peer Review Process using the ASME PRA Standard (Note that the final report from the Peer Review Team had not been submitted prior to completion of the PRA update for HC108B.) (See Section 4.1.5.)

4.1.1 PRA Maintenance and Update

The PSEG risk management process ensures that the applicable PRA model remains an accurate reflection of the as-built and as-operated plants. This process is defined in the PSEG Risk Management program, which consists of a governing procedure (ER-AA-600, "Risk Management") and subordinate implementation procedures. PSEG procedure ER-AA-600-1015, "FPIE PRA Model Update" delineates the responsibilities and guidelines for updating the full power internal events PRA models at PSEG nuclear generation sites. The overall PSEG Risk Management program, including ER-AA-600-1015, defines the process for implementing regularly scheduled and interim PRA model updates, for tracking issues identified as potentially affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operating experience), and for controlling the model and associated computer files. To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plants, the following activities are routinely performed:

- The Site Risk Management Engineer (SRME) has reviewed the plant design modifications that could affect the risk profile and has identified those modifications to be explicitly accounted for in the PRA. These modifications have been included. This review has been extended from the PRA HC108B freeze date until 12/31/09. No new modifications affecting the PRA were identified.

- The Site Risk Management Engineer (SRME) has reviewed the procedure changes that could affect the risk profile and has identified those procedure changes to be explicitly accounted for in the PRA. These have been included. This review has been extended from the PRA HC108B freeze date until 12/31/09. No new procedures affecting the PRA were identified.
- Operating crews have been interviewed to assess their interpretation of procedures for key operator actions and the list of initiating events. These results are folded back into the Human Reliability Analysis (HRA), documented in the HRA Notebook, and then incorporated into the PRA model.
- System Managers have been interviewed to assess whether there have been any changes in the plant, the operating history, or system usage that would influence the PRA systems or initiating events. These results have been incorporated into the system models.
- The latest plant specific Maintenance Rule data has been examined and the results have been folded into the PRA data base using a Bayesian update process to calculate component failure data.

In addition to these activities, PSEG risk management procedures provide the guidance for particular risk management and PRA quality and maintenance activities. This guidance includes:

- Documentation of the PRA model, PRA products, and bases documents.
- The approach for controlling electronic storage of Risk Management (RM) products including PRA update information, PRA models, and PRA applications.
- Guidelines for updating the full power, internal events PRA models.
- Guidance for use of quantitative and qualitative risk models in support of the On-Line Work Control Process Program for risk evaluations for maintenance tasks (corrective maintenance, preventive maintenance, minor maintenance, surveillance tests and modifications) on systems, structures, and components (SSCs) within the scope of the Maintenance Rule (10CFR50.65 (a)(4)).

In accordance with this guidance, regularly scheduled PRA model updates nominally occur on an approximately 3-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, as-operated plant.

PSEG completed the HC108A update to the Hope Creek PRA model in September 2008, which was the result of a regularly scheduled update of the PRA model. PSEG subsequently completed the HC108B update to the Hope Creek PRA model in November 2008 to incorporate a significant procedural change involving SSW/SACS system operation and to resolve notable comments from the Hope Creek PRA Peer Review performed in October 2008.

As indicated previously, RG 1.200 also requires that additional information be provided as part of the LAR submittal to demonstrate the technical adequacy of the PRA model used for the risk assessment. Each of these items (plant changes not yet incorporated in to the PRA model, relevant peer review findings, consistency with applicable PRA Standards, and the identification of key assumptions) will be discussed in turn.

4.1.2 Plant Changes Not Yet Incorporated into the PRA Model

A PRA updating requirements evaluation (URE - PSEG PRA model update tracking database) is created for all issues that are identified that could impact the PRA model. The URE database includes the identification of those plant changes that could impact the PRA model.

The plant modifications and procedure changes since the freeze date for the PRA were reviewed as part of the preparation of the risk assessment for the A and B EDG AOT extension request. No plant modifications or procedure changes were identified that would significantly modify the PRA model or its quantification.

4.1.3 Applicability of Peer Review Findings and Observations

Several assessments of technical capability have been made, for the Hope Creek PRA model. These assessments are as follows and further discussed in the paragraphs below.

- An independent PRA peer review of the Hope Creek Rev. 0 PRA model (i.e., the Individual Plant Examination (IPE) model) was conducted as a pilot project under the auspices of the BWR Owners' Group in October 1996 following the DRAFT Industry PRA Peer Review process [13]. This peer review included an assessment of the PRA model maintenance and update process.
- A followup independent PRA peer review of the Hope Creek Rev. 1 PRA model was conducted under the auspices of the BWR Owners' Group in November 1999 following the revised Industry PRA Peer Review process [14]. This peer review included an assessment of the PRA model maintenance and update process.
- During 2005 and 2006, the Hope Creek PRA model results were evaluated in the BWR Owners' Group PRA cross-comparisons study performed in support of implementation of the mitigating systems performance indicator (MSPI) process.
- A PRA Peer Review of the Hope Creek HC108A PRA was performed during October 2008. The peer review was performed against Addendum B of the ASME PRA Standard [11]. The results of the PRA Peer Review indicated that a very small number of the supporting requirements (SRs) were "Not Met" for Capability Category II.

A summary of the disposition of the 1999 Industry PRA Peer Review facts and observations (F&Os) for the Hope Creek PRA models was documented as part of the statement of PRA capability for MSPI in the Hope Creek MSPI Basis Document [12]. As noted in that document, there were no open level A or level B F&Os from the 1999 peer review.

As indicated above, an additional formal peer review was performed in October 2008 and the final peer review report was issued in March 2009 [15]. This peer review was performed against Addendum B of the ASME PRA Standard [11], the criteria in RG 1.200, Rev. 1 [10] including the NRC positions stated in Appendix A of RG 1.200, Rev. 1, and further issue clarifications [16]. The October 2008 peer review identified supporting requirements (SRs) not meeting Capability Category II. Subsequent to the October 2008 peer review, the HC108B PRA model addressed and resolved many of the SRs that did not meet Capability Category II. The SRs that do not meet Capability

Category II for the current HC108B PRA model are summarized in Table 4.1-1 along with an assessment of the impact on the base PRA and their current status.

The PRA Peer Review process confirmed the adequacy of the Hope Creek PRA model for use in PRA applications.

The PRA Peer Review using the ASME PRA Standard resulted in the identification of some minor numerical changes to basic events and several additions to model logic. These changes led to a requantification of the Hope Creek PRA model resulting in the HC108B model.

All remaining gaps will be reviewed for consideration for the next periodic PRA model update, but are judged to have low impact on the PRA model or its ability to support a full range of PRA applications particularly the EDG AOT extension request. The remaining gaps are documented in the URE database so that they can be tracked and their potential impacts accounted for in applications where appropriate.

4.1.4 PRA Peer Reviews

The HCGS PRA has undergone two official Peer Reviews:

- A 1999 PRA Peer Review using the predecessor to the NEI PRA Peer Review Process, NEI 00-02. (This subsection discusses the results of that Peer Review.)
- A 2008 PRA Peer Review using the ASME PRA Standard as endorsed by RG 1.200. (See Section 4.1.5.)

4.1.4.1 BWROG PRA Peer Review

There has been a Hope Creek PRA Peer Review performed consistent with the NEI PRA Peer Review Predecessor Guidance and documented in a report to PSEG issued by the BWROG in 1999.

Table 4.1-1

GAPS TO CAPABILITY CATEGORY II OF THE ASME PRA STANDARD

Applicable SRs	Description of Gap	Related SRs	Importance to Application
DA-D1	Plant specific data was not collected for the most recent update reliability data. The only plant specific information used was for systems that are monitored by the MSPI program. MSPI systems include the diesel generators, HPCI, RCIC, RHR, SSWS and SACS. No other specific data was used for this update. Individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA. FINDING - As outlined in the Component Data Notebook, "individual component random failure data is a vital input to the PSA. Therefore, special attention is paid to ensuring that the best available information is used as input to the PSA." Inadequate data collection and update could have an actual impact on the accuracy of the PRA.		The majority of the high importance systems were updated with recent plant specifc data. These data updates included the EDGs. A review of Hope Creek recent experience indicates no anomalous behavior relative to the data used to characterize the other systems. Because the EDGs are among the data that were explicitly updated, this finding is judged to be of negligible impact on the conclusions of the application.
QU-E4	Section 3.4 and Appendix B and C of the PRA Summary notebook (HC PSA-013) provide an evaluation of the important model uncertainties and Section 4.5 and Appendix E provide a set of structured sensitivity evaluations based on these uncertainties. Sensitivity calculations were run, with seven cases being identified as important to model uncertainty. Table 4.5-1 of the PSA-013 contains a summary of sensitivity cases to identify risk metric changes associated with candidate modeling uncertainties. The uncertainties are identified based on generic sources of uncertainty provided in EPRI TR-10009652. However, no additional plant-specific sources of uncertainty are addressed. Initial clarification on sources of uncertainty was provided in a July 27, 2007 NRC memorandum, which specified that at a minimum for a base PRA the analyst must "identify the assumptions related to PRA scope and level of detail, and characterize the sources of model uncertainty and related assumptions, i.e., identify what in the PRA model could be impacted and how". In addition, "While an evaluation of any source of model uncertainty or related assumption is not needed for the base PRA, the various sources of model uncertainty and related assumptions do need to be characterized so that they can be addressed in the context of an application. Therefore, the search for candidates needs to be fairly complete (regardless of capability category), because it is not known, a priori, which of the sources of model uncertainty or related	IE-D3,AS-C3,SC-C3,SY-C3,HR-I3,DA-E3,IF-F3,LE-F2/G4	The peer review found that the QU-E4 Supporting Requirements met Capability Category II. The finding relates to whether all of NUREG-1855 and its companion EPRI document has been fully implemented. As part of the EDG AOT extension application, NUREG-1855 and the companion EPRI document were reviewed and the guidance implemented to assess the modeling uncertianty. See Appendix B of this report.

Table 4.1-1

GAPS TO CAPABILITY CATEGORY II OF THE ASME PRA STANDARD

Applicable SRs	Description of Gap	Related SRs	Importance to Application
	assumptions could affect an application." So excluding plant-specific sources of uncertainty from characterization because they did not "rise to the level that they would be considered candidates for modeling uncertainty" is not appropriate. FINDING - The information provided is incomplete; the most recent industry guidance to address modeling uncertainty in order to meet Cat II for these SRs is not met.		
SY-A6	System components and boundaries are typically not defined in the system notebooks but referred to the Component Data Notebook. This is acceptable for components but the system boundaries should be defined in the system notebook. FINDING - The information provided is incomplete such that the SR is not met.	SY-A3	This is a documentation issue not affecting the ability to perform the EDG AOT extension risk assessment. As noted in the finding, the component information is present in the documentation of the Component Data Notebook. In addition, the system boundary has been drafted for each system notebook but not yet included in the published system notebooks. A review of these system boundaries reveals no impact on the EDG AOT extension risk assessment.

Table 4.1-1

GAPS TO CAPABILITY CATEGORY II OF THE ASME PRA STANDARD

Applicable SRs	Description of Gap	Related SRs	Importance to Application
SY-C2	The documentation present in the system notebooks largely addresses the suggested topics from this SR. However, there are several recommendations for improving the documentation: 1. Section 4.4, Dependency Matrix, should have a legend detailing what A and B represent, this was seen in the CRD notebook. 2. Section 2.10 has generic spatial dependencies for CRD. For CS it states "No spatial dependencies other than those imposed by room cooling, internal flooding, and LOCA harsh environment." No details are provided. No details are provided on room location for the CRD and CS notebooks. 3. System walkdown checklist should be used to address the topics in SY-C2. There are system walkdown checklists for the flooding but the questions and focus is not the same as required in SY-C2. 4. If only going to list the basic events in the Quantification Notebook there should be a tie in each System notebook going to the respective systems. FINDING - The information provided is incomplete such that the SR is not fully met; the information provided must be more readily defensible and traceable. It is noted that both SRs SY-C2 and SY-A14 meet Capability Category II. However, given that F&O SY-C2-01 is categorized as a Finding, these SRs are retained for further evaluation.	SY-A14	The Supporting Requirement SY-C2 met Capability Category II in the peer review assessment, however, a finding was identified. This is a documentation finding not affecting the ability to perform the EDG AOT extension risk assessment. A review of each specific item in the finding relative to the EDG AOT extension risk assessment was performed. It revealed no impact on the risk assessment for this application.

The "Facts and Observations" for Hope Creek have been evaluated and addressed by the Hope Creek PRA Program as part of the 2003 and 2008 PRA updates. There were no "A" Facts and Observations and 84 "B" Facts and Observations identified in the 1999 PRA Peer Review report. All 84 Facts and Observations have been resolved by model changes in the 2003 update. No outstanding "A" or "B" priority F&Os remain from the 1999 BWROG Certification peer review.

4.1.4.2 ASME PRA Standard PRA Peer Review

Consistent with the ASME PRA Standard as endorsed by RG 1.200 Rev. 1, PSEG in 2008 updated the PRA to meet Capability Category II. In addition, in October 2008 a PRA peer review of the 2008 PRA model was performed.

The results of this peer review superceded the 1999 BWROG peer review. The conclusion of the Hope Creek PRA Peer Review was positive, and the PRA Peer Review Team stated that the Hope Creek PRA can be effectively used to support applications involving risk-informed applications.

Subsequent to the ASME PRA peer review, the HCGS 2008 PRA model and documentation were updated to address most of the findings and the Supporting Requirements that did not meet Capability Category II.

Table 4.1-1 summarizes those Supporting Requirements that have not been fully met at Capability Category II (DA-D1, SY-A6) or have residual unresolved findings (QU-E4, SY-C2).

4.1.5 Consistency with ASME PRA Standard: PRA Self-Assessment Analysis and Peer Review

In addition to the formal peer review process performed in 2008 and following the issuance of the ASME PRA Standard and its endorsement by the NRC in RG 1.200, PSEG undertook a detailed review of the Hope Creek PRA model and documentation.

This review was performed using the NEI recommended self-assessment process as endorsed by the NRC in RG 1.200. The objective of the Hope Creek self-assessment is to identify gaps in the PRA with respect to Capability Category II for all supporting requirements.

The HCGS PRA Update process includes the self-assessment of the 2008 PRA model (HC108B), data, and documentation using the ASME PRA Standard as endorsed by RG 1.200 (Rev. 1). These self-assessment identified items were then resolved as part of the update process.

The Hope Creek PRA meets or exceeds Capability Category II for all of the SRs over all of the PRA elements with the exceptions noted in Table 4.1-1. If a Capability Category II is required for each SR, the SRs found to require some enhancements over those currently included in the Hope Creek PRA models or documentation are identified in Table 4.1-1. These SRs are identified in Table 4.1-1 by the PRA element and the specific ASME SR along with the effect of these SRs on the EDG extended AOT application.

There are 311 Technical Supporting Requirements plus 10 Maintenance and Update Supporting Requirements.

There are two Supporting Requirements (DA-D1, SY-A6) that did not meet Capability Category II. In addition, a review of the results of the self-assessment finds that the EDG AOT extension is not affected by the status of these two supporting requirements or the findings associated with QU-E4 and SY-C2.

4.1.6 URE Status

The URE (Update Requirement Evaluation) database is a resource and working tool used by the Risk Management Team to ensure that the as-built, as-operated HCGS plant configuration is reflected in the PRA. In addition, enhancements to the PRA quality are also identified, tracked, and resolved. The observations are recorded in the URE database. These observations identify potential areas of investigation for future model enhancement.

The EDG AOT Extension Application Model has included resolution of all of the UREs that may significantly affect the calculated risk metrics.

4.2 CONCLUSION

The culmination of the internal events and internal flood PRA development process, the associated PRA peer reviews, and the self-assessments is the current 2008 Model of Record (MOR).

No vulnerabilities have been uncovered; however, the revisions have allowed the use of the PRA to provide a better risk characterization of systems, structures, and components for applications by incorporating into the model plant specific data, the latest procedures, and the current plant hardware modifications. These applications include the following:

- Prioritization of testing of MOVs for GL 89-10
- Prioritization of testing of AOVs for GL 89-10
- Risk significance for the Maintenance Rule
- On-line maintenance risk assessment
- Severe Accident Mitigation Alternatives (SAMA) in support of Life Extension
- Extended Power Uprate (EPU)
- Containment Integrated Leak Rate Test (ILRT) interval extension
- MSPI

- RI-ISI
- Other risk ranking processes (e.g., CDBI)
- EDG Allowed Outage Time Extension

4.3 EXTERNAL EVENTS CONSIDERATIONS

4.3.1 Overview

External hazards were evaluated in the Hope Creek Individual Plant Examination for External Events (IPEEE) submittal in response to the NRC IPEEE Program (Generic Letter 88-20 Supplement 4) [17]. The IPEEE Program was a one-time review of external hazard risk and was limited in its purpose to the identification of potential plant vulnerabilities and the understanding of associated severe accident risks.

The results of the Hope Creek IPEEE study are documented in the Hope Creek IPEEE [18]. Each of the Hope Creek external event evaluations were reviewed as part of the Submittal by the NRC and compared to the requirements of NUREG-1407 [19]. The NRC transmitted to PSEG in 1999 their Staff Evaluation Report of the Hope Creek IPEEE Submittal [20].

Consistent with Generic Letter 88-20, the Hope Creek IPEEE Submittal does not screen out seismic or fire hazards, but provides quantitative analyses.

The following is a brief summary of the seismic and fire hazards probabilistic analysis. In addition, Appendix A provides a more detailed discussion of the external hazards analysis treatment.

4.3.2 Seismic PRA

The seismic risk analysis provided in the Hope Creek Individual Plant Examination for External Events is based on a detailed Seismic Probabilistic Risk Assessment.

The Hope Creek Seismic PRA study is a detailed analysis that, like the internal fire analysis, uses quantification and model elements (e.g., system fault trees, event tree structures, random failure rates, common cause failures, etc.) consistent with those employed in the internal events portion of the Hope Creek PRA.

The Hope Creek IPEEE Seismic PRA was developed using a process as described in the IPEEE submittal and summarized below:

- Seismic hazard analysis
- Seismic fragility assessment
- Seismic systems analysis
- Quantification of Seismic CDF

Some of the highlights of the Hope Creek Seismic PRA methodology include the following:

- Seismic hazard curve is based on the EPRI site specific seismic hazard study. In addition, revised Lawrence Livermore National Laboratory (LLNL) seismic hazard estimates are used as input as a sensitivity case.
- A seismic event is not assumed to result in a Loss of Offsite Power (LOOP). Seismic failure of offsite power is evaluated on a probabilistic basis according to component fragilities.

The Hope Creek IPEEE states that no plant unique or new vulnerabilities associated with the Seismic Analysis were identified. As identified above, the seismic PRA is currently maintained for Hope Creek using the original IPEEE hazard curve and identified dependencies and fragilities. Thus, quantitative insights can be derived based on the seismic PRA or a qualitative assessment can be performed.

The seismic analysis for Hope Creek is included in the quantification. The particular application which is the subject of this analysis involves the extended EDG AOT for the A and B EDGs. The significant insight regarding the seismic contribution for this application is that similar pieces of equipment at similar locations within the plant are subject to a high failure probability correlation due to a seismic hazard. Therefore, a seismic event that fails one diesel generator is modeled to also fail the second diesel generator because of high correlation between seismic failures. This seismic hazard correlation effect minimizes the effect of the diesel generator AOT extension on the calculated risk metrics.

The only residual seismic effect on CDF is when the seismic event causes a loss of offsite AC power. This results in the challenge to the diesel generators. As can be seen from the quantitative results the seismic contribution due to these seismic initiators is quite small.

4.3.3 Fire PRA

The internal fire events were addressed by using a combination of the Fire Induced Vulnerability Evaluation (FIVE) methodology [21] and industry accepted Fire PRA techniques in NUREG/CR-2300 and NUREG/CR-4840. The Hope Creek Fire PRA study is a detailed analysis that, like the seismic analysis, uses quantification and model elements (e.g., system fault trees, event tree structures, random failure rates, common cause failures, etc.) consistent with those employed in the internal events portion of the Hope Creek PRA.

The Hope Creek IPEEE Fire PRA was developed using a multi-step process as described in the IPEEE submittal and summarized below:

- Step 1 – Fire compartment interaction analysis
- Step 2 – FIVE methodology quantitative screening
- Step 3 -- Develop fire PRA analysis in accordance with NUREG/CR-2300 and NUREG/CR-4840

Some of the highlights of the Hope Creek Fire IPEEE methodology include the following:

- Fire initiation frequencies based on the FIVE methodology.
- High hazard rooms (those that contain a large amount of combustibles) were specifically analyzed.

The Hope Creek IPEEE states that no fire induced vulnerabilities were identified as a result of the analysis. The IPEEE also states that the NRC Fire Risk Scoping Study safety Issues were addressed during the fire analysis and it was found that each of the issues has been adequately addressed at Hope Creek. Quantitative insights can be derived based on the IPEEE fire PRA or a qualitative assessment can be performed.

The fire PRA hazard quantification for the EDG AOT extension includes the following revisions:

- Updated fire initiating event frequencies
- Updated modeling to reduce some excess conservatisms

See Appendix A for a discussion of the Fire PRA.

4.3.4 Other External Hazards

In addition to internal fires and seismic events, the Hope Creek IPEEE analysis of high winds or tornados, external floods, transportation accidents, nearby facility accidents, release of onsite chemicals, detritus and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards.

The other external hazards are assessed to be non-significant contributors to plant risk based on analysis that is briefly summarized in Appendix A.

4.3.5 External Hazard PRA Summary

As part of each PRA update since 2003, the seismic and fire PRA models have been incorporated directly into the model used for the full power internal events PRA. This allows all fire and seismic initiating events to be quantified using the latest internal events fault trees and accident sequences with the external event initiators failing the appropriate systems, functions, and crew response actions.[(1)]

The use of these external event quantitative models is judged to provide reasonable evaluations of the quantitative contribution to the risk metrics associated with the EDG AOT extension risk assessment.

4.4 SUMMARY

The Hope Creek PRA maintenance and update processes and technical capability evaluations described above provide a robust basis for concluding that the PRA is suitable for use in risk-informed processes.

(1) For many PRA applications (e.g., online maintenance), the fire and seismic initiating event frequencies are set to 0.0 in order to preclude quantification of the external event risk contributors with the internal events results.

Section 5

UNCERTAINTY ASSESSMENT USING SENSITIVITY EVALUATIONS

5.1 OVERVIEW

The NRC in NUREG-1855 describes a process for the evaluation of uncertainties for PRA applications.

The NUREG-1855 process involves a multi-step process for the identification, screening, and detailed assessment of uncertainties. Appendices B and F outline the NUREG-1855 process and the identification of candidate uncertainties to undergo sensitivity evaluation. This detailed assessment takes the form of sensitivity calculations that provide input to the decision makers.

The risk metric parameters chosen to provide the comparison among the sensitivity cases and with the EDG AOT Extension Application Model base case are the following:

- ΔCDF_{AVE} (change in Core Damage Frequency after Extended AOT implementation)
- ICCDP (Incremental Conditional Core Damage Probability)
- $\Delta LERF_{AVE}$ (change in Large Early Release Frequency after Extended AOT implementation)
- ICLERP (Incremental Conditional Large Early Release Probability)

One of the methods to provide valuable input into the decision making process is to provide specific point estimate calculations for situations with different assumed conditions. This section describes the following:

- The sensitivity cases that have been identified
- The process used for the sensitivity evaluation
- The results of the sensitivity evaluations

5.2 IDENTIFICATION OF SENSITIVITY CASES TO SUPPORT DECISION MAKING

The identification of useful sensitivities involves identifying potential issues that have large uncertainty or may change based on future plant operation and should be considered by the decision makers. These sensitivities fall into the following general areas:

A. Model or data assumptions
B. Specific equipment performance issues
C. Operating philosophy changes
D. Plant Modifications

The following are the items identified for each general area. Appendices B and F provide the derivation of these uncertainties to be considered explicitly.

A. <u>Model or Data Assumptions</u>

The following model or data assumptions could be important in the decision making process and are identified as candidates for a sensitivity evaluation:

- LOOP Initiating Event Frequency
- EDG Failure To Start And Failure To Run Probabilities
- Fire Ignition Frequencies
- Portable Generator Alignment Probability
- Seismic Hazard Curve
- HPCI Reliability

B. <u>Specific Equipment Performance Issues</u>

The specific performance issues that could modify the PRA results were derived from a review of Maintenance Rule data. This data indicate that no equipment is identified as requiring special sensitivity to provide input to the decision making process.

C. Operating Philosophy Changes

Operating philosophy, procedures, and training can substantially change the risk profile. The following specific items are identified that may influence the decision making process:

- EDG unavailability given AOT is extended
- EDG in the same mechanical division is available if an EDG is taken OOS for Extended AOT
- Operator actions and their assessment

D. Plant Modifications

The following plant modifications are identified for consideration and sensitivity cases developed to show their impact.

- The elimination of the Salem 3 Gas Turbine is included in this application specific model base case.

No other plant modifications or procedure changes lead to model uncertainties or changes that affect this application.

5.3 PROCESS FOR SENSITIVITY EVALUATION

The process for evaluating the sensitivities is straightforward to perform.

The initial process involves identifying the largest impact that can be reasonably postulated on individual inputs to the risk assessment (i.e., usually the 95% upper bound). Then, the Hope Creek EDG AOT Extension Application Model is quantified to ascertain the impact of such an assumption on the risk metrics chosen in RG 1.177 and 1.174.

In cases where the acceptance guidelines continue to be met, it is judged that the associated uncertainty is acceptable, and that it does not provide any additional impetus to decision makers to make further changes or introduce supplementary compensatory measures.

In cases where the acceptance guidelines are exceeded, the risk analyst evaluates whether there is a more reasonable uncertainty range that better represents the variation in the input parameters. Following this assessment by the risk analyst, the more reasonable range of the uncertainty is reflected in the sensitivity evaluation.

If the more reasonable sensitivity evaluation also leads to exceeding the acceptance guideline, the decision makers are to decide if the uncertainty presents a unique perspective that would require some different actions to compensate for this uncertainty. Subsection 5.4 provides the results of implementing this process.

5.4 SENSITIVITY RESULTS

A set of sensitivity cases including the Compensatory Measures 3 through 6 identified in Section 3 are reported in this section. For convenience, the sensitivity cases using the upper bound characterization of the input variable are summarized in Table 5-1. These sensitivity cases are reported in detail in Appendix B. (See Appendices B.3.1 through B.3.7.)

For the purposes of Table 5-1, the ICCDP and ICLERP are presented for the EDG "B" out of service (OOS). This is because the EDG "A" risk metrics are not as limiting as the EDG "B" risk metrics.

As noted by NUREG-1855, the use of these initial screening sensitivities may lead to exceeding the acceptance guidelines. Table 5-1 identifies several of the sensitivity cases that have one or more of the acceptance guidelines exceeded (refer to the shaded boxes in Table 5-1). It is not the intent of this process to say that the results of any one or more sensitivity cases being above the acceptance guidelines should automatically lead to a negative outcome by the decision maker. This initial scoping of the sensitivity cases identifies those cases that require more reasonable estimates of the uncertainty bounds.

Following the NUREG-1855 uncertainty assessment process, it is then incumbent upon the risk analyst to assess a more reasonable characterization of the uncertainty in the input variable. This additional intelligence is necessary to more accurately provide decision makers input based on reasonable alternate hypotheses rather than extreme tails of distributions.

From Table 5-1, the following sensitivities based on upper bound characterization of input variables result in exceeding one or more of the RG acceptance guidelines:

- Fire Initiating Event Frequencies (ICCDP)
- LOOP Initiating Event Frequency (ICCDP and ICLERP)
- HEP quantification (ICCDP and ICLERP)
- EDG Failure to Run and Failure to Start Probabilities (ICLERP)

The following specific qualitative insights from the Risk Management Team form the basis for a more reasonable upper uncertainty band and may be more useful for decision makers in assessing the sensitivity cases:

- Fire Ignition Frequency:
  - Higher fire ignition frequencies are not considered representative of trends at nuclear plants.
  - The extreme fire ignition frequencies are judged to be unrealistically high.
  - More reasonable changes in fire ignition frequencies are selected as appropriate to demonstrate expected variations in fire ignition frequencies.
- LOOP Initiating Event Frequency:
  - The upper bound LOOP initiating event frequency used in the Table 5-1 sensitivity case is judged to be significantly higher than can be anticipated for Hope Creek. In addition, one of the compensatory

measures addresses the severe weather portion of the LOOP frequency.

- A significant increase in LOOP frequency is used, but it is less than the extreme value postulated by the 95% upper bound.

- HEPs:
  - One purpose of the HEP sensitivity is to confirm that a systematic bias in the HRA process is not suppressing an important insight; that is the purpose of setting all of the HEPs to the 95th percentile value at the same time is to see if some additional actions should be separately identified as important.

    The conclusion for the EDG AOT extension sensitivity case is that an examination of the important contributors from the sensitivity case did not identify any new insights or indicate that there are any additional compensatory measures that should be considered.

- EDG Unreliability:
  - There is no evidence of degraded EDG performance at Hope Creek.
  - The extended AOT is proposed to <u>improve</u> EDG reliability. Therefore, the upper bound sensitivity case is not considered appropriate.
  - A more reasonable assessment of the EDG reliability is used.

Therefore, following the guidance in Section 5 of NUREG-1855, it is incumbent upon the analyst to characterize the degree of confidence in the assumptions associated with the sources of uncertainty listed above that lead to the base case results (with compensatory measures incorporated) being within the acceptance guidelines. It is not the intent of this process to say that the results of any one or more sensitivity cases being above the acceptance guidelines should automatically lead to a negative outcome by the decision maker. On the contrary, the intent of the process is to clearly identify those sources of uncertainty that are key to the decision (and therefore by definition will challenge the acceptance guidelines), and that appropriate compensatory measures have been identified to implement or otherwise deal with the key sources of uncertainty.

These assessments of the modeling sensitivity cases have led to defining more reasonable variations in the input parameters to provide appropriate inputs to decision makers. Appendix B.4 provides the details of these more reasonable sensitivity cases.

The more reasonable inputs to the sensitivity analysis results in the calculated risk metrics provided in Table 5-2. These inputs depend on the analysts' insights into the model, the plant, and the nature of the uncertainties. Table 5-2 includes inputs for modeling uncertainty that use reasonable estimates of the upper bound uncertainty unless the 95% upper bound does not result in exceeding the risk metric acceptance guideline.

The realistic sensitivity analyses for these modeling issues yield results that are within the acceptance guidelines for each of the sensitivity cases. This step is consistent with Section 5 of NUREG-1855 in that it provides the decision makers with reasonable assessments of the modeling uncertainty.

Table 5-1

SENSITIVITY CASE RESULTS USING 95% UPPER BOUND CHARACTERIZATION

Sensitivity Case	Description	Change in Model	ΔCDF_{AVE} (/yr)	$\Delta LERF_{AVE}$ (/yr)	ICCDP[1]	ICLERP[1]
-	Base Case	---	1.94E-07	1.81E-08	2.72E-07	3.49E-08
1	Use of LLNL Seismic Hazard	Modified Seismic IE	2.8E-07	1.82E-08	3.61E-07	3.49E-08
2	Use of More Conservative Fire Initiating Event Frequency	Modify Fire IE	8.20E-07	3.04E-08	7.10E-07[5]	4.87E-08
3	LOOP Initiating Event Frequency	Modify LOOP IE	6.12E-07	5.39E-08	8.44E-07[2]	1.04E-07[2]
4	EDG Unavailability Sensitivity	Add EDG AOT to Historical Data	2.06E-07	1.76E-08	2.72E-07	3.49E-08
5	Post-Initiator HEPs set at 95% Upper Bound	Modify all Post-Initiator HEPs	4.34E-07	6.56E-08	5.79E-07[3]	8.36E-08[3]
6	Diesel Generator Failure Rate set at 95% Upper Bound	Modify FTS and FTR for EDG	2.74E-07	2.60E-08	4.07E-07	5.06E-08[4]
7	Portable DC Generator Alignment	Modify Alignment HEP for Generator	2.70E-07	1.86E-08	3.84E-07	3.59E-08
8	HPCI Reliability	Modify HPCI TDP FTS	2.30E-07	2.52E-08	3.45E-07	4.86E-08

(1) For the purposes of this summary table, the ICCDP and ICLERP are presented for the EDG "B" out of service (OOS). This is because the EDG "A" risk metrics are not as limiting as the EDG "B" risk metrics.
(2) Extreme Initiating Event frequencies could lead to exceeding the mean estimate acceptance guideline for ICCDP and ICLERP.
(3) Extreme 95% upper bound HEPs lead to exceeding the acceptance guideline for the mean results.
(4) Extreme 95% upper bound estimates on EDG unreliability leads to exceeding the mean estimate acceptance guidelines for ICLERP.
(5) Higher Fire Ignition frequencies lead to one of the mean estimate acceptance guidelines being exceeded (ICCDP).

Table 5-2

SENSITIVITY CASE RESULTS USING REASONABLE UPPER BOUND CHARACTERIZATION OF MODELING UNCERTAINTIES[1]

Sensitivity Case	Description	Change in Model	ΔCDF_{AVE} (/yr)	$\Delta LERF_{AVE}$ (/yr)	ICCDP[2]	ICLERP[2]
-	Base Case	---	1.94E-07	1.81E-08	2.72E-07	3.49E-08
1	Use of LLNL Seismic Hazard	Modified Seismic IE	2.8E-07	1.82E-08	3.61E-07	3.49E-08
2	Use of Reasonable Upper Bound Fire Initiating Event Frequencies	Modify Fire IE	3.18E-07	1.97E-08	3.87E-07	3.73E-08
3	LOOP Initiating Event Frequency at Reasonable Upper Bound	Modify LOOP IE	2.72E-07	2.51E-08	3.80E-07	4.82E-08
4	EDG Unavailability Sensitivity at 95% Upper Bound	Add EDG AOT to Historical Data	2.06E-07	1.76E-08	2.72E-07	3.49E-08
5	Post-Initiator HEPs set at Reasonable Upper Bound	Modify all Post-Initiator HEPs	4.12E-07	2.05E-08	4.99E-07	3.85E-08
6	Diesel Generator Failure Rate set at Reasonable Upper Bound	Modify FTS and FTR for EDG	1.96E-07	1.25E-08	2.76E-07	2.41E-08
7	Portable DC Generator Alignment at 95% Upper Bound	Modify Alignment HEP for Generator	2.70E-07	1.86E-08	3.84E-07	3.59E-08
8	HPCI Reliability	Modify HPCI TDP FTS	2.30E-07	2.52E-08	3.45E-07	4.86E-08

(1) Table 5-2 includes inputs for modeling uncertainty that use reasonable estimates of the upper bound uncertainty unless the 95% upper bound does not result in exceeding the risk metric acceptance guideline.

(2) For the purposes of this summary table, the ICCDP and ICLERP are presented for the EDG "B" out of service (OOS). This is because the EDG "A" risk metrics are not as limiting as the EDG "B" risk metrics.

Section 6
SUMMARY AND CONCLUSIONS

Consistent with the NRC's approach to risk-informed regulation, PSEG has identified a particular Technical Specification requirement that is restrictive in its nature and, if relaxed, has a minimal impact on the safety of the plant. This Technical Specification is the requirement for the Emergency Diesel Generator (EDG) Allowed Outage Time (AOT) to be restricted to 72 hours for the A and B EDGs. The proposed change is to increase the Diesel Generator Allowed Outage Time, or as sometimes called the Completion Time (CT), from the currently specified 72 hours to 14 days[(1)].

This section summarizes the risk metrics requested by the NRC Regulatory Guides, provides the calculated results from the Hope Creek PRA model, and the conclusion from the assessment of the incremental risk change.

6.1 REGULATORY GUIDELINES

As described earlier, the probabilistic risk assessment input to the decision making process has been defined in detail by the NRC in two Regulatory Guides, Regulatory Guides 1.174 and 1.177.

The NRC has specified in Regulatory Guides the risk metrics that should be calculated to provide input into the decision making process. The risk metrics chosen by the NRC in their Regulatory Guides include the following:

- The change in Core Damage Frequency (CDF) (Reg. Guide 1.174)
- The change in Large Early Release Frequency (LERF) (Reg. Guide 1.174)
- The Incremental Conditional Core Damage Probability (ICCDP) (Reg. Guide 1.177)

(1) The NRC has previously issued an SER to allow the Hope Creek C and D EDGs to extend their AOT from 72 hours to 14 days.

- The Incremental Conditional Large Early Release Probability (ICLERP) (Reg. Guide 1.177)

These risk metrics are all calculated with the Hope Creek PRA EDG AOT Extension Application model which includes:

- Internal and External hazards
- Peer Review comments that affect the EDG AOT application
- Anticipated plant change to remove the Salem 3 Gas Turbine
- All diesel and proceduralized electrical cross ties accounted for in the model.

Quantitative guidelines are defined by the NRC in RG 1.174 and 1.177 for what is an acceptably small change in risk.[(1)] [(2)]

- The Hope Creek calculated ICCDP and ICLERP for each EDG are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Reg. Guide 1.177 for the increased EDG Allowed Outage Time have been met.
- Furthermore, the evaluation of changes in CDF and LERF due to the expected increased EDG unavailability, as mitigated by the compensatory measures listed in Section 3.3, have been shown to meet the risk significance criteria of Regulatory Guide 1.174 with substantial margin.

These calculations support the increase in EDG Allowed Outage Time (AOT) from a quantitative risk-informed perspective.

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(1) The guidelines given in Regulatory Guide 1.177 include:

> The licensee has demonstrated that the TS AOT change has only a small quantitative impact on plant risk. An ICCDP of less than 5.0E-7 is considered small for a single TS AOT change. An ICLERP of 5.0E-8 or less is also considered small.

(2) The guidelines from Regulatory Guide 1.174 are provided to assure that the CDF and LERF changes when the extended AOT is implemented remain acceptable. These guidelines specify acceptably small changes as a function of the absolute values of the CDF and LERF.

See Section 6.3 for a tabular comparison.

6.2 PRA MODEL

The quantitative evaluation of the risk metrics for this application is performed using the Hope Creek PRA EDG AOT Extension Application Model. This includes the following:

- The latest internal events and internal flood PRA model[(1)] which has also been peer reviewed against the ASME PRA Standard as endorsed by RG 1.200 Rev. 1.
- The fire PRA model developed from the IPEEE fire model using the latest system models and accident sequences plus more recent fire initiating event frequencies from the NRC (circa 2003).
- The seismic PRA model developed from the IPEEE seismic model using the latest system models and accident sequences.
- In addition, "other external events" have been reviewed for this application and screened out of the quantitative analysis.

6.3 QUANTITATIVE PRA RESULTS: REGULATORY GUIDE 1.177 AND 1.174

This subsection includes the quantitative PRA results using the Hope Creek PRA EDG AOT Extension Application Model.

The calculated results for the PRA model that includes both internal and external events with compensatory measures included are shown in Table 6.3-1. The results are shown for the case when compensatory measures are incorporated into the Hope Creek planning process.

(1) The application specific model has removed credit for the Salem 3 Gas Turbine because this may not be available in the future.

Compensatory measures are judged prudent to provide margin for the ICCDP and ICLERP to account for possible uncertainties in the quantitative calculations. The compensatory measures adopted for the EDG A and B extended AOT are equivalent to those adopted for the EDG C and D extended AOT. This makes plant procedures, training, and operations consistent across all four EDGs. Table 6.3-2 summarizes these compensatory measures.

The results in Table 6.3-1 are compared with the acceptance guidelines that are specified by the NRC in RG 1.174 and RG 1.177.

It is noted that for the case where the Compensatory Measures 3 through 6 are implemented, all of the risk metrics are well below the acceptance guidelines. (Compensatory Measures 1 and 2 provide qualitative philosophical approaches which are more difficult to translate into quantitative predictions of PRA changes.)

These results provide a good indication that the risk associated with this proposed extension of the EDG AOT is very small. These results are confirmed and maintained by the Tier 2 and Tier 3 analysis results and programmatic implementation.

In addition, the comparisons of the CDF and LERF risk metrics with the Reg. Guide 1.174 guidelines are shown in Figures 6.3-1 and 6.3-2, respectively.

6.4 OTHER CONSIDERATIONS

Attendant Shutdown Risk reductions associated with removing EDG Preventive Maintenance (PM) from refueling outages have not been quantified as part of this evaluation. The removal of EDG PMs from refuel outages is expected to further reduce the incremental risk associated with extending the AOT for EDG A and B.

In addition, a Configuration Risk Management Program (CRMP) will ensure that the plant state is monitored to minimize the risk impact of the change.

The Hope Creek fire and seismic hazard analysis is probabilistically evaluated to provide insights regarding the focused EDG AOT application. Both the fire and seismic probabilistic models are derived from the IPEEE models. These models reside within an integrated application specific model. It is recognized that these fire and seismic probabilistic models do not meet current PRA standards. The purpose of using these models is two-fold:

- Demonstrate that the quantitative impact on the risk metric calculations is small
- Identify the critical insights that may arise from the consideration of these hazards

Both of these objectives are met in the EDG AOT evaluation. In addition, sensitivity cases are implemented to demonstrate possible variations in the results due to modeling assumptions in these external hazard probabilistic models.

The quantitative results from the integrated assessment of internal and external events is also interpreted qualitatively to confirm that the results are consistent with the plant design and that the resulting cutsets are appropriate.

This approach is judged more useful than a strictly qualitative approach to the assessment of fire and seismic risk impacts on the EDG AOT application.

6.5 UNCERTAINTIES

In addition to the assessment of the mean risk metrics which are specified in RG 1.177 and 1.174 for comparison with the acceptance guidelines, it is also prudent to examine whether modeling uncertainties may distort these comparisons.

Therefore, an extensive review of potential modeling uncertainties that may impact the risk metrics is performed. To this end, NUREG-1855 and the companion EPRI guidelines on the treatment of uncertainties are used. Section 5 and Appendices B and F provide various perspectives on the identification and disposition of various uncertainties. Section 5 provides a summary for input to the decision makers.

Uncertainties are minimized by the use of the Compensatory Measures.

6.6 CONCLUSION

The risk change calculated with the Hope Creek PRA for the proposed EDG AOT extension for the A and B diesel generators is very small.

The ICCDP and ICLERP for each EDG are sufficiently below the guidelines of < 5.0E-07 and < 5.0E-08, respectively, to be able to call the risk change small. Hence, the guidelines of Reg. Guide 1.177 for the increased EDG Allowed Outage Time have been met.

Furthermore, the calculated of changes in CDF and LERF due to the extension of the EDG A and B AOT, as mitigated by the compensatory measures listed in Section 3.3, have been shown to meet the risk significance criteria of Regulatory Guide 1.174 with substantial margin, i.e., Region III which represents "very small risk changes".

These calculations support the increase in EDG Allowed Outage Time from a quantitative risk-informed perspective so long as the plant operational and maintenance practices are in reasonable agreement with the assumptions made in this evaluation.

Table 6.3-1

RESULTS OF RISK ASSESSMENT FOR HOPE CREEK WITH COMPENSATORY MEASURES INCLUDED[3]

Risk Metric	Risk Metric Results	NRC Regulatory Guide Acceptance Guideline	Meets Acceptance Guideline
ΔCDF_{AVE} (/yr)	1.94E-07	< 1.0E-06[1]	Yes[1]
$\Delta LERF_{AVE}$ (/yr)	1.81E-08	< 1.0E-07[1]	Yes[1]
$ICCDP_{EDG\ A}$	9.96E-08	< 5.0E-07[2]	Yes
$ICLERP_{EDG\ A}$	<1.00E-10	< 5.0E-08[2]	Yes
$ICCDP_{EDGB}$	2.72E-07	< 5.0E-07[2]	Yes
$ICLERP_{EDGB}$	3.49E-08	< 5.0E-08[2]	Yes

(1) Region III of RG 1.174 -- very small risk changes.
(2) RG 1.177.
(3) Table 6.3-2 defines the Compensatory Measures.

Table 6.3-2

COMPENSATORY MEASURES FOR USE DURING EXTENDED EDG OUTAGES

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).
2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.
3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the associated mechanical division (A&C or B&D) must be capable, operable and available to mitigate the consequence of a LOOP condition.
4. The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.
5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.
6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

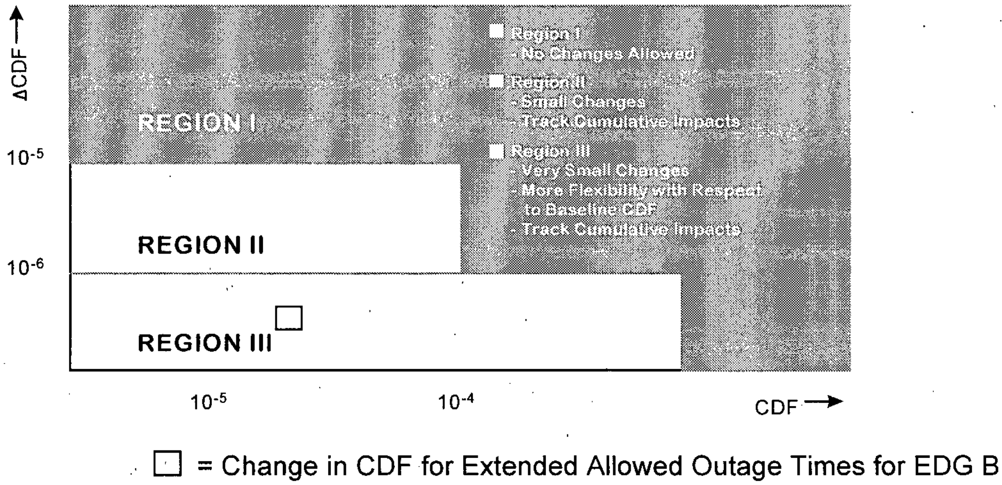

Figure 6.3-1 Acceptance Guidelines* for Core Damage Frequency (CDF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

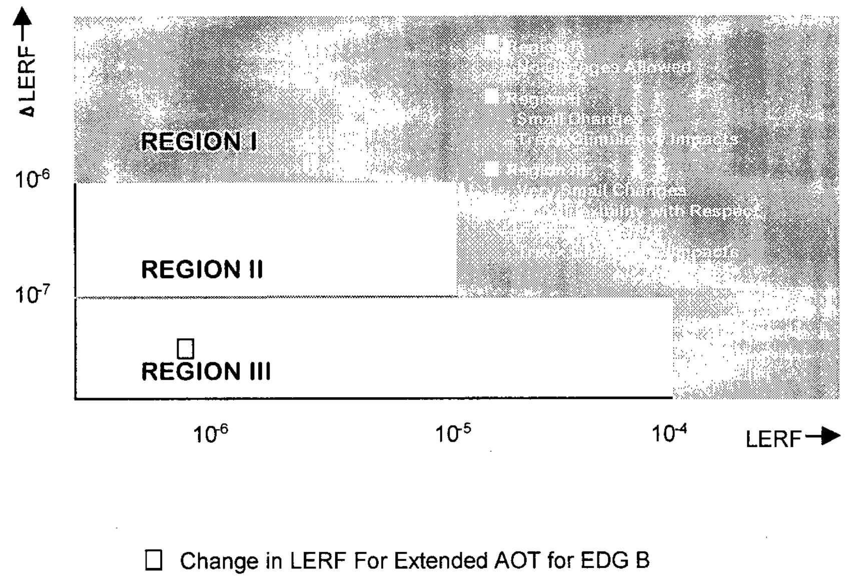

Figure 6.3-2 Acceptance Guidelines* for Large Early Release Frequency (LERF)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

Section 7
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Appendix A

EXTERNAL EVENTS ASSESSMENT

Appendix A
EXTERNAL EVENTS ASSESSMENT

A.1 INTRODUCTION

This appendix discusses the external events assessment in support of the Hope Creek EDG AOT extension risk assessment. It includes the following objectives:

- An examination of past Hope Creek external event analysis
- A reevaluation of that analysis to ensure it reflects the as-built, as-operated plant
- Incorporation of the analysis into a quantitative PRA model where appropriate because it may influence the Allowed Outage Time (AOT) probabilistic analysis;

  <u>or</u>

  Alternatively, a qualitative assessment to indicate the impact on the Allowed Outage Time assessment.

These objectives are reflected in the following subsections:

- Appendix A.2 describes the disposition of the external events regarding their quantification or screening
- Appendix A.3 describes the treatment of the quantified fire risk
- Appendix A.4 describes the treatment of the quantified seismic risk

A.2 ASSESSMENT OF RELEVANT HAZARD GROUPS

A.2.1 <u>Overview</u>

The purpose of this portion of the assessment is to screen the spectrum of external event challenges to determine which external event hazards should be explicitly addressed as part of the Hope Creek EDG AOT extension risk assessment.

The Hope Creek IPEEE [A-1] performed an examination of external event hazards to assess their potential for impacting the Hope Creek risk profile. Internal plant fires and seismic hazards were explicitly quantified in the IPEEE using conservative assessments of these hazards. Beginning with the list of external events found in NUREG/CR-2300, the class of external events termed "other external events" have been screened out either by compliance with the 1975 SRP criteria[(1)] or by bounding probabilistic analyses that demonstrate a core damage frequency of less than the IPEEE screening criterion. In addition to the quantification of internal fires and seismic events, the Hope Creek IPEEE [A-1] evaluated high winds and tornados, external floods, transportation and nearby facility accidents, release of on-site chemicals, and detritus.

No significant quantitative contribution from these external events was identified by the IPEEE evaluations. The compensatory actions and risk insights in this LAR are judged applicable to reduce the risk associated with these events.

A.2.2 Assessment for EDG AOT Extension

With an understanding of the role that the EDG system plays in mitigating risk, a confirmatory assessment of the relevant hazard groups can be completed for this particular application. Section 6.3.3 of NUREG-1855 [A-2] provides a list of hazard groups that should be considered in a risk assessment. Table A.2-1 summarizes how those hazard groups are dispositioned for Hope Creek for the EDG A and B AOT extension. The majority of the hazard groups are screened from consideration based on a review of the information provided in the Hope Creek IPEEE, using the screening approaches discussed in Section 6 of NUREG-1855.

The quantified at-power PRA models used for this analysis therefore include the following:

- Internal events

---

(1) The design of the Hope Creek plant facilities meets the NRC's 1975 Standard Review Plan criteria for each of the other external events evaluated.

- Internal floods
- Internal fires
- Seismic events

The other hazard groups are demonstrated not to be relevant based on a screening analysis as shown above. The at-power ΔCDF and ΔLERF for this application are such that the results lie in Region III of the RG 1.174 acceptance guidelines and therefore, it is unnecessary to evaluate the low-power and shutdown contribution to the base CDF and LERF. Furthermore, the change being proposed involves moving unavailability of the EDGs from shutdown to power conditions. Because a detailed low power and shutdown PRA model has not been developed for this plant, the analysis will conservatively omit this risk reduction, which could be used under RG 1.174 to offset the increase in at power risk in the ΔCDF and ΔLERF calculations.

<u>Conclusions of Screening Assessment</u>

Given the foregoing discussions, most of the external hazards are assessed to be negligible contributors to plant risk. Explicit treatment of these other external hazards is not necessary for most PRA applications (including the EDG AOT extension risk assessment) and would not provide additional risk-informed insights for decision making.

Further information is presented in this appendix to assess the risk associated with the internal fires and seismic hazard groups.

Table A.2-1

HAZARD GROUPS CONSIDERED IN THE RISK ASSESSMENT

Hazard Group	Approach	Basis
Internal Events Internal Floods	Addressed quantitatively.	Plant-specific PRA reflecting the as-built, as-operated plant is used to quantitatively estimate the risk impacts.
Internal Fires	Addressed quantitatively and qualitatively.	Plant-specific PRA utilized to quantitatively estimate the risk impacts. However, the use of this model is subject to limitations and precautions as described in Appendix A.3. More importantly, it was utilized to identify important fire areas for consideration of potential compensatory measures.
Seismic Events	Addressed using a conservative approach	Plant-specific PRA is utilized to quantitatively estimate the risk impacts. The contribution to the change in risk associated with the EDG OOS is shown to be minimal.
Accidental Aircraft Impacts	Screened from consideration based on low likelihood of threat-induced challenge.	Removal of an EDG may decrease reliability of AC power support, but per the IPEEE, the frequency of damage from accidental aircraft impacts is very small (<7E-8/yr) compared to other events already considered (e.g., non-recoverable LOOP)
External Floods	Screened from consideration based on SRP 1975 criteria, RG 1.59, and low likelihood of threat-induced challenge.	From the Hope Creek IPEEE, external floods were screened as a significant contributor per NUREG-1407. Since HCGS is an SRP plant it meets the requirements of Regulatory Guide 1.59. Additionally, external floods would be a slow developing event which would allow restoration of out of service EDG prior to presenting a significant challenge.

Table A.2-1

HAZARD GROUPS CONSIDERED IN THE RISK ASSESSMENT

Hazard Group	Approach	Basis
Extreme Winds and Tornados (including generated missiles)	Screened from consideration based on 1975 SRP criteria and the low frequency of the challenge.	From the Hope Creek IPEEE, high winds and tornados (including generated missiles) were screened as a significant contributor per NUREG-1407. The plant is designed for extreme winds and tornados. Removal of an EDG may decrease reliability of on-site AC power function, but the frequency of wind/tornado-induced damage is very small compared to other events with similar consequences already considered (e.g., non-recoverable LOOP)
Turbine-Generated Missiles	Screened from consideration based on low likelihood of threat-induced challenge	Turbine-generated missiles from Salem and HCGS were both screened out as potential significant contributors to risk in the HCGS IPEEE. Removal of an EDG may decrease reliability of on-site AC power function, but the frequency of turbine-generated missile-induced damage is very small compared to other events already considered with a similar consequence (e.g., non-recoverable LOOP)
External Fires	Screened from consideration based on low likelihood of threat-induced challenge	External fires are screened from consideration in the IPEEE since the site is cleared of forestry and external fires are unlikely to spread onsite. Additionally, the plant structures are designed for the effects of external fires (i.e., safety related structures are reinforced concrete). Removal of an EDG may decrease reliability of on-site AC power function, but the frequency of an external fire-induced challenge is very small compared to other events already considered (e.g., non-recoverable LOOP)

Table A.2-1

HAZARD GROUPS CONSIDERED IN THE RISK ASSESSMENT

Hazard Group	Approach	Basis
Accidents From Nearby Facilities	Screened from consideration based on limited role of EDGs in mitigating hazards from accidents at nearby facilities.	All activities and facilities within five miles fo the HCGS site are considered in the HCGS UFSAR. No significant manufacturing and chemical plants, oil refineries, storage facilities, military facilities, transportation routes other than the Delaware River are located within five miles of the HCGS site. Therefore, transportation and nearby industrial and military facility events have been screened out by the SRP criteria. EDGs are not a significant system in mitigating accidents from nearby facilities. The potential increase in risk impact is dominated by potential effects of toxic gases on operators. Operators are trained and periodically tested on their ability to put on a breathing apparatus after initiation of a toxic chemical alarm. If they succeed, there is no impact on the plant, and no need to employ EDGs.
Release of Chemicals Stored at the Site	Screened from consideration based on limited role of EDGs in mitigating hazards from accidents at nearby facilities.	Accidents involving release of on-site chemical storage do not pose a vulerability at HCGS owing to conformance to Regulatory Guide 1.78. EDGs are not significant in mitigating chemical releases. The potential increase in risk impact is dominated by potential effects of toxic gases on operators. Operators are trained and periodically tested on their ability to put on a breathing apparatus after initiation of a toxic chemical alarm. If they succeed, there is no impact on the plant, and no need to employ EDGs.

Table A.2-1

HAZARD GROUPS CONSIDERED IN THE RISK ASSESSMENT

Hazard Group	Approach	Basis
Transportation Accidents	Screened from consideration based on limited role of EDGs in mitigating hazards from accidents at nearby facilities.	EDGs are not significant in mitigating transportation accidents that lead to chemical releases. The potential increase in risk impact is dominated by potential effects of toxic gases on operators. Operators are trained and periodically tested on their ability to put on a breathing apparatus after initiation of a toxic chemical alarm. If they succeed, there is no impact on the plant, and no need to employ EDGs.
Transportation Accidents Pipeline Accidents (e.g., natural gas)	Explosive hazards screened on the basis of limited impact on the plant. Probabilistic hazard screening analyses were performed to screen out river explosions and ship impact on the Service Water Intake Structure. (The Service Water Intake Structure is designed for the design basis tornado.)	Since the HCGS plant is an SRP plant, the hazards associated with the river traffic are within the acceptable limits. River traffic has reduced substantially, since the plant was built. There is an indication that an average of 50 explosive carrying vessels (34 LPG and two solid explosive – with temporary increase to 12) have passed the HCGS site each year. However, given the fact that the shipping buoy is located over a mile away from the site and the explosion probability is low, the impact of explosive carrying vessels on the plant safety structures is not significant. Additionally, given that currently no facility along with the Delaware River is licensed to carry explosives, supports the conclusion that river traffic hazards do not reveal a vulernability at the HCGS site.

Table A.2-1

HAZARD GROUPS CONSIDERED IN THE RISK ASSESSMENT

Hazard Group	Approach	Basis
Detritus, which has been postulated to have the potential of affecting service water intake, was also evaluated by a screening analysis. It was found that a large perturbation in the river, such as an earthquake, could initiate a detritus event that might affect all service water intakes. The frequency of an earthquake induced detritus event was found to be below the IPEEE screening criterion	Detritus, which has been postulated to have the potential of affecting service water intake, was also evaluated by a screening analysis. It was found that a large perturbation in the river, such as an earthquake, could initiate a detritus event that might affect all service water intakes. The frequency of an earthquake induced detritus event was found to be below the IPEEE screening criterion	Screening calculations as part of IPEEE identified that Detritus impact on SW would be a low frequency.

A.3 INTERNAL FIRE PROBABILISTIC RISK ASSESSMENT

The internal fire probabilistic risk assessment is based on the latest HCGS internal event model (2008B) which incorporates the fire analysis developed as part of the IPEEE and updated in 2003. This section summarizes the IPEEE fire probabilistic risk assessment, assumptions and limitations, and results/insights related to the proposed EDG AOT extension.

A.3.1 Methodology

The technical basis of the HCGS fire IPEEE is a fire probabilistic risk assessment (PRA) performed in a manner consistent with the guidance in NUREG/CR-2300 and NUREG/CR-4840. The approach taken for the fire PRA was to perform a scenario-by scenario analysis of unscreened compartments accounting for the relative location of ignition sources and targets. Fire damage calculations were performed to determine the extent of potential damage from each postulated fire source. Openings in walls as well as open active fire dampers were included in the assessment of the extent of fire damage.

In addition to items requested in NUREG-1407, a special feature of the IPEEE analysis is an analysis of high hazard (which are not necessarily high risk) rooms at the HCGS. These are rooms which contain a somewhat larger amount of combustible materials (other than normal cables).

The PRA is preceded by 1) a fire compartment interaction analysis (FCIA) per FIVE guidance, and 2) a quantitative screening analysis also performed in a manner consistent with FIVE guidance. A qualitative screening analysis was not performed for the HCGS IPEEE; that is, no compartments were eliminated from quantitative consideration owing to qualitative factors alone.

Many fire compartments analyzed in this study consist of multiple rooms. The result of the FCIA was a total of 209 fire compartments which met the FIVE criteria. These compartments included the turbine building, reactor building, control/diesel building, radwaste building, service water intake structure, and transformer yard.

A screening process was implemented to avoid a detailed PRA on all of the 209 compartments identified from the Fire Compartment Interaction Analysis and the transformer array in the yard. The objective of the screening assessment was to reduce the number of compartments on which detailed fire risk assessments must be performed. A conservative, screening assessment of core damage frequency is used to achieve this objective.

Each of the unscreened compartments was subjected to a detailed scenario-by-scenario probabilistic analysis. A fire scenario is defined as a unique source, fire intensity, target, and initiating event combination. The total core damage frequency of each compartment was evaluated using a quadruple summation over fire sources, targets, intensities, and initiating events.

The PRA included treatment of "hot shorts", considered the potential for openings and failure of active fire barriers to create a path for propagation of damage, and included the potential for inadvertent safety relief valve opening and interfacing system LOCAs.

The Fire Risk Scoping Study Issues from the IPEEE were thoroughly treated by document reviews, seismic and fire walkdowns, system analyses of the potential for damage owing to inadvertent suppression system actuation, and the fire PRA.

A.3.2 Assumptions and Limitations

This section provides an overview of the general assumptions that form the basis of this analysis:

1. Room inventory is as deduced by a review of the UFSAR, MMIS lists, pre-fire plans and as witnessed during the walkdown.

2. Fire barriers for compartments defined for this analysis were defined in accordance with the EPRI FIVE Method, Paragraph 5.3.6.

3. The fire source (i.e., pump, cabinet, transformer, compressor, etc.) is completely disabled by the fire.

4. If two pumps or compressors (e.g., chillers) are located within close proximity, a fire in one is assumed to disable both.

5. Fire damage calculations were used to assess the spread of damage, owing to a hot gas layer, through openings in walls. In these calculations, all walls in the source room, below the level of the opening, were assumed to vanish.

6. All fire damage calculations assume cables are unprotected even if they are in conduit, protected by a cable tray bottom, or protected by an enclosed cable tray. Furthermore, if any cable in a stack of trays was calculated to be damaged, all of the cables in the stack were assumed to be damaged. In other words, neither shielding nor delayed fire growth from tray to tray were considered in the fire damage calculations.

7. Lack of knowledge about the termination points (i.e., functions) of specific cables in a compartment was treated as causing failure of the entire channel in which the cable belongs, if one cable was calculated as damaged.

8. Selected credit for Balance of Plant (BOP) was included in the 2003 PRA fire update to reflect BOP availability for fires that are in areas of the plant that obviously do not affect the BOP availability.

9. Check valves, manual valves and valve bodies are unaffected by fires.

10. Fires at the valve operator fail the valve in its as-is position. For example, MOVs fail as is.

Limitations and other precautions regarding the fire IPEEE quantification for Hope Creek are as follows:

1. Multiple Spurious Operation (MSO): At the time of the Hope Creek IPEEE, the treatment of MSOs was rudimentary. As noted in Section A.3.3, "hot shorts" were considered for selected fires, e.g., fires affecting ISLOCA, spurious ADS, SORV, and LOCAs.
2. The explicit identification and modeling of instrumentation required to support PRA credited operator actions is not addressed. The industry treatment for this task is still being developed.
3. The Balance of Plant - The BOP is not fully treated. BOP support system failure is conservatively assumed in most areas.
4. The design and plant layout of Hope Creek make fire propagation to multiple compartments unlikely compared to the fire risk in individual compartments. An explicit multi-compartment review was not performed.
5. Seismic Fire Interactions walkdown was performed. No quantified risk contributors were identified.
6. The Hope Creek fire hazard analysis is probabilistically evaluated to provide insights regarding the focused EDG AOT application. The fire probabilistic model is derived from the IPEEE model. These models reside within an integrated application specific model. It is recognized that these fire probabilistic models do not meet current PRA standards. The purpose of using this models is two-fold:
   - Demonstrate that the quantitative impact on the risk metric calculations is small
   - Identify the critical insights that may arise from the consideration of these hazards

   Both of these objectives are met in the EDG AOT evaluation. In addition, sensitivity cases are implemented to demonstrate possible variations in the results due to modeling assumptions in these external hazard probabilistic models.

   The quantitative results from the integrated assessment of internal and external events is also interpreted qualitatively to confirm that the results are consistent with the plant design and that the resulting cutsets are appropriate.

> This approach is judged more useful than a strictly qualitative approach to the assessment of fire risk impacts on the EDG AOT application.

Given all of the above, the Hope Creek IPEEE model incorporated into the EDG AOT Extension Application Model is judged to provide a meaningful representation of fire CDF contributors, and is appropriate for use in risk-informed decision making.

A.3.3 Treatment of "Hot Shorts", LOCAs and Interfacing System LOCAs

A "hot short" is one in which control wiring or contacts which should be insulated from one another come in contact in a way that allows power to the controlled component. For example, this may occur if two wires, from the opposite poles of the switch, contact each other either directly or indirectly. Such shorts sometimes have the capability of creating an inadvertent signal in equipment which would either initiate an unwanted change of state (e.g., starting or stopping a pump, or opening a closed valve) or in the case of certain closed motor operated valves, unwanted motor operation.

This assessment considered the possibility of hot shorts for each scenario and commented on the possibility under the heading Initiating Event(s) within the Fire Scenario Analysis worksheets. Only the control room, lower control equipment room, and switchyard blockhouse were found susceptible to hot short actuation of equipment. The occurrence of hot shorts might cause an SORV (LOCA), LOOP, or Loss of SWS/SACS. These effects were considered during the calculation of core damage frequency.

This assessment used a value of 30%; that is, given a fire scenario in which a hot short might cause unwanted effects, the likelihood of those effects is 30% of the likelihood of the fire scenario. The remaining 70% of the fire scenario is treated as if hot short did not occur.

Fire induced LOCAs were found to occur only because of hot shorts, as described above, in cabinets that contain control wiring for SRVs or ADS. This can occur only in the control room and lower control equipment room. Using the highly conservative value of the conditional probability of hot shorts, the total core damage frequency associated with fire induced LOCAs was found to be approximately 4E-07/yr.

An analysis of the interfacing high to low pressure systems was performed for the HCGS PRA. The analysis was reviewed for applicability to fire scenarios. No high to low pressure interface is susceptible for fire scenarios, with one exception. This is because all boundaries are protected by at least two diverse, closed isolation valves, one of which is a check valve or stop check valve. Even if a sustained hot short opened an MOV, the check valves are not susceptible to opening by fire scenarios. The one exception to this is the RHR shutdown cooling suction lines which are isolated by two closed MOVs. The shutdown cooling suction valve (BCHVF008) is disabled at the circuit breaker by a key switch to prevent inadvertent opening during fires.

A.3.4 Fire Risk Contributors

The above fire analysis from the IPEEE was based on a 1994 PRA model. The HCGS 2003 PRA model update included the following changes to the internal fires portion of the PRA model:

- Fire Initiating event frequencies were updated to incorporate the NRC's latest fire events data base available in 2003.
- The immediate impact of the fire on the initiating event characteristics were re-examined to eliminate the excess conservatism in the initiating event definition. For example, some fire events previously modeled conservatively as MSIV closure were changed to turbine trip events based on an assessment of the specific failures caused by the fire.
- The 2003 PRA system models and accident sequence models were used in the model.

- One of the dominant fire contributors to the risk profile from the IPEEE is a significant fire in an EDG compartment. This is because the IPEEE model assumes that the fire fails the EDG and causes a loss of offsite AC power. This, in turn, relates to the assumption that the two offsite power bus ducts 10A108 and 10A109 traverse all 4 EDG compartments and that the fire would cause shorting to ground of both of these buses.

  However, the 2003 PRA update and more recent walkdowns have both indicated that in two of the diesel compartments (A and B) one of the two bus ducts is wrapped with an adequate fire barrier for the postulated fire:

  - In the "A" EDG compartment: bus duct 10A108 is wrapped preventing a LOOP if there is a fire in the "A" EDG compartment.
  - In the "B" EDG compartment: bus duct 10A109 is wrapped preventing a LOOP if there is a fire in the "B" EDG compartment.

Incorporation of these insights into the HCGS fire IPEEE model eliminates some of the dominant contributors to the IPEEE fire risk profile and in particular to the cutsets that affect the delta-risk for the application involving an extended EDG AOT.

The EDG AOT extension application model that includes the fire PRA is based on the 2008B (HC108B) internal events PRA model data update plus the system and accident sequence updated internal events analysis.

Results Review

One perspective of the fire hazard impact on the HCGS risk profile for this application comes from an examination of the risk contributions by fire initiating events. The risk selected for examination is the delta-risk between the configuration specific risk with the EDG out of service (OOS) compared with the average base case risk. The EDG selected to be OOS is the limiting EDG, i.e., EDG "B".

Table A.3-1 summarizes the fire initiating events that contribute to the delta-risk (i.e., delta-CDF) associated with the EDG "B" being OOS compared with the base case. These are ranked by Fussell-Vesely (FV) importance.

Table A.3-2 summarizes the same information for the LERF end state.

As expected, the dominant fire initiating event contributors to the delta-CDF when EDG "B" is OOS are the following:

Initiator	Impact on Delta CDF
• %IE-FIRE37 - DG Room D Fire	5.98%
• %IE-FIRE28 - Control Bldg Corridor on 102' El.	0.66%
• %IE-FIRE20 - DG Room C Fire	0.29%
• %IE-FIRE59 - Turbine Bldg Spaces on 102' El. (Large Fire)	0.29%
• %IE-FIRE58 - Turbine Bldg Spaces on 102' El. multiple (Small Fire)	0.19%
• %IE-FIRE56 - Control Equipment Room	0.128%

The above initiators result in both failure of an EDG and an induced LOOP.

The dominant fire initiating event contributors to the delta-LERF when EDG "B" is OOS are the following:

Initiator	Impact on Delta LERF
• %IE-FIRE37 - DG Room D Fire	8.22%
• %IE-FIRE28 - Control Bldg Corridor on 102' El.	0.43%
• %IE-FIRE59 - Turbine Bldg Spaces on 102' El. multiple (Large Fire)	0.34%
• %IE-FIRE20 - DG Room C Fire	0.31%
• %IE-FIRE58 - Turbine Bldg Spaces on 102' El. multiple (Small Fire)	0.22%
• %IE-FIRE56 - Control Equipment Room	0.15%

The importance measures indicate:

- The fire events that lead to a loss of offsite AC power are the most important contributors to the delta-risk profile (i.e., risk when A or B EDG is OOS).

Because only a small fraction of the fire induced core damage sequences lead to a loss of offsite AC power, the contribution of fire accident sequences to the delta-risk models that reflect the EDG "B" out of service is relatively small:

Hazard	Risk Metric	
	ΔCDF	ΔLERF
Internal	90.2%	88.1%
Fire	7.9%	10.0%
Seismic	1.9%	1.9%

A.3.5 Fire Risk Analysis Insights

Based on the preceding evaluations, fire risk can be a significant contributor to the base model. However, fire is a relatively small contributor to the specific application, i.e., EDG A and B AOT extension.

Important Equipment Configuration

See Appendix D.

Review of Compensatory Measure Impacts on Important Fire Areas

Based on a review of results from the fire PRA contributors, the following compensatory actions are highlighted as important to reduce the risk from fire events during the performance of the extended AOT.

- Proper standby alignment of the opposite EDG train should be ensured prior to entry into the AOT as this would reduce the contribution from potential pre-initiator errors.
- Besides the protected opposite EDG trains, elective maintenance should be avoided on all SACS and SSW trains that support the protected EDG trains.
- Minimize general plant testing and electrical maintenance with the EDG OOS.
- Increase fire protection measures (e.g., transient material surveillance) for protected EDG train rooms.

Table A.3-1

IMPORTANCE SUMMARY OF FIRE INITIATORS THAT CONTRIBUTE TO DELTA-RISK (CDF) CUTSETS FOR EDG "B" OOS

Delta Risk Compensatory Measures 3-6			
Fire Initiators	Probability	F-V	
Summation:	**2.50E-02**	**7.90E-02**	Description
%IE-FIRE37	1.00E-04	5.98E-02	DG Room (D) Fire Scenario 5304_2
%IE-FIRE28	1.25E-05	6.56E-03	Cmprtmnt 5339 Fire Scenario 5339_2
%IE-FIRE20	1.00E-04	2.85E-03	DG Room (C) Fire Scenario 5306_2
%IE-FIRE59	1.25E-04	2.85E-03	Cmprtmnt 1315-1322 Fire Scenario 1315_2
%IE-FIRE58	8.27E-05	1.87E-03	Cmprtmnt 1315-1322 Fire Scenario 1315_1
%IE-FIRE56	5.70E-05	1.28E-03	Cmprtmnt 5302 Fire Scenario 5302_8
%IE-FIRE24	4.20E-04	6.56E-04	Cmprtmnt 5501 Fire Scenario 5501_1
%IE-FIRE33	3.40E-04	5.59E-04	Cmprtmnt 5605/5631 Fire Scenario 5605_5
%IE-FIRE04	4.69E-04	5.07E-04	Control Room Fire Scenario Small Cab_4 (Loss of HPCI)
%IE-FIRE43	2.95E-04	4.33E-04	Cmprtmnt 4301-4311 Fire Scenario 4309_1
%IE-FIRE11	1.65E-03	4.05E-04	Cmprtmnt 5416/5417 Fire Scenario 5416_1
%IE-FIRE13	1.00E-04	3.91E-04	DG Room (A) Fire Scenario 5307_2
%IE-FIRE22	1.00E-04	1.36E-04	DG Room (B) Fire Scenario 5305_2
%IE-FIRE41	6.99E-05	1.11E-04	Cmprtmnt 4301-4311 Fire Scenario 4301_1
%IE-FIRE29	1.22E-03	6.54E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_1
%IE-FIRE30	3.40E-04	6.36E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_2
%IE-FIRE35	1.11E-03	5.72E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_7
%IE-FIRE44	2.80E-04	5.00E-05	Cmprtmnt 4301-4311 Fire Scenario 4309_2
%IE-FIRE25	3.40E-04	4.55E-05	Cmprtmnt 5501 Fire Scenario 5501_2
%IE-FIRE32	3.40E-04	4.55E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_4
%IE-FIRE36	4.00E-03	4.40E-05	DG Room (D) Fire Scenario 5304_1
%IE-FIRE27	3.75E-05	3.94E-05	Cmprtmnt 5339 Fire Scenario 5339_1
%IE-FIRE12	4.00E-03	2.67E-05	DG Room (A) Fire Scenario 5307_1
%IE-FIRE05	6.03E-04	1.96E-05	Control Room Fire Scenario Small Cab_5 (Loss of RHR A and C)
%IE-FIRE19	4.00E-03	1.83E-05	DG Room (C) Fire Scenario 5306_1
%IE-FIRE42	1.40E-04	1.41E-05	Cmprtmnt 4301-4311 Fire Scenario 4310_1
%IE-FIRE14	2.95E-04	1.17E-05	CRD Area Fire Scenario 4202_1
%IE-FIRE03	2.94E-04	1.15E-05	Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)
%IE-FIRE23	1.65E-03	1.05E-05	Cmprtmnt 5412/5413 Fire Scenario 5412_1
%IE-FIRE02	2.45E-04	8.85E-06	Control Room Fire Scenario Small Cab_2 (Loss of SSWS)
%IE-FIRE57	2.29E-04	7.80E-06	Cmprtmnt 5302 Fire Scenario 5302_9
%IE-FIRE48	5.70E-05	7.25E-06	Cmprtmnt 5302 Fire Scenario 5302_1

Table A.3-1

IMPORTANCE SUMMARY OF FIRE INITIATORS THAT CONTRIBUTE TO DELTA-RISK (CDF) CUTSETS FOR EDG "B" OOS

Delta Risk Compensatory Measures 3-6			
Fire Initiators	Probability	F-V	
Summation:	**2.50E-02**	**7.90E-02**	Description
%IE-FIRE01	2.10E-04	7.15E-06	Control Room Fire Scenario Small Cab_1 (Loss of SACS)
%IE-FIRE34	1.36E-04	3.85E-06	Cmprtmnt 5605/5631 Fire Scenario 5605_6
%IE-FIRE49	5.70E-05	3.83E-06	Cmprtmnt 5302 Fire Scenario 5302_2
%IE-FIRE60	8.29E-04	3.60E-06	Cmprtmnt 4303 Fire Scenario 4303_1
%IE-FIRE26	7.00E-06	3.23E-06	Cmprtmnt 5501 Fire Scenario 5501_3
%IE-FIRE45	2.51E-06	3.00E-06	Cmprtmnt 4301-4311 Fire Scenario 4301_2
%IE-FIRE31	3.40E-04	1.21E-06	Cmprtmnt 5605/5631 Fire Scenario 5605_3
%IE-FIRE16	7.25E-05	1.04E-06	CRD Area Fire Scenario 4202_3
%IE-FIRE17	7.25E-05	1.04E-06	CRD Area Fire Scenario 4202_4
%IE-FIRE62	9.22E-07	1.01E-06	Cmprtmnt 4303 Fire Scenario 4303_3
%IE-FIRE53	5.70E-05	7.00E-07	Cmprtmnt 5302 Fire Scenario 5302_5
%IE-FIRE54	5.70E-05	7.00E-07	Cmprtmnt 5302 Fire Scenario 5302_6
%IE-FIRE55	5.70E-05	7.00E-07	Cmprtmnt 5302 Fire Scenario 5302_7
%IE-FIRE40	1.12E-07	2.72E-07	Cmprtmnt 3425/5401 Fire Scenario 5401_3
%IE-FIRE06	2.55E-05	2.28E-07	Control Room Fire Scenario Large Cab_1 (MSIV Closure)

Table A.3-2

IMPORTANCE SUMMARY OF FIRE INITIATORS THAT CONTRIBUTE TO DELTA-RISK (LERF) CUTSETS FOR EDG "B" OOS

Delta Risk Compensatory Measures 3-6			
Fire Initiators	Probability	F-V	Description
Summation:	**2.12E-02**	**1.00E-01**	
%IE-FIRE37	1.00E-04	8.22E-02	DG Room (D) Fire Scenario 5304_2
%IE-FIRE28	1.25E-05	4.27E-03	Cmprtmnt 5339 Fire Scenario 5339_2
%IE-FIRE59	1.25E-04	3.40E-03	Cmprtmnt 1315-1322 Fire Scenario 1315_2
%IE-FIRE20	1.00E-04	3.17E-03	DG Room (C) Fire Scenario 5306_2
%IE-FIRE58	8.27E-05	2.19E-03	Cmprtmnt 1315-1322 Fire Scenario 1315_1
%IE-FIRE56	5.70E-05	1.47E-03	Cmprtmnt 5302 Fire Scenario 5302_8
%IE-FIRE04	4.69E-04	6.81E-04	Control Room Fire Scenario Small Cab_4 (Loss of HPCI)
%IE-FIRE33	3.40E-04	6.43E-04	Cmprtmnt 5605/5631 Fire Scenario 5605_5
%IE-FIRE13	1.00E-04	3.26E-04	DG Room (A) Fire Scenario 5307_2
%IE-FIRE03	2.94E-04	3.25E-04	Control Room Fire Scenario Small Cab_3 (Loss of Emer. Bat.)
%IE-FIRE24	4.20E-04	2.93E-04	Cmprtmnt 5501 Fire Scenario 5501_1
%IE-FIRE02	2.45E-04	2.69E-04	Control Room Fire Scenario Small Cab_2 (Loss of SSWS)
%IE-FIRE01	2.10E-04	2.19E-04	Control Room Fire Scenario Small Cab_1 (Loss of SACS)
%IE-FIRE43	2.95E-04	1.82E-04	Cmprtmnt 4301-4311 Fire Scenario 4309_1
%IE-FIRE36	4.00E-03	1.22E-04	DG Room (D) Fire Scenario 5304_1
%IE-FIRE41	6.99E-05	1.17E-04	Cmprtmnt 4301-4311 Fire Scenario 4301_1
%IE-FIRE06	2.55E-05	7.63E-05	Control Room Fire Scenario Large Cab_1 (MSIV Closure)
%IE-FIRE12	4.00E-03	6.82E-05	DG Room (A) Fire Scenario 5307_1
%IE-FIRE19	4.00E-03	6.82E-05	DG Room (C) Fire Scenario 5306_1
%IE-FIRE29	1.22E-03	4.50E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_1
%IE-FIRE35	1.11E-03	4.09E-05	Cmprtmnt 5605/5631 Fire Scenario 5605_7
%IE-FIRE11	1.65E-03	3.83E-05	Cmprtmnt 5416/5417 Fire Scenario 5416_1
%IE-FIRE27	3.75E-05	1.05E-05	Cmprtmnt 5339 Fire Scenario 5339_1
%IE-FIRE25	3.40E-04	7.78E-06	Cmprtmnt 5501 Fire Scenario 5501_2
%IE-FIRE32	3.40E-04	7.78E-06	Cmprtmnt 5605/5631 Fire Scenario 5605_4
%IE-FIRE22	1.00E-04	7.21E-06	DG Room (B) Fire Scenario 5305_2
%IE-FIRE14	2.95E-04	4.58E-06	CRD Area Fire Scenario 4202_1
%IE-FIRE57	2.29E-04	3.56E-06	Cmprtmnt 5302 Fire Scenario 5302_9
%IE-FIRE45	2.51E-06	2.98E-06	Cmprtmnt 4301-4311 Fire Scenario 4301_2
%IE-FIRE30	3.40E-04	2.49E-06	Cmprtmnt 5605/5631 Fire Scenario 5605_2
%IE-FIRE42	1.40E-04	2.34E-06	Cmprtmnt 4301-4311 Fire Scenario 4310_1
%IE-FIRE44	2.80E-04	2.05E-06	Cmprtmnt 4301-4311 Fire Scenario 4309_2

Table A.3-2

IMPORTANCE SUMMARY OF FIRE INITIATORS THAT CONTRIBUTE TO DELTA-RISK (LERF) CUTSETS FOR EDG "B" OOS

Delta Risk Compensatory Measures 3-6			
Fire Initiators	Probability	F-V	Description
Summation:	**2.12E-02**	**1.00E-01**	
%IE-FIRE34	1.36E-04	1.27E-06	Cmprtmnt 5605/5631 Fire Scenario 5605_6

A.4 SEISMIC ASSESSMENT

A Seismic Probabilistic Risk Assessment (PRA) analysis approach was taken to identify potential seismic vulnerabilities at the Hope Creek Generating Station. The Seismic PRA method is an acceptable methodology identified in NUREG-1407. This PRA technique includes consideration of the following elements:

- Seismic hazard analysis
- Seismic fragility assessment
- Seismic systems analysis
- Quantification of the seismically induced core damage frequency

The seismic analysis of the HCGS also included the following elements:

- Human interactions and recovery actions under seismic conditions
- Relay chatter during a seismic event
- Soil seismic liquefaction, settlement, and slope stability effects
- Containment performance during a seismic event

Seismic hazard analysis was performed to estimate the annual frequency of exceeding different levels of seismic ground motion at the plant site. The seismic hazard analysis focus is on the identification of the sources of earthquakes that may impact the Hope Creek site, evaluation and assessment of the frequencies of occurrence of earthquakes of different magnitudes, estimation of the intensity of earthquake-induced ground motion (e.g., peak ground acceleration) (PGA) at the site, and finally, the integration of this information to estimate the frequency of exceedance for selected levels of ground motion. For the Hope Creek site, there are two published site-specific hazard studies (EPRI and NRC). The results of these studies were used in the IPEEE.

This section provides information regarding the quantitative assessment of the seismic risk implications of having an EDG out of service using the Hope Creek EDG AOT Extension Application Model. In order to evaluate the potential seismic risk implications, a seismic risk assessment based on the IPEEE evaluation is provided to evaluate the role of the EDGs in mitigating seismic-induced events.

The seismic hazard contribution to the CDF risk metric for Hope Creek is relatively low compared with the "all hazards" calculated CDF. The following table compares these PRA results.

Configuration	PRA Model	CDF (/yr)	%Contribution
Base[1]	Base Model[1]	2.18E-5	100%
	Seismic Contribution	6.86E-7	3.2%
EDG "B" Unavailable[1]	EDG B OOS[2]	2.89E-5	100%
	Seismic Contribution[2]	8.32E-7	2.9%

(1) Includes no credit for Salem Unit 3 Gas Turbine.
(2) The EDG B OOS represents the limiting EDG OOS, i.e., highest configuration risk.

A.4.1 Methodology

The seismic analysis that is documented in the IPEEE is used as the basis for the HCGS seismic hazard quantification. It includes the following attributes:

- Seismic: The seismic hazard curves used in the quantification are from EPRI NP-6395-D, Probabilistic Seismic Hazard Evaluation at Nuclear Power Plant Sites in the Central and Eastern United States.
- HRA: The HEPs are modified to reflect the increased probability of failure under seismic events (e.g., increased stress, increased work load, limitations in access).
- LERF: Treatment of seismic events is the same as in the internal events analysis. This may introduce some non-conservative bias in the base model but is judged to have limited impact on the risk metrics for this PRA application because the delta risk from the seismic hazard is principally from low seismic magnitude earthquakes which leave the infrastructure intact.

The dominant contributors to the seismic risk profile are as follows:

Base Model[1]

- %IE-SET36 — Seismic events that cause failure of the 120V panel 481
- %IE-SET18 — Seismic events that cause a loss of offsite AC power

EDG B OOS

- %IE-SET36 — Seismic events that cause failure of the 120V panel 481
- %IE-SET18 — Seismic events that cause a loss of offsite AC power

EDG B OOS -- Delta Risk[2]: The cutsets that dominate the delta risk are derived from the following initiator significantly increased because of the EDG OOS condition

- %IE-SET18 — Seismic Equipment Damage State SET-18 (Impacts LOOP)

Table A.4-1 provides a summary of the seismic initiating events in the PRA model and their impacts on the PRA logic models.

A.4.2 Limitations of Seismic PRA

The Hope Creek seismic hazard analysis is probabilistically evaluated to provide insights regarding the focused EDG AOT application. The seismic probabilistic model is derived from the IPEEE model. These models reside within an integrated application specific model. It is recognized that the seismic probabilistic models do not meet current PRA standards. The purpose of using this models is two-fold:

- Demonstrate that the quantitative impact on the risk metric calculations is small (See Section A.4 Introduction)

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(1) Includes no credit for Salem Unit 3 Gas Turbine.
(2) Delta risk refers the incremental increase in the CDF due to the EDG B being unavailable.

- Identify the critical insights that may arise from the consideration of these hazards (See Section A.4.3)

Both of these objectives are met in the EDG AOT evaluation. In addition, sensitivity cases are implemented to demonstrate possible variations in the results due to modeling assumptions in these external hazard probabilistic models.

The quantitative results from the integrated assessment of internal and external events is also interpreted qualitatively to confirm that the results are consistent with the plant design and that the resulting cutsets are appropriate. (See Section A.4.3)

This approach is judged more useful than a strictly qualitative approach to the assessment of seismic risk impacts on the EDG AOT application.

A.4.3 Risk Implications for EDG OOS

The calculated seismic induced CDF in the base model is approximately 6.9E-07/yr.

For the EDG OOS cases, the seismic induced LOOP events with EDGs not failed by the seismic event are the dominant contributors to the delta risk[(2)]. Accident scenarios involving postulated seismic-induced EDG failure have no contribution to the delta risk estimates of this analysis. This fact is due to the high correlation of seismic induced failures of similar equipment in like locations. Input from fragility experts indicates that there is a strong correlation among similar equipment on the same floor such that seismic induced failure of one component is perfectly correlated with failure of the similar components, i.e., all EDGs would be failed (this is a standard seismic PRA modeling approach). Therefore, for accidents scenarios involving seismic induced EDG failure, there is no difference in the CDF whether one of the EDGs is OOS for maintenance or not.

A.4.4 Seismic Risk Impact Conclusion

Seismic quantitative analyses were performed to consider the potential seismic contribution for an EDG out of service during the AOT configuration. This included an evaluation of 38 separate seismic initiating events.

The seismic results are quantitatively included in the calculated ΔCDF and ΔLERF.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [1]	Description	Plant Impacts [2]	PRA Model Integration [3]
%IE-SET02	Seismic-Induced Equipment Damage State SET-02 (Impacts - S2)	S2	• Model with SLOCA ET sequences. Gate GSET-SLOCA (an 'OR' gate of %IE-SET02,04,06,10) under gate SLOCA.
%IE-SET03	Seismic-Induced Equipment Damage State SET-03 (Impacts - CV)	TF and CV	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET04	Seismic-Induced Equipment Damage State SET-04 (Impacts - S2, CV)	S2 and CV	• Model with SLOCA ET sequences. Gate GSET-SLOCA (an 'OR' gate of %IE-SET02,04,06,10) under gate SLOCA. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET05	Seismic-Induced Equipment Damage State SET-05 (Impacts – CST)	TF and CT	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.
%IE-SET06	Seismic-Induced Equipment Damage State SET-06 (Impacts - S2, CST)	S2 and CT	• Model with SLOCA ET sequences. Gate GSET-SLOCA (an 'OR' gate of %IE-SET02,04,06,10) under gate SLOCA. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [1]	Description	Plant Impacts [2]	PRA Model Integration [3]
%IE-SET07	Seismic-Induced Equipment Damage State SET-07 (Impacts - CST, CV)	TF, CT and CV	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET09	Seismic-Induced Equipment Damage State SET-09 (Impacts - 250V)	TF and HP	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR.
%IE-SET10	Seismic-Induced Equipment Damage State SET-10 (Impacts - S2, 250V)	S2 and HP	• Model with SLOCA ET sequences. Gate GSET-SLOCA (an 'OR' gate of %IE-SET02,04,06,10) under gate SLOCA. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR.
%IE-SET11	Seismic-Induced Equipment Damage State SET-11 (Impacts - 250V, CV)	TF, HP and CV	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [1]	Description	Plant Impacts [2]	PRA Model Integration [3]
%IE-SET13	Seismic-Induced Equipment Damage State SET-13 (Impacts - 250V, CST)	TF, HP and CT	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.
%IE-SET15	Seismic-Induced Equipment Damage State SET-15 (Impacts - 250V, CST, CV)	TF, HP, CT and CV	• Model with LOFW ET sequences. Gate GSET-TRANS (an 'OR' gate of %IE-SET03,05,07,09,11, 13,15) under gate LOFW. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET18	Seismic-Induced Equipment Damage State SET-18 (Impacts - LOOP)	OP	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL.
%IE-SET19	Seismic-Induced Equipment Damage State SET-19 (Impacts - S2, LOOP)	S2 and OP	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [(1)]	Description	Plant Impacts [(2)]	PRA Model Integration [(3)]
%IE-SET20	Seismic-Induced Equipment Damage State SET-20 (Impacts - LOOP, CV)	OP and CV	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET21	Seismic-Induced Equipment Damage State SET-21 (Impacts - S2, LOOP, CV)	S2, OP and CV	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET22	Seismic-Induced Equipment Damage State SET-22 (Impacts - LOOP, CST)	OP and CT	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.
%IE-SET23	Seismic-Induced Equipment Damage State SET-23 (Impacts - S2, LOOP, CST)	S2, OP and CT	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator (1)	Description	Plant Impacts (2)	PRA Model Integration (3)
%IE-SET24	Seismic-Induced Equipment Damage State SET-24 (Impacts - LOOP, CST, CV)	OP, CT and CV	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET25	Seismic-Induced Equipment Damage State SET-25 (Impacts - S2, LOOP, CST, CV)	S2, OP, CT and CV	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET26	Seismic-Induced Equipment Damage State SET-26 (Impacts - LOOP, 250V)	OP and HP	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator (1)	Description	Plant Impacts (2)	PRA Model Integration (3)
%IE-SET27	Seismic-Induced Equipment Damage State SET-27 (Impacts - S2, LOOP, 250V)	S2, OP and HP	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR.
%IE-SET28	Seismic-Induced Equipment Damage State SET-28 (Impacts - LOOP, 250V, CV)	OP, HP and CV	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [(1)]	Description	Plant Impacts [(2)]	PRA Model Integration [(3)]
%IE-SET29	Seismic-Induced Equipment Damage State SET-29 (Impacts - S2, LOOP, 250V, CV)	S2, OP, HP, and CV	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET30	Seismic-Induced Equipment Damage State SET-30 (Impacts - LOOP, 250V, CST)	OP, HP, and CT	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator [1]	Description	Plant Impacts [2]	PRA Model Integration [3]
%IE-SET31	Seismic-Induced Equipment Damage State SET-31 (Impacts - S2, LOOP, 250V, CST)	S2, OP, HP, and CT	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY.
%IE-SET32	Seismic-Induced Equipment Damage State SET-32 (Impacts - LOOP, 250V, CST, CV)	OP, HP, CT and CV	• Model with LOOP ET sequences. Gate GSET-LOOP (an 'OR' gate of %IE-SET18,20,22,24,26,28,30,32) under gate LOOP. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator (1)	Description	Plant Impacts (2)	PRA Model Integration (3)
%IE-SET33	Seismic-Induced Equipment Damage State SET-33 (Impacts - S2, LOOP, 250V, CST, CV)	S2, OP, HP, CT, and CV	• Model with SLOCA ET sequences. Gate GSET-LOOP-SLOCA (an 'OR' gate of %IE-SET19,21,23, 25,27,29,31,33) under gate SLOCA. • LOOP impact on equipment modeled with gate LOOP under gate LOPIEANDLBL. • Impact on 250VDC modeled with gate GSET-250V (an 'OR' gate of %IE-SET09,10,11,13,15,26,27, 28,29,30,31,32,33) under gates GA50100, GADX100, GB60100, GBDX100, and GADX100-4HR. • Impact on CST modeled with gate GSET-CST (an 'OR' gate of %IE-SET05,06,07,13,15,22,23,24,25, 30,31,32,33) under gate CST-SUPPLY. • Impact on Cont. Vent modeled with gate GSET-CV (an 'OR' gate of %IE-SET03,04,07,11,15,20,21,24, 25,28,29,32,33) under gate GCON113.
%IE-SET34	Seismic-Induced Equipment Damage State SET-34 (Impacts - CR, RSP)	CR and RSDOWN (leads directly to core damage)	• Modeled directly as a core damage sequence using gate GSET-CD-SEQS (an 'OR' gate of %IE-SET34, 35,36,37,38). • Model as failing FW, RHR, HPCI, RCIC, and ADS.
%IE-SET35	Seismic-Induced Equipment Damage State SET-35 (Impacts - 120V PNL482, RSP)	IC2 and RSDOWN (leads directly to core damage)	• Modeled directly as a core damage sequence using gate GSET-CD-SEQS (an 'OR' gate of %IE-SET34, 35,36,37,38). • Model as failing FW, RHR, HPCI, RCIC, and ADS.
%IE-SET36	Seismic-Induced Equipment Damage State SET-36 (Impacts - 120V PNL481)	IC1 (although manual control from Control Room may be possible, assumed to lead directly to core damage)	• Modeled directly as a core damage sequence using gate GSET-CD-SEQS (an 'OR' gate of %IE-SET34, 35,36,37,38). • Model as failing FW, RHR, HPCI, RCIC, and ADS.

Table A.4-1

SUMMARY OF HCGS SEISMIC INITIATING EVENTS, ASSOCIATED IMPACTS, AND PRA MODELING

Seismic Initiator (1)	Description	Plant Impacts (2)	PRA Model Integration (3)
%IE-SET37	Seismic-Induced Equipment Damage State SET-37 (Impacts - 125V)	DC (although manual control of safety-related systems may be possible, assumed to lead directly to core damage)	• Modeled directly as a core damage sequence using gate GSET-CD-SEQS (an 'OR' gate of %IE-SET34, 35,36,37,38). • Model as failing FW, RHR, HPCI, RCIC, and ADS.
%IE-SET38	Seismic-Induced Equipment Damage State SET-38 (Impacts - 1E Panel Room Ventil.)	HV (conservatively assumed to lead directly to a core damage)(4)	• Modeled directly as a core damage sequence using gate GSET-CD-SEQS (an 'OR' gate of %IE-SET34, 35,36,37,38). • Model as failing FW, RHR, HPCI, RCIC, and ADS.

Notes to Table A.4-1:

(1) The seismic initiators included in the HCGS PRA are based on the Seismic Event Tree (SET) of the HCGS IPEEE seismic PRA. These seismic initiators include the convolution of the seismic hazard curve and one or more seismic-induced failures (and in a few cases an operator error); they do not include random equipment failures.

(2) The plant impacts associated with each seismic damage state use the following nomenclature:

- OP: Seismic-induced Loss of Offsite Power
- S2: Seismic-induced Small LOCA
- TF: Seismic-induced Loss of Feedwater (seismic events that do not cause a LOOP or a SLOCA are modeled as a Loss of Feedwater)
- CT: Seismic-induced failure of the Condensate Storage Tank
- CV: Seismic-Induced failure of the Containment Vent Function (due to seismic-induced failure of 120VAC fuse panels 1Y-F-401/402/403/404)
- HP: Seismic-induced failure of 250VDC MCCs 10D251 & 10D261 and buses 10D450 & 10D460.
- DC: Seismic-induced failure of 1E 125VDC (i.e., Panels 1A/B/C/D-D417)
- IC1: Seismic-induced failure of 1E 120VAC PNL481 (i.e., Panels 1A/B/C/DJ481)
- IC2: Seismic-induced failure of 1E 120VAC PNL482 (i.e., Panels 1A/B/C/DJ482)
- CR: Seismic-induced failure of Control Room Ventilation (due to seismic-induced failure of dampers 1GKHD-9588AA/AB/BA/BB and 1GKHD-9594A)
- HV: Seismic-induced failure of 1E Panel Room fans 1A-VH408 and 1B-VH408 and failure to align alternate room cooling

(3) In addition to the model integration items listed in the table, the integration of the seismic events into the HCGS PRA also involves incorporating increased human error probabilities consistent with the approach used in the HCGS IPEEE.

(4) Loss of room cooling to the 1E Panel Room is treated conservatively in the seismic accident sequence analysis. The HCGS internal events analysis does not require 1E Panel Room ventilation.

REFERENCES

[A-1] PSEG, "Hope Creek Generating Station Individual Plant Examination for External Events," July 1997.

[A-2] USNRC, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking," NUREG-1855, March 2009.

[A-3] Exelon Risk Management Team, *Hope Creek Generating Station Probabilistic Risk Assessment Fire PRA Results Notebook, LGS104C and LGS204C Models*, Revision 0, LG-PRA-021.06, March 2008.

[A-4] USNRC, "Analysis of Core Damage Frequency: Peach Bottom, Unit 2, External Events", NUREG/CR-4550, Vol. 4, Rev. 1, Part 3, December, 1990.

[A-5] USNRC, "Revised Livermore Seismic Hazard Estimates for 69 Sites East of the Rocky Mountains," NUREG-1488, April 1994.

[A-6] USNRC, "Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences," NUREG/CR-6544, April 1998.

[A-7] USNRC, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," NUREG/CR-6890, December, 2005.

Appendix B

UNCERTAINTY ANALYSIS

Appendix B

UNCERTAINTY ANALYSIS

This appendix evaluates epistemic uncertainties that could impact the EDG AOT extension assessment. The subsections included are as follows:

- Section B.1 provides a breakdown of the contributors to the CDF risk increase associated with the EDG AOT extension LAR to provide a framework for performing the uncertainty analysis.
- Section B.2 elaborates on the three types of epistemic uncertainty: parameter, model, and completeness uncertainties.
- Section B.3 provides the sensitivity analysis to assist decision makers in examining potential uncertainties.
- Section B.4 summarizes the insights obtained from the assessment.

Note that this effort focuses on the internal events and internal floods, fire, and seismic quantified PRA results. The treatment of modeling uncertainties for the Hope Creek PRA encompasses an extensive set of investigations that span the time period from before NUREG-1855 (see the HCGS PRA Summary Notebook for HC108B) was issued until the current EDG AOT application (Appendix F). Figure B.0-1 is a simplified flowchart that shows the interrelationship of the documented uncertainty investigations for Hope Creek.

The following sections address candidate modeling uncertainties derived from both the application specific evaluations (Appendix A and Appendix B.1) and the candidate modeling uncertainties derived for the EDG AOT application from the generic evaluations documented in Appendices F and G. The calculations in this appendix are performed with the compensatory measures recommended for inclusion in the Technical Specification Bases when the EDG A or B is out of service[1]. In addition, the "Base" model is developed assuming that the Salem Unit 3 gas turbine is not available.

[1] Compensatory Measures 3 through 6 summarized in the main report.

This is to account for the potential future site AC power configuration without the Salem Unit 3 gas turbine.

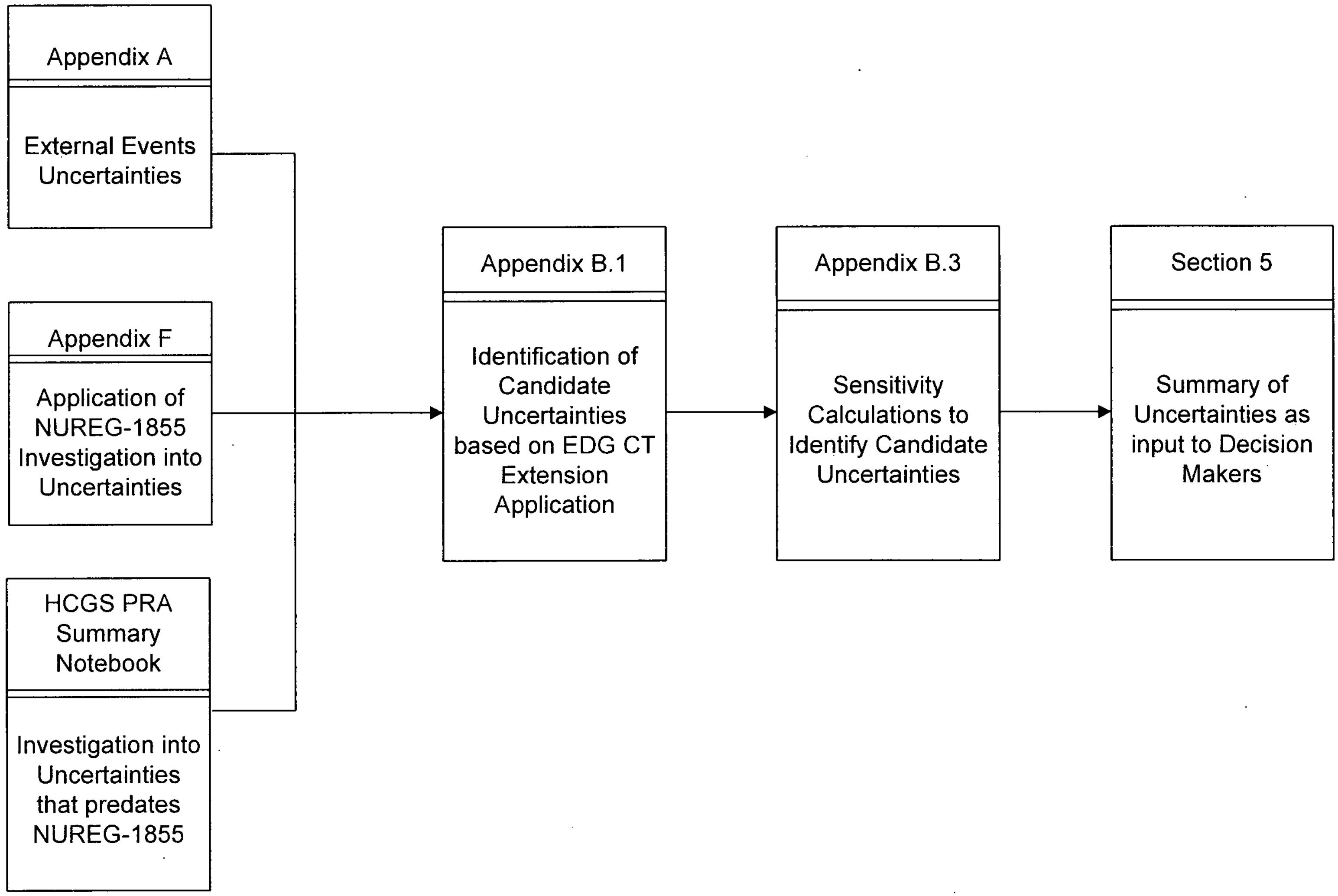

Figure B.0-1 Simplified Flowchart of Uncertainty Investigations as documented in the EDG AOT Extension Risk Assessment

B.1 DECOMPOSITION OF SIGNIFICANT RISK CONTRIBUTORS

To determine the relative importance of the individual risk contributors for this specific application, the focus is on the results of the CDF and LERF assessments for two separate cases: (1) PRA model with the "A" EDG out of service, and (2) PRA model with the "B" EDG out of service. To obtain insights regarding the changes to the base case risk profile when an EDG is out of service, the first step is to take the EDG out of service case results and remove the base case cutsets (e.g., using the CAFTA delete term process). This leads to a cutset file that is used to provide information regarding the significant cutsets that are dominating the delta-CDF[1] assessment.

The results for the delta-CDF[1] assessment are presented by initiator in Table B.1-1. The risk contributor display by initiator is a useful representation of the risk profile. The events or failures that challenge the emergency AC power system, and the mitigation alternatives to deal with the functional failures associated with the emergency AC power system that contribute to risk can be readily identified.

These results indicate that the loss of offsite AC power initiator in the internal events PRA is the most important contributor to the delta-CDF. Furthermore, it is found that most of the LOOP initiator contribution to CDF comes from LOOP initiating events that result from the weather related loss of offsite AC power.

The review of top initiating event contributors in Table B.1-1 provides a general understanding of the nature of the most important CDF contributors associated with the EDG unavailability. A more detailed and comprehensive view of the contributors is gained through a review of the cutsets and, in particular, the important individual basic event contributors. The dominant cutsets for each case are reviewed. As an example, the top 10 cutsets for each delta-CDF case are presented in Tables B.1-2 (for EDG A unavailable) and B.1-3 (for EDG B unavailable). These cutsets are for the PRA

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(1) Delta-CDF is the incremental increase in risk associated with the change from the base model configuration to the EDG out of service configuration.

evaluation of internal and external events in the application model derived for the delta-CDF evaluation. Table B.1-2 is for the delta-CDF evaluation for EDG "A" OOS. Table B.1-3 is the comparable calculation for EDG "B" OOS. These results are useful in understanding the important contributors and identifying potential sources of model uncertainty. Consistent with the contributions identified in Table B.1-1 by initiator, all of the top cutsets involve loss of offsite AC power scenarios due to LOOP initiators. This means that systems and functions that enable critical safety functions (e.g., RPV injection) to be maintained during a loss of offsite AC power scenarios become significant contributors.

To further confirm the insights obtained from the review of information in Tables B.1-1 through B.1-3, a review of importance measures for the delta-CDF cutsets for each of the two case runs is also performed.

The results of the assessments at the basic event level are provided in Tables B.1-4 (EDG A OOS) and B.1-5 (EDG B OOS) for the events with Fussell-Vesely down to 5E-3. For both cases, the top basic events down to 5E-3 (Fussell-Vesely Importance) sorted by percent contribution (Fussell-Vesely) are provided. Note that specific initiating event contributors have been purposely excluded from this list since they have already been assessed in Table B.1-1.

A review of the importance measure reports presented in Tables B.1-4 and B.1-5 identify the importance of the contributors. From the initiating event, cutset, and importance reviews, the following actions and events are noted as important to the assessment.

- LOOP initiating event
- Operator Actions ensuring proper standby alignment of the companion EDG train in the same mechanical division would reduce risk
- Operator Actions for the use of the portable battery charger to support DC power supply until AC recovery can be established and to align FPS to RPV injection
- HPCI reliability and availability

- SACS and associated valve operability
- EDG reliability
- EDG alignment

This evaluation provides input into the assessment of key model uncertainties in Section B.3.

While the ISLOCA frequency and the internal flooding analysis are important uncertainties to be aware of in the base model, these frequencies are not direct contributors to the change in risk for the EDG AOT extension and the calculation of the risk metrics (ΔCDF, ΔLERF, ICCDP, and ICLERP) for the EDG AOT extension application.

Table B.1-1

SIGNIFICANT INITIATOR CONTRIBUTIONS FOR THE PRA EVALUATIONS INVOLVING THE ΔCDF CUTSETS FOR INDIVIDUAL EDGs OUT OF SERVICE (OOS)

Figure of Merit	EDG "A" OOS Case	EDG "B" OOS Case
CDF_X	2.44E-05/yr	2.89E-05/yr
delta-CDF = CDF_X - CDF_{BASE}	2.60E-06/yr	7.10E-06/yr
Percent Contribution to delta-CDF[1]		
LOSS OF OFFSITE POWER	86.8%	79.9%
TRANSIENTS	5.8%	6.4%
SPECIAL IE AND INTERNAL FLOODS	0.1%	0.60%
LOCAs	4.7%	2.5%
FIRE	0.0%	8.7%
SEISMIC	2.8%	2.0%
TOTAL	100%	100%

(1) Delta-CDF is the result of difference between the EDG OOS case and the base model.

Table B.1-2

TOP 10 CUTSETS FOR ΔCDF FOR THE EDG "A" OOS CASE (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

#	Cutset Prob	Event Prob	Event	Description
1	4.70E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		1.31E-02	DGS-DGN-FS-BG400	DIVISION B DIESEL 1BG400 FAILS TO START
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
2	4.67E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		1.30E-02	DGS-DGN-TM-BG400	DGS TRAIN BG400 IN TEST AND MAINT
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
3	1.42E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		1.00E+00	ADS-XHE-OK-INHIB	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		6.00E-06	RX-FWR-ADS-POR	DEP OP ACT: FAIL TO INITIATE ADS, FW CNTRL, AND INITIATE PORTABLE GENERATOR
4	2.55E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		4.50E-01	DW-SHELL-RUPT	DRYWELL SHELL RUPTURE DISRUPTS INJECTION LINES AND FAILS RB SYS
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		1.58E-02	RHS-MDP-TM-PB	RHS PUMP TRAIN B IN TEST AND MAINT
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
5	9.31E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		1.00E+00	ADS-XHE-OK-INHIB	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
		1.31E-02	DGS-DGN-FS-DG400	DIVISION D DIESEL 1DG400 FAILS TO START
		3.00E-04	NR-U1X-DEP-SRV	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR

Table B.1-2

TOP 10 CUTSETS FOR ΔCDF FOR THE EDG "A" OOS CASE (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

#	Cutset Prob	Event Prob	Event	Description
6	9.24E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		1.00E+00	ADS-XHE-OK-INHIB	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
		1.30E-02	DGS-DGN-TM-DG400	DGS TRAIN DG400 IN TEST AND MAINT
		3.00E-04	NR-U1X-DEP-SRV	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
7	7.89E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		1.00E+00	ADS-XHE-OK-INHIB	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
		3.00E-04	NR-U1X-DEP-SRV	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.11E-02	RCI-TDP-FS-OP203	RCIC TDP FAILS TO START
8	1.20E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-BC421	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1BC421
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
9	1.20E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-BC422	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1BC422
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
10	1.20E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-BC652	UV CIRCUIT LOGIC FAULT IN PNL 1BC652
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)

Table B.1-3

TOP 10 CUTSETS FOR ΔCDF FOR THE EDG "B" OOS CASE
(PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

#	Cutset Prob	Event Prob	Event	Description
1	7.14E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		1.31E-02	DGS-DGN-FS-DG400	DIVISION D DIESEL 1DG400 FAILS TO START
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
2	2.68E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	DCP-XHE-PORTA	FAILURE TO CROSS TIE BUS TO BATTERY CHARGER PORTABLE SUPPLY
		1.31E-02	DGS-DGN-FS-DG400	DIVISION D DIESEL 1DG400 FAILS TO START
		1.39E-02	HPI-TDP-FS-OP204	HPCI TDP FAILS TO START
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
3	2.30E-07	1.00E-04	%IE-FIRE37	DG Room (D) Fire Scenario 5304_2
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
4	4.70E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		1.31E-02	DGS-DGN-FS-AG400	DIVISION A DIESEL 1AG400 FAILS TO START
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
5	4.67E-08	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		6.20E-02	CAC-XHE-FO-LVENT	LOCAL VENTING THRU 12" LINE FAILS
		1.30E-02	DGS-DGN-TM-AG400	DGS TRAIN AG400 IN TEST AND MAINT
		5.25E-02	LOOP-IE-SW	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		1.33E-01	OSPR20HR-SW	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
		3.50E-01	RHS-REPAIR-TR	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
6	1.82E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-DC421	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1DC421
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
7	1.82E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-DC422	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1DC422
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT

Table B.1-3

TOP 10 CUTSETS FOR ΔCDF FOR THE EDG "B" OOS CASE (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

#	Cutset Prob	Event Prob	Event	Description
8	1.82E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ACP-LOG-NO-DC652	UV CIRCUIT LOGIC FAULT IN PNL 1DC422
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
9	1.82E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		3.33E-03	ESF-LOG-NO-ELSD	FAULTS IN ELS TRAIN D LOGIC CIRCUIT
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR
		2.30E-03	RX-FWR-POR	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
10	1.63E-07	2.37E-02	%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT
		2.50E-02	DCP-EDG-PORTGEN	PORTABLE GENERATOR FAILS
		1.31E-02	DGS-DGN-FS-DG400	DIVISION D DIESEL 1DG400 FAILS TO START
		2.10E-02	NR-UV-WTLVL-20M	FAILURE TO CONTROL RPV WATER LVL W/HIGH PRESS. INJ. SYS.
		1.00E+00	NR-XTIE-EDG	FAILURE TO CROSS-TIE DIESEL GENERATOR

Table B.1-4

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION OF EDG "A" OOS CASE(1)
(PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
NR-XTIE-EDG	1.00E+00	9.85E-01	1	FAILURE TO CROSS-TIE DIESEL GENERATOR
LOOP-IE-SW	5.25E-02	2.49E-01	5.5	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
DCP-XHE-PORTA	6.20E-02	2.18E-01	4.29	FAILURE TO CROSS TIE BUS TO BATTERY CHARGER PORTABLE SUPPLY
ADS-XHE-OK-INHIB	1.00E+00	2.15E-01	1	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
LOOP-IE-GR	2.93E-01	2.11E-01	1.51	COND. PROBABILITY LOOP DUE TO GRID RELATED EVENT
OSPR4HR-GR	1.32E-01	1.64E-01	2.08	FAILURE TO RECOVER OSP WITHIN 4. 5 HRS (GRID RELATED LOOP EVENT)
LOOP-IE-SWYD	4.03E-01	1.53E-01	1.23	COND. PROBABILITY LOOP DUE TO SWYD EVENT
OSPR20HR-SW	1.33E-01	1.52E-01	1.99	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
DGS-DGN-FS-BG400	1.31E-02	1.44E-01	11.82	DIVISION B DIESEL 1BG400 FAILS TO START
DGS-DGN-FS-DG400	1.31E-02	1.40E-01	11.58	DIVISION D DIESEL 1DG400 FAILS TO START
NR-U1X-DEP-SRV	3.00E-04	1.36E-01	455.32	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.
CAC-XHE-FO-LVENT	6.20E-02	1.29E-01	2.96	LOCAL VENTING THRU 12" LINE FAILS
RPT-PIP-RP-SEALS	9.50E-01	1.18E-01	1.01	COND. PROB. OF SMALL RECIRC SEAL LOCA GIVEN SBO
RHS-REPAIR-TR	3.50E-01	1.15E-01	1.21	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
DGS-DGN-TM-BG400	1.30E-02	9.44E-02	8.16	DGS TRAIN BG400 IN TEST AND MAINT
IE-LOOP-CND-001	2.40E-03	9.31E-02	39.72	CONDITIONAL LOOP GIVEN TRANSIENT W/O LOCA SIGNAL
DGS-DGN-TM-DG400	1.30E-02	9.00E-02	7.83	DGS TRAIN DG400 IN TEST AND MAINT
DCP-EDG-PORTGEN	2.50E-02	8.82E-02	4.44	PORTABLE GENERATOR FAILS
NRHVCSWGR24-01	4.10E-03	8.36E-02	21.31	Fail to restore SWGR room cooling
OSPR4HR-SWYD	6.72E-02	8.20E-02	2.14	FAILURE TO RECOVER OSP WITHIN 4. 5 HRS (SWYD CENTERED LOOP EVENT)
XHOS-RIVER-GT80	1.20E-01	7.40E-02	1.54	RIVER TEMPERATURE IS GREATER THAN 80 F
SWS-MDP-TM-BP502	5.53E-02	6.55E-02	2.12	SWS PUMP TRAIN BP502 IN TEST AND MAINT
SWS-MDP-TM-CP502	5.53E-02	6.40E-02	2.09	SWS PUMP TRAIN CP502 IN TEST AND MAINT
OSPR7HR-GR	6.10E-02	6.31E-02	1.97	FAILURE TO RECOVER OSP WITHIN 7 HRS (SW RELATED LOOP EVENT)
RHR-XHE-RHR-INJ	1.00E-01	5.92E-02	1.53	FAILURE TO ALIGN RHR MOV 17B LOCALLY FOR INJECTION
OSPR4HR-SW	3.61E-01	5.65E-02	1.1	FAILURE TO RECOVER OFFSITE POWER WITHIN 4.5 HRS (SW RELATED EVENT)
XHOS-RIVER-LT70	6.90E-01	5.16E-02	1.02	RIVER TEMPERATURE IS LESS THAN 70 F

Table B.1-4

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION OF EDG "A" OOS CASE(1)
(PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
SAC-AOV-OO-2457B	1.11E-03	5.13E-02	47.2	VALVE 2457B FAILS TO CLOSE
SWS-XHE-FO-SACC1	4.40E-01	5.01E-02	1.06	CASE 1: COGNITIVE ERROR TO OPEN SACS/SSW HX VALVES (40 MIN. AVAIL)
OSPR20HR-GR	5.66E-03	4.57E-02	9.03	FAILURE TO RECOVER OSP WITHIN 20 HRS (GRID RELATED LOOP EVENT)
RX-FWR-ADS-POR	6.00E-06	4.34E-02	7.21E+03	DEP OP ACT: FAIL TO INITIATE ADS, FW CNTRL, AND INITIATE PORTABLE GENERATOR
IE-LOOP-CND-L	2.40E-02	4.04E-02	2.64	CONDITIONAL LOOP GIVEN TRANSIENT WITH LOCA SIGNAL
XHOS-STBY-DP502LT	5.00E-01	3.92E-02	1.04	PUMP SSW DP502 IN STANDBY WITH 2 PUMPS OPERATING
RCI-TDP-FS-OP203	1.11E-02	3.90E-02	4.47	RCIC TDP FAILS TO START
OSPR7HR-SW	2.80E-01	3.87E-02	1.1	FAILURE TO RECOVER OSP WITHIN 7 HRS (SW RELATED LOOP EVENT)
DGS-DGN-FS-CG400	1.31E-02	3.49E-02	3.63	DIVISION C DIESEL 1CG400 FAILS TO START
FPS-XHE-ALIGN	5.80E-02	3.35E-02	1.54	FAILURE TO ALIGN FPS FOR INJECTION IN TIME
OSPR7HR-SWYD	3.14E-02	3.27E-02	2.01	FAILURE TO RECOVER OSP WITHIN 7 HRS (SWYD CENTERED LOOP EVENT)
OSPR20HR-SWYD	3.51E-03	2.91E-02	9.27	FAILURE TO RECOVER OSP WITHIN 20 HRS (SWYD CENTERED LOOP EVENT)
RHS-REPAIR-L	4.30E-01	2.81E-02	1.04	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (LOCA EVENTS)
VIS-FAN-TM-CV503	2.38E-02	2.62E-02	2.07	VIS FAN TRAIN CV503 IN TEST AND MAINT
SAC-XHE-FO-HEAT	9.60E-03	2.57E-02	3.65	SACS HEAT LOAD MANIPULATION
DW-SHELL-RUPT	4.50E-01	2.55E-02	1.03	DRYWELL SHELL RUPTURE DISRUPTS INJECTION LINES AND FAILS RB SYS
RHS-MDP-TM-PB	1.58E-02	2.53E-02	2.58	RHS PUMP TRAIN B IN TEST AND MAINT
ACP-LOG-NO-BC421	3.33E-03	2.41E-02	8.21	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1BC421
ACP-LOG-NO-BC422	3.33E-03	2.41E-02	8.21	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1BC422
ACP-LOG-NO-BC652	3.33E-03	2.41E-02	8.21	UV CIRCUIT LOGIC FAULT IN PNL 1BC652
ESF-LOG-NO-ELSB	3.33E-03	2.40E-02	8.18	FAULTS IN ELS TRAIN B LOGIC CIRCUIT
SWS-MDP-TM-DP502	5.53E-02	2.31E-02	1.4	SWS PUMP TRAIN DP502 IN TEST AND MAINT
SWS-XHE-FO-71AC1	3.30E-01	2.19E-02	1.04	CASE 1 LOCAL MANUAL ACTION TO OPEN 2371A FAILS (40 MIN.)
VIS-FAN-TM-DV503	2.38E-02	2.18E-02	1.89	VIS FAN TRAIN DV503 IN TEST AND MAINT
RCI-MOV-LK-ROOM	1.00E-01	1.97E-02	1.18	PROBABILITY OF STEAM LEAK INTO RCI ROOM
ACP-LOG-NO-DC421	3.33E-03	1.95E-02	6.84	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1DC421
ACP-LOG-NO-DC422	3.33E-03	1.95E-02	6.84	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1DC422

Table B.1-4

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION OF EDG "A" OOS CASE(1)
(PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
ACP-LOG-NO-DC652	3.33E-03	1.95E-02	6.84	UV CIRCUIT LOGIC FAULT IN PNL 1DC422
ESF-LOG-NO-ELSD	3.33E-03	1.94E-02	6.81	FAULTS IN ELS TRAIN D LOGIC CIRCUIT
RX-HVAC-FPS	6.20E-04	1.89E-02	31.41	DEP HEP: FAILURE TO INITIATE HVAC AND FPS INJECTION WITH FIRE PUMPER
SWS-XHE-FO-71AC2	4.00E-02	1.86E-02	1.45	CASE 2 LOCAL MANUAL ACTION TO OPEN 2371A FAILS (154 MIN.)
ESF-XHE-MC-DF01	8.00E-05	1.75E-02	219.27	COMMON CAUSE MISCALIBRATION OF ALL ECCS PRESSURE TRANS.
LOOP-IE-PC	9.44E-02	1.72E-02	1.17	COND. PROBABILITY LOOP DUE TO PLANT CENTERED EVENT
ACP-XHE-MC-A0374	1.70E-03	1.62E-02	10.53	MISCALIBRATION OF UV SENSOR FOR UV RELAYING 1A 0374
ACP-XHE-MC-A0376	1.70E-03	1.62E-02	10.5	MISCALIBRATION OF UV SENSOR FOR UV RELAYING 1A 0376
DGS-XHE-MC-7530B	1.70E-03	1.61E-02	10.45	SDG B DAYTANK LEVEL CONTROL SWITCH LSHL7530B MISCAL
DGS-XHE-MC-7530D	1.70E-03	1.61E-02	10.43	SDG D DAYTANK LEVEL CONTROL SWITCH LSHL7530D MISCAL
VCA-FANB-FF-STBY	5.00E-01	1.40E-02	1.01	CONDITIONAL PROB. OF TRAIN B FAN AND CHILLER BEING IN STANDBY
XHOS-RIVER-70TO80	1.90E-01	1.38E-02	1.06	RIVER TEMPERATURE IS 70 TO 80 DEG F
XHOS-STBY-BP502LT	5.00E-01	1.26E-02	1.01	PUMP SSW BP502 IN STANDBY WITH 2 PUMPS OPERATING
CHC-MDP-TM-BP400	1.76E-02	1.24E-02	1.69	CHC PUMP TRAIN BP400 IN TEST AND MAINT
RPCDRPS-MECHFCC	2.10E-06	1.23E-02	5.80E+03	MECHANICAL SCRAM FAILURE
SWS-XHE-FO-START	7.50E-03	1.22E-02	2.61	FAILURE TO START SW PUMPS WHEN REQUIRED
NR-U1X-DEP-SET	1.00E-02	1.19E-02	2.18	FAILURE TO DEPRESSURIZE WITH SRV (SEISMIC)
HPI-TDP-FS-OP204	1.39E-02	1.16E-02	1.82	HPCI TDP FAILS TO START
PLSV-F-RECL-K--	1.50E-01	1.10E-02	1.06	FAILURE OF SRVS TO RECLOSE ON REDUCED PRESSURE
PLSVSORV-NTTK--	5.40E-02	1.10E-02	1.19	PROBABILITY OF SORV FOR ISOLATION INITIATORS
SAC-AOV-CC-2395D	1.11E-03	1.02E-02	10.21	SAC VALVE HV2395D FAILS TO OPEN
OSPR4HR-PC	4.03E-02	1.02E-02	1.24	FAILURE TO RECOVER OSP WITHIN 4. 5 HRS (PLANT CENTERED LOOP EVENT)
SAC-AOV-CC-2395B	1.11E-03	1.02E-02	10.19	SAC VALVE HV 2395B FAILS TO OPEN
HPI-MOV-LK-ROOM	1.00E-02	1.01E-02	2	PROBABILITY OF STEAM LEAK INTO HPI ROOM
OSPR30MIN-GR	8.25E-01	1.00E-02	1	FAILURE TO RECOVER GRID LOOP W/IN 30 MIN.
ADS-XHE-FO-COND	1.40E-01	9.84E-03	1.06	COND PROB OF MODERATE DEPEND BETWEEN INJECTION INITIATION & DEPRESS
NR-UV-ECCS-SET	3.90E-01	9.53E-03	1.01	FAILURE TO INITIATE ECCS DURING SEISMIC EVENT

Table B.1-4

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION OF EDG "A" OOS CASE(1)
(PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
FPS-PMP-DFP-FAIL	2.00E-02	9.45E-03	1.46	FAILURE OF THE DFP HARDWARE
FPS-TRK-FAIL	2.00E-02	9.45E-03	1.46	FAILURE OF THE FIRE PUMPER TRUCK HARDWARE
NRHVCSWGR24-SET	1.00E-01	9.30E-03	1.08	OPERATOR FAILS TO RESTORE SWITCHGEAR ROOM COOLING (SEISMIC)
SWS-MDP-FS-DP502	2.82E-03	8.82E-03	4.12	SWS PUMP DP-502 FAILS TO START
RAC-XHE-FO-2572A	1.30E-01	7.88E-03	1.05	OP FAILS TO ISOLATE WASTE EVAP CONDENSER
SWS-XHE-FO-SACC2	1.60E-02	7.84E-03	1.48	CASE 2: COGNITIVE ERROR TO OPEN SACS/SSW HX VALVES (154 MIN. AVAIL)
SLC-XHE-E-LVL	4.60E-01	7.59E-03	1.01	FAIL TO CONTROL LEVEL EARLY DURING ATWS SEQUENCE
XHOS-STBY-CP502LT	5.00E-01	7.43E-03	1.01	PUMP SSW CP502 IN STANDBY WITH 2 PUMPS OPERATING
XHOS-STBY-DP502GT	2.50E-01	7.29E-03	1.02	PUMP SSW DP502 IN STANDBY WITH 3 PUMPS OPERATING
SRV-TNK-LK-TRANS	1.00E-04	7.29E-03	73.86	FAILURE OF 13/14 ACCUMULATORS (LEAKAGE) (NON-SBO)
ACP-LOG-NO-CC421	3.33E-03	7.14E-03	3.14	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1CC421
ACP-LOG-NO-CC422	3.33E-03	7.14E-03	3.14	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1CC422
ACP-LOG-NO-CC652	3.33E-03	7.14E-03	3.14	UV CIRCUIT LOGIC FAULT IN PNL 1CC652
OSPR30MIN-SWYD	5.95E-01	7.10E-03	1	FAILURE TO RECOVER OSP WITHIN 30 MIN. (SWYD CENTERED EVENT)
RHS-STR-PL-PB	4.21E-03	7.04E-03	2.66	RHR SUCTION STRAINER B PLUGGED IN STANDBY
ESF-LOG-NO-ELSC	3.33E-03	7.02E-03	3.1	FAULTS IN ELS TRAIN C LOGIC CIRCUIT
RPT-PIP-RP-SEALL	5.00E-02	6.94E-03	1.13	COND. PROB. OF LARGE RECIRC SEAL LOCA GIVEN SBO
RHS-STR-PL-PD	8.36E-03	6.80E-03	1.81	RHR SUCTION STRAINER D PLUGGED IN STANDBY
ESF-XHE-MC-N050	2.00E-03	6.69E-03	4.34	MISCALIBRATION OF PRESSURE TRANSMITTER E51-N050
ESF-XHE-MC-N051	2.00E-03	6.69E-03	4.34	MISCALIBRATION OF FLOW TRANSMITTER E51-N051
NR-UV-WTLVL-SET	4.30E-01	6.67E-03	1.01	FAILURE TO CONTROL LEVEL WITH HPCI/RCIC (SEISMIC)
VIS-BDD-CC-D503B	3.00E-03	6.52E-03	3.17	DAMPER D503B FAILS TO OPEN (INTAKE)
VIS-BDD-CC-D504B	3.00E-03	6.52E-03	3.17	DAMPER D504B FAILS TO OPEN (EXHAUST)
RX-ADS-HVAC	1.62E-05	6.50E-03	401.79	DEP OP ACT: FAIL TO INITIATE ADS AND RESTORE SWGR COOLING
VIS-FAN-FS-BV503	2.89E-03	6.25E-03	3.15	FAN BV503 FAILS TO START
VIS-FAN-FS-BV504	2.89E-03	6.25E-03	3.15	FAN BV504 FAILS TO START
SWS-MDP-FS-BP502	2.82E-03	6.07E-03	3.15	SWS PUMP BP-502 FAILS TO START

Table B.1-4

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION OF EDG "A" OOS CASE[1] (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
SWS-MDP-FS-BP507	2.82E-03	6.07E-03	3.15	SWS-TWS PUMP BP-507 FAILS TO START
VIS-BDD-CC-D503C	3.00E-03	5.89E-03	2.96	DAMPER D503C FAILS TO OPEN (INTAKE)
VIS-BDD-CC-D504C	3.00E-03	5.89E-03	2.96	DAMPER D504C FAILS TO OPEN
VIS-BDD-OO-D503A	3.00E-03	5.89E-03	2.96	DAMPER D503A FAILS TO CLOSE
SAC-HDV-OO-DF02B	6.65E-05	5.87E-03	89.29	CCF FAILURE OF VALVES 2522B AND D TO TACS INLET LOOP
RCI-TDP-FR-OP203	1.75E-03	5.77E-03	4.29	RCIC TDP FAILS TO RUN (24 HR)
VIS-FAN-FR-BV503	2.66E-03	5.67E-03	3.13	FAN BV503 FAILS TO RUN
VIS-FAN-FR-BV504	2.66E-03	5.67E-03	3.13	FAN BV504 FAILS TO RUN
VIS-FAN-FS-CV503	2.89E-03	5.63E-03	2.94	FAN CV503 FAILS TO START
VIS-FAN-FS-CV504	2.89E-03	5.63E-03	2.94	FAN CV504 FAILS TO START
WW-DW-LK-RUPT	1.00E-01	5.53E-03	1.05	RB SYS FAIL DUE TO ENVRON. STRESS WW RUPT/LK
SWS-MDP-FS-CP502	2.82E-03	5.48E-03	2.94	SWS PUMP CP-502 FAILS TO START
SWS-MDP-FS-CP507	2.82E-03	5.48E-03	2.94	SWS-TWS PUMP CP-507 FAILS TO START
VIS-FAN-FR-CV503	2.66E-03	5.08E-03	2.9	FAN CV503 FAILS TO RUN
VIS-FAN-FR-CV504	2.66E-03	5.08E-03	2.9	FAN CV504 FAILS TO RUN

(1) Initiating Events have been deleted from this importance list.

Table B.1-5

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION FOR EDG "B" OOS (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
NR-XTIE-EDG	1.00E+00	9.81E-01	1	FAILURE TO CROSS-TIE DIESEL GENERATOR
RX-FWR-POR	2.30E-03	3.05E-01	133.17	DEP OP ACT: FAIL TO INITIATE FW CNTRL AND PORTABLE GENERATOR ALIGNMENT
DCP-XHE-PORTA	6.20E-02	2.72E-01	5.12	FAILURE TO CROSS TIE BUS TO BATTERY CHARGER PORTABLE SUPPLY
DGS-DGN-FS-DG400	1.31E-02	2.47E-01	19.62	DIVISION D DIESEL 1DG400 FAILS TO START
HPI-TDP-FS-OP204	1.39E-02	1.86E-01	14.19	HPCI TDP FAILS TO START
DCP-EDG-PORTGEN	2.50E-02	1.77E-01	7.92	PORTABLE GENERATOR FAILS
LOOP-IE-SW	5.25E-02	9.04E-02	2.63	COND. PROBABILITY DUE TO WEATHER RELATED LOOP EVENT
IE-LOOP-CND-001	2.40E-03	8.43E-02	36.05	CONDITIONAL LOOP GIVEN TRANSIENT W/O LOCA SIGNAL
LOOP-IE-GR	2.93E-01	7.93E-02	1.19	COND. PROBABILITY LOOP DUE TO GRID RELATED EVENT
NR-UV-WTLVL-20M	2.10E-02	6.96E-02	4.25	FAILURE TO CONTROL RPV WATER LVL W/HIGH PRESS. INJ. SYS.
ACP-LOG-NO-DC421	3.33E-03	6.19E-02	19.52	UV CIR LOG FLT IN LOCL GEN CNTRL PNL 1DC421
ACP-LOG-NO-DC422	3.33E-03	6.19E-02	19.52	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1DC422
ACP-LOG-NO-DC652	3.33E-03	6.19E-02	19.52	UV CIRCUIT LOGIC FAULT IN PNL 1DC422
ESF-LOG-NO-ELSD	3.33E-03	6.18E-02	19.49	FAULTS IN ELS TRAIN D LOGIC CIRCUIT
DGS-DGN-FS-AG400	1.31E-02	6.00E-02	5.52	DIVISION A DIESEL 1AG400 FAILS TO START
RPT-PIP-RP-SEALS	9.50E-01	5.75E-02	1	COND. PROB. OF SMALL RECIRC SEAL LOCA GIVEN SBO
LOOP-IE-SWYD	4.03E-01	5.73E-02	1.08	COND. PROBABILITY LOOP DUE TO SWYD EVENT
OSPR4HR-GR	1.32E-01	5.40E-02	1.35	FAILURE TO RECOVER OSP WITHIN 4. 5 HRS (GRID RELATED LOOP EVENT)
OSPR20HR-SW	1.33E-01	5.20E-02	1.34	FAILURE TO RECOVER OSP WITHIN 20 HRS (SW RELATED LOOP EVENT)
ADS-XHE-OK-INHIB	1.00E+00	4.44E-02	1	OPERATOR SUCCESSFULLY INHIBITS ADS WITH NO HP INJECTION (NON-ATWS)
DGS-DGN-TM-AG400	1.30E-02	4.23E-02	4.21	DGS TRAIN AG400 IN TEST AND MAINT
NRHVCSWGR24-01	4.10E-03	3.79E-02	10.2	Fail to restore SWGR room cooling
NR-U1X-DEP-SRV	3.00E-04	3.22E-02	108.12	FAILURE TO DEPRESSURIZE WITH SRV W/O HIGH PRES. INJ.
DGS-DGN-FS-CG400	1.31E-02	3.21E-02	3.42	DIVISION C DIESEL 1CG400 FAILS TO START
ACP-XHE-MC-A0376	1.70E-03	3.13E-02	19.4	MISCALIBRATION OF UV SENSOR FOR UV RELAYING 1A 0376
DGS-XHE-MC-7530D	1.70E-03	3.12E-02	19.34	SDG D DAYTANK LEVEL CONTROL SWITCH LSHL7530D MISCAL

Table B.1-5

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION FOR EDG "B" OOS (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
OSPR7HR-GR	6.10E-02	3.06E-02	1.47	FAILURE TO RECOVER OSP WITHIN 7 HRS (SW RELATED LOOP EVENT)
XHOS-RIVER-GT80	1.20E-01	2.90E-02	1.21	RIVER TEMPERATURE IS GREATER THAN 80 F
RHR-XHE-RHR-INJ	1.00E-01	2.87E-02	1.26	FAILURE TO ALIGN RHR MOV 17B LOCALLY FOR INJECTION
CAC-XHE-FO-LVENT	6.20E-02	2.83E-02	1.43	LOCAL VENTING THRU 12" LINE FAILS
OSPR4HR-SWYD	6.72E-02	2.73E-02	1.38	FAILURE TO RECOVER OSP WITHIN 4. 5 HRS (SWYD CENTERED LOOP EVENT)
RHS-REPAIR-TR	3.50E-01	2.72E-02	1.05	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (TRANSIENT EVENTS)
SWS-MDP-TM-AP502	5.53E-02	2.56E-02	1.44	SWS PUMP TRAIN AP502 IN TEST AND MAINT
IE-LOOP-CND-L	2.40E-02	2.47E-02	2	CONDITIONAL LOOP GIVEN TRANSIENT WITH LOCA SIGNAL
SWS-MDP-TM-CP502	5.53E-02	2.44E-02	1.42	SWS PUMP TRAIN CP502 IN TEST AND MAINT
SWS-XHE-FO-SACC1	4.40E-01	2.36E-02	1.03	CASE 1: COGNITIVE ERROR TO OPEN SACS/SSW HX VALVES (40 MIN. AVAIL)
HPI-TDP-FR-OP204	1.75E-03	2.25E-02	13.85	HPCI TDP FAILS TO RUN (24 HR)
XHOS-RIVER-LT70	6.90E-01	2.10E-02	1.01	RIVER TEMPERATURE IS LESS THAN 70 F
SAC-AOV-CC-2395D	1.11E-03	2.03E-02	19.3	SAC VALVE HV2395D FAILS TO OPEN
RCI-MOV-LK-ROOM	1.00E-01	2.01E-02	1.18	PROBABILITY OF STEAM LEAK INTO RCI ROOM
HPI-HDV-CC-4879	1.51E-03	1.98E-02	14.07	VALVE 4879 FAILS TO OPEN
HPI-HDV-CC-4880	1.51E-03	1.98E-02	14.07	VALVE 4880 FAILS TO OPEN
XHOS-STBY-DP502LT	5.00E-01	1.92E-02	1.02	PUMP SSW DP502 IN STANDBY WITH 2 PUMPS OPERATING
OSPR4HR-SW	3.61E-01	1.87E-02	1.03	FAILURE TO RECOVER OFFSITE POWER WITHIN 4.5 HRS (SW RELATED EVENT)
OSPR7HR-SW	2.80E-01	1.85E-02	1.05	FAILURE TO RECOVER OSP WITHIN 7 HRS (SW RELATED LOOP EVENT)
SAC-AOV-OO-2457A	1.11E-03	1.71E-02	16.41	VALVE HV-2457A FAILS TO CLOSE
DGS-DGN-TM-CG400	1.30E-02	1.71E-02	2.3	DGS TRAIN CG400 IN TEST AND MAINT
VIS-FAN-TM-DV503	2.38E-02	1.62E-02	1.66	VIS FAN TRAIN DV503 IN TEST AND MAINT
OSPR7HR-SWYD	3.14E-02	1.57E-02	1.48	FAILURE TO RECOVER OSP WITHIN 7 HRS (SWYD CENTERED LOOP EVENT)
OSPR20HR-GR	5.66E-03	1.56E-02	3.73	FAILURE TO RECOVER OSP WITHIN 20 HRS (GRID RELATED LOOP EVENT)
FPS-XHE-ALIGN	5.80E-02	1.54E-02	1.25	FAILURE TO ALIGN FPS FOR INJECTION IN TIME
SAC-XHE-FO-HEAT	9.60E-03	1.47E-02	2.51	SACS HEAT LOAD MANIPULATION
SWS-MDP-TM-DP502	5.53E-02	1.44E-02	1.25	SWS PUMP TRAIN DP502 IN TEST AND MAINT
HPI-MOV-CC-F001	1.07E-03	1.40E-02	14.02	MOV HV-F001 FAILS TO OPEN
HPI-MOV-CC-F012	1.07E-03	1.40E-02	14.02	MOV HVF012 FAILS TO OPEN

Table B.1-5

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION FOR EDG "B" OOS (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
HPI-MOV-OO-F012	1.07E-03	1.40E-02	14.02	MIN-FLOW MOV HVF012 FAILS TO CLOSE
NR-UV-WTLVL-SET	4.30E-01	1.04E-02	1.01	FAILURE TO CONTROL LEVEL WITH HPCI/RCIC (SEISMIC)
ACP-INV-NO-DD481	5.52E-04	9.96E-03	19.04	LOSS INV OUTPUT DUE TO MISC MECH FLTS- 1DD481
ACP-INV-NO-DD482	5.52E-04	9.95E-03	19.03	LOSS INV OUTPUT DUE TO MISC MECH FLTS- 1DD482
OSPR20HR-SWYD	3.51E-03	9.81E-03	3.79	FAILURE TO RECOVER OSP WITHIN 20 HRS (SWYD CENTERED LOOP EVENT)
ACP-BKR-OO-40407	5.00E-04	9.02E-03	19.04	BKR 52-40407 FAILS TO CLOSE
ACP-BKR-CC-40401	5.00E-04	9.02E-03	19.03	BKR 52-40401 FAILS TO OPEN
ACP-BKR-CC-40408	5.00E-04	9.02E-03	19.03	BKR 52-40408 FAILS TO OPEN
DGS-DGN-FR-DG400	4.91E-04	8.85E-03	19.04	DIVISION D DIESEL 1DG400 FAILS TO RUN
RHS-STR-PL-PD	8.36E-03	8.70E-03	2.03	RHR SUCTION STRAINER D PLUGGED IN STANDBY
RX-HVAC-FPS	6.20E-04	8.44E-03	14.6	DEP HEP: FAILURE TO INITIATE HVAC AND FPS INJECTION WITH FIRE PUMPER
RHS-MDP-TM-PD	1.58E-02	8.33E-03	1.52	RHS PUMP TRAIN D IN TEST AND MAINT
ACP-LOG-NO-AC421	3.33E-03	7.55E-03	3.26	UV CIRC LOG FLT IN LOCL GEN CNTRL PNL 1AC421
ACP-LOG-NO-AC422	3.33E-03	7.55E-03	3.26	UV CIRC LOG FLT IN REM GEN CNTRL PNL 1AC422
ACP-LOG-NO-AC652	3.33E-03	7.55E-03	3.26	UV CIRCUIT LOGIC UNIT FAULT IN PNL 1AC652
ESF-LOG-NO-ELSA	3.33E-03	7.50E-03	3.25	FAULTS IN ELS TRAIN A LOGIC CIRCUIT
RHS-REPAIR-L	4.30E-01	7.12E-03	1.01	REPAIR/RECOVERY OF RHR FOR LOSS OF DHR EVENTS (LOCA EVENTS)
ACP-XHE-MC-A0373	1.70E-03	6.71E-03	4.94	MISCALIBRATION OF UV SENSOR FOR UV RELAYING 1A 0373
DGS-XHE-MC-7530A	1.70E-03	6.65E-03	4.9	SDC A DAYTANK LEVEL CONTROL SWITCH LSHL7530A MISCAL
ESF-XHE-MC-DF01	8.00E-05	6.55E-03	82.83	COMMON CAUSE MISCALIBRATION OF ALL ECCS PRESSURE TRANS.
%IE-FIRE28	1.25E-05	6.53E-03	522.17	Cmprtmnt 5339 Fire Scenario 5339_2
DGS-FLT-PL-DF405	3.60E-04	6.46E-03	18.94	SDG D FUEL PUMP DISC FILTER DF405 PLUGGED IN STANDBY
VCA-FANA-FF-STBY	5.00E-01	6.27E-03	1.01	CONDITIONAL PROB. OF TRAIN A FAN AND CHILLER BEING IN STANDBY
VIS-FAN-TM-CV503	2.38E-02	6.24E-03	1.26	VIS FAN TRAIN CV503 IN TEST AND MAINT
LOOP-IE-PC	9.44E-02	6.21E-03	1.06	COND. PROBABILITY LOOP DUE TO PLANT CENTERED EVENT
SWS-XHE-FO-START	7.50E-03	5.85E-03	1.77	FAILURE TO START SW PUMPS WHEN REQUIRED
OSPR30MIN-GR	8.25E-01	5.84E-03	1	FAILURE TO RECOVER GRID LOOP W/IN 30 MIN.
XHOS-RIVER-70TO80	1.90E-01	5.81E-03	1.02	RIVER TEMPERATURE IS 70 TO 80 DEG F

Table B.1-5

BASIC EVENT CONTRIBUTORS FOR THE ΔCDF EVALUATION FOR EDG "B" OOS (PRA EVALUATION OF INTERNAL AND EXTERNAL EVENTS FOR APPLICATION MODEL WITH COMPENSATORY MEASURES 3-6)

Event Name	Probability	Fussell-Vesely	Risk Achievement Worth	Description
CHC-MDP-TM-AP400	1.76E-02	5.56E-03	1.31	CHC PUMP TRAIN AP400 IN TEST AND MAINT

(1) *Initiating Events have been deleted from this importance list.*

B.2 ASSESSMENT OF UNCERTAINTY

As discussed earlier, epistemic uncertainty is generally categorized into three types -- parameter, model, and completeness uncertainty. These are each discussed in the sections which follow.

B.2.1 Parameter Uncertainty

The cutset results for the different delta-CDF assessments were reviewed to determine if the epistemic correlation could influence the mean value determination. From the review of the cutsets, it was determined that the dominant contributing cutsets do not involve basic events with epistemic correlations (i.e., the probabilities of multiple basic events within the same cutset for the dominant contributors are not determined from a common parameter value). Per Guideline 2b from EPRI 1016737 [B-1], then it is acceptable to use the point estimate directly in the risk assessment.

To verify that the use of the point estimate is acceptable in these four cases, a detailed Monte Carlo calculation using EPRI R&R workstation UNCERT software was performed to compare the mean value determined from the Monte Carlo simulation as compared to the point estimate. The results of those assessments are provided in Tables B.2-1A and B.2-1B below. Figures displaying the probability density function for all of the cases appear after the table. Based on the minimal difference in the comparison of the mean value with the point estimate values provided, the use of the point estimate for this assessment is deemed acceptable.

Note that a similar assessment is performed for the LERF figure of merit and the trend is similar. That is, the parametric mean values are very close to the point estimate mean values. The use of the point estimate is deemed acceptable.

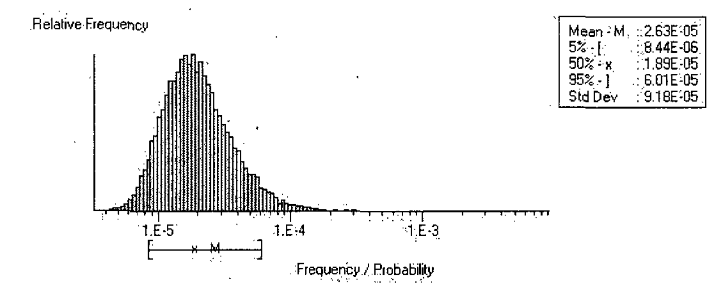
Table B.2-1A

CDF PARAMETRIC UNCERTAINTY EVALUATIONS AND COMPARISON TO POINT ESTIMATE RESULTS

Result	HCGS	
	EDG "A" Case	EDG "B" Case
Propagated Mean Values[(1)]		
CDF_X[(1)]	2.63E-5/yr	3.10E-5/yr
CDF_{BASE}[(1)]	2.25E-5/yr	
$\Delta CDF^{(1)} = CDF_X - CDF_{BASE}$	**3.84E-6/yr**	**8.50E-6/yr**
Point Estimate Values[(2)]		
CDF_X[(2)]	2.44E-6/yr	2.89E-5/yr
CDF_{BASE}[(2)]	2.18E-05/yr	
$\Delta CDF^{(2)} = CDF_X - CDF_{BASE}$	**2.60E-6/yr**	**7.10E-7/yr**

(1) Developed based on the parametric mean value for each case from a Monte Carlo simulation with 15,000 samples.

(2) Developed based on the point estimate value for each case.



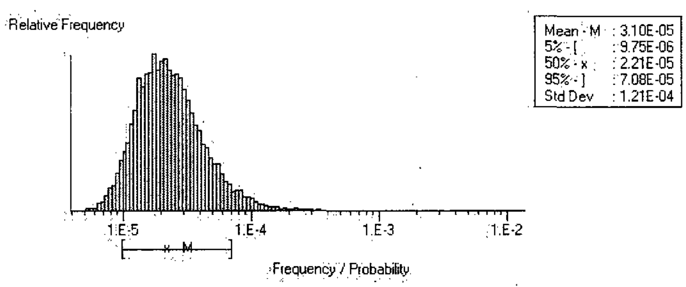


Figure B.2-1A EDG "A" and "B" Cases for Uncertainty Distribution of CDF

Table B.2-1B

LERF PARAMETRIC UNCERTAINTY EVALUATIONS AND COMPARISON TO POINT ESTIMATE RESULTS

Result	HCGS	
	EDG "A" Case	EDG "B" Case
Propagated Mean Values(1)		
$LERF_X$(1)	7.99E-7/yr	1.72E-6/yr
$LERF_{BASE}$(1)	8.18E-7/yr	
ΔLERF(1) = $LERF_X$ - $LERF_{BASE}$	**ε**	**9.0E-7/yr**
Point Estimate Values(2)		
$LERF_X$(2)	7.91E-7/yr	1.70E-6/yr
$LERF_{BASE}$(2)	7.91E-7/yr	
ΔLERF(2) = $LERF_X$ - $LERF_{BASE}$	**ε**	**9.1E-7/yr**

(1) Developed based on the parametric mean value for each case from a Monte Carlo simulation with 15,000 samples.

(2) Developed based on the point estimate value for each case.

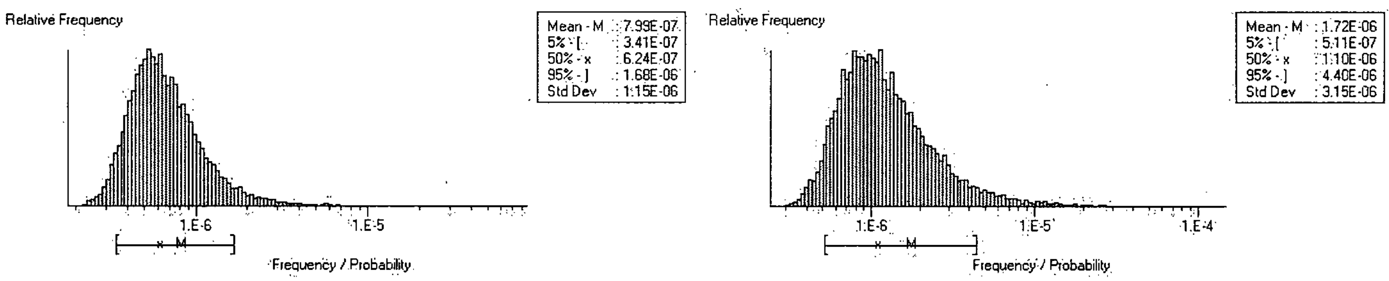


Figure B.2-1B EDG "A" and "B" Cases for Uncertainty Distribution of LERF

B.2.2 Model Uncertainty

The assessment of model uncertainty utilizes the guidance provided in EPRI 1016737 [B-1] and in NUREG-1855 [B-2] and considers the following:

1. Characterize the manner in which the PRA model is used in the application
2. Characterize modifications to the PRA model
3. Identify application-specific contributors
4. Assess sources of model uncertainty in the context of important contributors
    a. Also consider other sources of model uncertainty from the base PRA model assessment for the identification of candidate key sources of uncertainty
    b. Screen based on relevance to parts of PRA needed or based on relevance to the results
5. Identify sources of model uncertainty and related assumptions relevant to the application
    a. This involves the formulation of sensitivity studies for those sources of uncertainty that may challenge the acceptance guidelines and an interpretation of the results

Appendix F provides the implementation of NUREG-1855 to identify the candidate sources of model uncertainty for the internal events PRA. Modeling uncertainties derived from the external events analysis are discussed in Appendix A and Appendix B.1. Appendix B.1 also provides insights into the plant specific and application specific modeling uncertainties that may have the largest impact on the risk metrics.

B.2.2.1 Characterize the Manner in which the PRA Model is Used in the Application

The manner in which the PRA model is used in this application is fully described in Section 3 and will not be reproduced here.

B.2.2.2 Characterize Modifications to the PRA Model

There are no specific changes made to the model that introduce any application-specific sources of model uncertainty.

It is noted that one change to the base model has been included to remove credit for the Salem Unit 3 Gas Turbine. This results in slightly higher calculated risk metric compared with using the model of record (MOR).

B.2.2.3 Identify Application-Specific Contributors

This plant specific search focused on a review of plant design and an in-depth review of the cutsets that contribute to the delta-risk associated with an EDG OOS condition. Section B.1 and Appendix D provide these plant specific insights.

Table B.2-2 provides a review of the events that are identified in Appendix B.1 that may be included in a modeling uncertainty assessment.

Based on the detailed assessment provided in Section B.1, the following items are the important contributors to the change compared to the base case results:

- LOOP initiating event
- Operator Actions ensuring proper standby alignment of the companion EDG train in the same mechanical division would reduce risk
- Operator Actions for the use of the portable battery charger to support DC power supply until AC recovery can be established and to align FPS to RPV injection
- HPCI reliability and availability
- SW and SACS reliability and test and maintenance unavailability
- EDG Reliability

The results of the application specific assessment in Appendix B.1 are dominated by internal event contributors. This result is consistent with the breakdown in Table B.1-1. Nonetheless, this list of potential uncertainties is augmented by a review of the seismic and fire analysis in Appendix A. This augmented review indicates that it is prudent to include modeling uncertainties associated with the fire and seismic initiating events.

This evaluation provides input into the assessment of key model uncertainties in Section B.3.

B.2.2.4 Assess Sources of Model Uncertainty in Context of Important Contributors

A review of the identified sources of model uncertainty from the base model assessment as identified by implementing the process outlined in EPRI 1016737 for Hope Creek is then performed to determine which of those items are potentially applicable for this assessment even though they did not appear as a dominant contributor in the base assessment for the application. Based on this review, some of the items are already identified and many of the items are easily screened, but the following items are added for investigation since they are judged to be potentially applicable for this application.

Generic Modeling Uncertainties

- LOOP frequency
- ISLOCA frequency
- HEPs and Dependent HEPs
- Common Cause Failure probabilities

External Events

The external event evaluations also have potential uncertainties that may influence the decision makers in their evaluation of the EDG A and B AOT extension.

The sensitivity cases that are judged prudent to perform to highlight these effects on the EDG A and B AOT extension include the following:

- Vary the seismic initiating frequencies to establish the uncertainty in using the EPRI seismic hazard curve versus the LLNL revised seismic hazard curve.
- Vary the fire initiating event frequencies from those developed in the IPEEE to those in the 2003 NRC fire initiating events database.

Assessment of Potential Candidate Uncertainties for EDG AOT Application

Based on the identified important contributors as summarized in Section B.2.2.3 and the addition of applicable base PRA model sources of uncertainty identified in Section B.2.2.4, the next step is to perform a qualitative assessment to determine if sources of uncertainty have been utilized in the PRA that affect the important contributors for the application.

A qualitative assessment is then provided for each of the previously identified important contributors or potential sources of uncertainty to determine if they would result in exceeding the acceptance guidelines from any single basic event. The results of this assessment are shown in Table B.2-3..

B.2.3 Completeness Uncertainty

The calculations performed to support the EDG AOT extension include the following hazard groups:

- Internal events
- Internal flood
- Fire
- Seismic

Other external events were previously screened from consideration in the IPEEE.

Shutdown risk is not quantified, however, it is judged that moving the EDG overhauls from the refuel outages to on-line will reduce the shutdown risk contribution to the overall risk.

Table B.2-2

SUMMARY OF SCREENING OF SENSITIVITY CASES

Important Events		Proposed Uncertainty Treatment
Designator	Event Description	
NR-XTIE-EDG RPT-PIP-RPSEALS ADS-XHE-OK-INHIB	Failure to cross-tie diesel generator to other AC divisions. Cond. Prob. of small recirc seal LOCA given SBO. Op. successfully inhibits ADS.	Probabilities already assigned as high failure probabilities. Uncertainty in these events is not a contributor to higher application specific risk metrics.
DCP-XHE-PORTA DCP-EDG-PORTGEN	Portable Generator Reliability and Alignment.	Sensitivity cases on HEP and reliability are possible.
DGS-DGN-FS-DG400 DGS-DGN-FS-AG400 DGS-DGN-TM-AG400 DGS-DGN-FS-CG400 DGS-XHE-MC-7530D DGS-DGN-TM-CG400 DGS-DGN-FR-DG400	'D' EDG Reliability A and C EDG T&M and reliability.	Reliability and unavailabilities are to be included for sensitivity.
LOOP-IE-SW IE-LOOP-CND-001 LOOP-IE-GR OSPR7HR-GR LOOP-IE-SWYD OSPR4HR-SWYD IE-LOOP-CND-L OSPR4HR-SW OSPR7HR-SW OSPR7HR-SWYD OSPR20HR-GR OSPR20HR-SWYD OSPR30MIN-GR	Offsite AC power related probabilities including non-recoveries.	These LOOP events are treated within a surrogate sensitivity on the LOOP initiating event frequency.

Table B.2-2

SUMMARY OF SCREENING OF SENSITIVITY CASES

Important Events		Proposed Uncertainty Treatment
Designator	Event Description	
Operator Actions	Operator Actions	Sensitivity Case Assigned for HEPs.
SWS-MDP-TM-AP502 SWS-MDP-TM-CP502 SWS-XHE-FO-SACC1 SAC-AOV-CC-2395D SAC-AOV-OO-2457A SAC-XHE-FO-HEAT SWS-MDP-TM-DP502 SWS-XHE-FO-START	SW and SAC Reliability (Some HEPs which are treated in HEP sensitivity)	RAW values are quite low and sensitivities are not expected to be contributors to the application specific risk metrics.
%IE-FIRE28	Fire Initiating Event	Fire initiating events are included in sensitivity.
HPI-TDP-FS-OP204 HPI-TDP-FR-OP204 HPI-HDV-CC-4879 HPI-HDV-CC-4880 HPI-MOV-CC-F001 HPI-MOV-CC-F012 HPI-MOV-OO-F012	HPCI Reliability events	HPCI reliability could be a significant contributor to model uncertainty.

Table B.2-3

IDENTIFICATION OF POTENTIAL KEY SOURCES UNCERTAINTY DERIVED FROM

Source of Uncertainty	Source of Model Uncertainty for Base Model	Application Important Contributor	Source of Model Uncertainty Assessment	Potential Key Source of Uncertainty
Seismic Initiating Event Frequency	Yes (Appendix A)	Possible	The seismic hazard function may vary significantly depending on the assumptions used in its construction	Yes - retain for sensitivity.
Fire Initiating Event Frequency	Yes (Appendix A)	Possible	Fire initiating event frequencies and their attendant severity have trended to lower frequencies as operating experience and fire prevention actions are taken.	Yes - retain for sensitivity.
Specific EDG Maintenance Configurations	No (Appendix B.1)	Yes	The relative importance of the maintenance terms for the EDGs that directly support the remaining equipment trains indicates that avoiding maintenance on these EDGs during the extended AOT could be a potentially important action that could be taken to reduce the risk associated with the extended AOT.	Yes – but addressed with proposed compensatory measures.
LOOP Frequency	Yes (Appendix F and Appendix B.1)	Yes	Uncertainty in the LOOP frequency and recovery probabilities will lead to some change in the calculated delta-risk since LOOP scenarios comprise approximately 80-85% of the calculated ΔCDF in all cases, but the overall assessment is not limited to only LOOP events. However, the LOOP initiating event frequency and fail to recover values are fairly well accepted (being based on NUREG-6890). The assessment led to an increase of CDF sufficient to cause exceedance of ICCDP, and as such the LOOP initiating events are retained as a potential key source of uncertainty.	Yes

Table B.2-3

IDENTIFICATION OF POTENTIAL KEY SOURCES UNCERTAINTY DERIVED FROM

Source of Uncertainty	Source of Model Uncertainty for Base Model	Application Important Contributor	Source of Model Uncertainty Assessment	Potential Key Source of Uncertainty
ISLOCA frequencies	Yes (Appendix F)	No	The ISLOCA frequency leading to core damage is unaffected by the EDG OOS. In addition, the ISLOCA frequencies for Hope Creek are derived from a detailed ISLOCA analysis which includes the relevant considerations listed in IE-C12 of the ASME/ANS PRA Standard and accounts for common cause failures and captures likelihood of different piping failure modes. While the ISLOCA frequency and the internal flooding analysis are important uncertainties to be aware of in the base model, these frequencies are not direct contributors to the change in risk for the EDG AOT extension and the calculation of the risk metrics(ΔCDF, ΔLERF, ICCDP, and ICLERP) for the EDG AOT extension application. Given these three attributes, the ISLOCA frequencies are not identified as a potential key source of uncertainty.	No
Human Error Probability Values Dependent Human Error Probability Values	Yes (NUREG-1855)	Yes	The HRA was performed using a systematic approach that is consistent with the ASME PRA Standard and has been peer reviewed. One of the requirements of the standard is that the HEPs be compared as a set to ensure that the ranking is appropriate to the context within which HEP is evaluated. The identification of significant contributors discussed in Section B.1 resulted in the identification of the most significant human failure events.	Yes – treat as part of HEP development as a class

Table B.2-3

IDENTIFICATION OF POTENTIAL KEY SOURCES UNCERTAINTY DERIVED FROM

Source of Uncertainty	Source of Model Uncertainty for Base Model	Application Important Contributor	Source of Model Uncertainty Assessment	Potential Key Source of Uncertainty
Common Cause Failure Values	Yes (NUREG-1855)	No	Due to the nature of the EDG LAR with the evaluation of one EDG out of service, the change in the risk metrics is not materially affected by additional single failures and as such CCF values do not play a big role in the risk assessment. A sensitivity examining the possible changes in the common cause failure probabilities is not included in the EDG AOT extension risk assessment. This decision is based on an examination of the importance measures of the delta-CDF cutsets for the EDG "B" OOS compared with the Base Case when the Compensatory Measures 3-6 are included in the model. This review of the importance measures identifies that the common cause terms do not show up for RAW values above 1.2. Therefore, it is not identified as a potential key source of uncertainty for this application.	No
Diesel generator reliability	Yes (Appendix B.1)	Yes	A sensitivity examining the possible changes in the common cause failure probabilities is not included in the EDG AOT extension risk assessment. This decision is based on an examination of the importance measures of the delta-CDF cutsets for the EDG "B" OOS compared with the Base Case when the Compensatory Measures 3-6 are included in the model. This review of the importance measures identifies that the common cause terms do not show up for RAW values above 1.2.	Yes

Table B.2-3

IDENTIFICATION OF POTENTIAL KEY SOURCES UNCERTAINTY DERIVED FROM

Source of Uncertainty	Source of Model Uncertainty for Base Model	Application Important Contributor	Source of Model Uncertainty Assessment	Potential Key Source of Uncertainty
Portable DC Generator	Yes (Appendix B.1)	Yes	The portable generator is modeled to extend the time available with DC power for operation of RCIC, HPCI, SRVs, and AC power restoration. Operator action and hardware failures are included in the model. Conservative estimates are used in both the crew response and reliability.	Yes - but there is minimal credit assigned to this safe shutdown path, i.e., it is conservatively treated in both the base model and the application model.
HPCI Reliability	Yes (Appendix B.1)	Yes	The data for HPCI reliability is based on generic prior and Bayesian updated with plant specific evidence. No degrading trend of HPCI reliability is noted.	No
SW and SACS Reliability and T&M	Yes (Appendix B.1)	Yes	The SW and SACS reliability is relatively high and large changes would be required to affect the risk metrics. The T&M coincident with EDG OOS is part of the Compensatory Measures	No

B.3 SENSITIVITY CASES TO ADDRESS POTENTIAL UNCERTAINTIES

Based on the evaluation of important contributors shown in Table B.2-3, several sensitivity cases are prepared for further exploration. Other potential key sources of uncertainty are screened or already identified as being addressed with potential compensatory measures.

The quantitative sensitivity calculations that are performed to address this application are the following:

- Vary the seismic initiating frequencies to establish the uncertainty in using the EPRI seismic hazard curve versus the LLNL revised seismic hazard curve
- Vary the fire initiating event frequencies from those developed in the IPEEE to those in the 2003 NRC fire initiating events database
- LOOP initiating event frequency
- EDG unavailability sensitivity
- HEP sensitivity
- EDG Reliability sensitivity
- Portable generator reliability
- HPCI reliability

The sensitivity cases are performed by applying the model changes to both the "base case" evaluation and the EDG Out Of Service (OOS) case. This allows the impact of the new modeling assumption to be examined in a consistent fashion. All sensitivity cases are performed assuming that the Compensatory Measures 3 through 6 are implemented.

B.3.1 <u>Seismic Hazard Sensitivity</u>

This subsection addresses the potential uncertainty associated with varying assumptions regarding the seismic hazard curve. This subsection compares the risk metrics for the proposed EDG A and B AOT extension when the LLNL seismic hazard curve is used in lieu of the EPRI seismic hazard curve.

This sensitivity case is prudent to perform to examine the use of the LLNL revised seismic hazard curves and its impact on decision making. This modeling difference represents an uncertainty in the modeling of the seismic hazard function. The sensitivity evaluation is useful to assess both the quantitative impact on the calculated risk metrics and qualitatively if any new insights are derived from the seismic cutsets.

Sensitivity Case

Replace the EPRI hazard curve function convoluted with the system failures with the comparable LLNL seismic hazard function as identified in Table B.3-1.

Table B.3-2 provides a summary of the risk metrics for the limiting case of the EDG "B" OOS with Compensatory Measures 3 through 6 incorporated.

Results

As can be seen from Table B.3-2, the risk metrics all remain within the acceptance guidelines from both RG 1.174 and RG 1.177 despite the significant change in the seismic hazard curves.

Table B.3-1

COMPARISON OF THE SEISMIC HAZARD FUNCTION FOR EPRI AND LLNL

Initiator[1]	Frequency (/yr)	
	LLNL Hazard Curve	EPRI Hazard Curve
%IE-SET02	1.80E-07	7.90E-08
%IE-SET03	6.00E-07	4.40E-07
%IE-SET04	6.90E-09	2.70E-09
%IE-SET05	4.00E-07	2.60E-07
%IE-SET06	6.10E-09	3.60E-09
%IE-SET07	1.90E-08	7.40E-09
%IE-SET09	8.10E-07	4.40E-07
%IE-SET10	2.00E-08	5.00E-09
%IE-SET11	5.80E-08	1.90E-08
%IE-SET13	6.10E-08	2.70E-08
%IE-SET15	1.10E-08	1.80E-09
%IE-SET18	6.30E-05	5.90E-05
%IE-SET19	5.40E-07	1.60E-07
%IE-SET20	1.60E-06	6.40E-07
%IE-SET21	6.90E-08	9.90E-09
%IE-SET22	1.40E-06	4.40E-07
%IE-SET23	8.20E-08	1.20E-08
%IE-SET24	2.30E-07	3.70E-08
%IE-SET25	2.40E-08	1.60E-09
%IE-SET26	3.80E-06	1.10E-06
%IE-SET27	2.40E-07	3.40E-08
%IE-SET28	6.70E-07	1.00E-07
%IE-SET29	6.80E-08	4.70E-09
%IE-SET30	8.10E-07	1.00E-07
%IE-SET31	9.80E-07	6.40E-09
%IE-SET32	2.50E-07	1.70E-08
%IE-SET33	3.90E-08	1.10E-09
%IE-SET34	4.60E-08	3.70E-09
%IE-SET35	1.60E-07	4.60E-08
%IE-SET36	2.50E-06	6.70E-07
%IE-SET37	4.40E-07	5.50E-08
%IE-SET38	5.40E-08	2.10E-08

(1) Refer to Appendix A for a description of these seismic "initiators".

Table B.3-2

COMPARISON OF RISK METRICS BETWEEN THE EPRI SEISMIC HAZARD CURVE AND THE LLNL SEISMIC HAZARD CURVE FOR EDG "B" OOS (PRA QUANTIFICATION INCLUDES INTERNAL AND EXTERNAL EVENTS)

Risk Metric	Base Case: EPRI Hazard Curve	Upper Bound: LLNL Hazard Curve	Acceptance Guideline
ΔCDF	1.94E-07	2.8E-07	1.0E-6(1)
ΔLERF	1.81E-08	1.82E-08	1.0E-7(1)
ICCDP	2.72E-07	3.61E-07	<5E-07(2)
ICLERP	3.49E-08	3.49E-08	<5E-08(2)

(1) Region III of RG 1.174.

(2) RG 1.177.

B.3.2 Sensitivity Case for Fire Initiating Events

This subsection addresses the potential uncertainty associated with varying assumptions regarding the fire ignition frequencies. This subsection compares the risk metrics for the proposed EDG A and B AOT extension when the fire ignition frequencies using very old data is used in lieu of data reflecting more recent trends in Nuclear Power Plants.

This sensitivity case is prudent to perform to examine the use of the fire data and its impact on decision making. This modeling difference represents an uncertainty in the modeling of the fire accident sequences. The sensitivity evaluation is useful to assess both the quantitative impact on the calculated risk metrics and qualitatively if any new insights are derived from the fire cutsets.

Sensitivity Case

Replace the 2003 NRC Fire Event Database with the much older fire data used in the Hope Creek IPEEE.

Table B.3-3 provides a summary of the risk metrics for the limiting case of the EDG "B" OOS with Compensatory Measures 3 through 6 incorporated.

Results

As can be seen from Table B.3-3, the risk metrics all remain within the acceptance guidelines from both RG 1.174 and RG 1.177 despite the significant change in the fire ignition frequencies with the exception of ICCDP.

Table B.3-3

SUMMARY OF SENSITIVITY CASE FOR FIRE IGNITION FREQUENCIES

Risk Metric	Upper Bound Fire Ignition Frequency Sensitivity Case	Acceptance Guideline
ΔCDF	8.20E-7	1.0E-6[1]
ΔLERF	3.04E-8	1.0E-7[1]
ICCDP	7.10E-7	<5E-07[2]
ICLERP	4.87E-8	<5E-08[2]

B.3.3 Sensitivity of LOOP Initiating Event Frequency

The LOOP frequency is derived from the data analysis provided in NUREG/CR-6890 by causal factor. These are updated using Hope Creek specific data.

The upper bound on the LOOP frequency is calculated by the Bayesian analysis. Using the calculated range factor of 8.0 leads to a 95% upper bound of 8.51E-02/yr for the LOOP frequency.

Sensitivity Case

Using this extreme estimate of the LOOP frequency in the EDG AOT evaluation, Table B.3-4 summarizes the resulting risk metrics.

Table B.3-4
SUMMARY OF SENSITIVITY CASE FOR LOOP INITIATING EVENT FREQUENCY

Risk Metric	Upper Bound LOOP Initiating Event Sensitivity Case	Acceptance Guideline
ΔCDF	6.12E-7	1E-6
ΔLERF	5.39E-8	1E-7
ICCDP	8.44E-7	<5E-7
ICLERP	1.04E-7	<5E-8

Results

As expected with the use of such an extreme assumption, the ICCDP and ICLERP exceed their acceptance guidelines. Nevertheless, it is judged that while this extreme sensitivity case provides an additional input into the decision making process, it is appropriately treated by the Compensatory Measures and the PSEG intention to minimize these configurations by protecting against configurations coincident with the potential for severe weather.

B.3.4 EDG Unavailability Sensitivity

A potential sensitivity evaluation is to consider whether the addition of the extended AOT would be completely additive to the existing EDG unavailability time.

Sensitivity

To explore this sensitivity, the ΔCDF_{AVE} and $\Delta LERF_{AVE}$ are recalculated assuming that the EDG A and B unavailabilities are increased from their current levels to the following:

EDG	Assumed Unavailability Insensitivity Case
EDG A	2E-2 + 1.3E-2 = 3.3E-2
EDG B	2E-2 + 1.3E-2 = 3.3E-2
EDG C	1.3E-2
EDG D	1.3E-2

The ICCDP and ICLERP for the "B" EDG are quoted here because the "B" EDG is the most limiting of the two EDGs.

See Table 3.4-6 for the current EDG unavailability estimates.

Results

The results of this sensitivity case including Compensatory Measures 3 through 6 are shown in Table B.3-5.

Table B.3-5

SUMMARY OF SENSITIVITY CASE FOR EDG UNAVAILABILITY

Risk Metric	Application Model	Upper Bound Sensitivity Case	Acceptance Guideline
ΔCDF_{AVE}	1.94E-07/yr	2.06E-07/yr	1E-06/yr
$\Delta LERF_{AVE}$	1.81E-08/yr	1.76E-08/yr	1E-07/yr
$ICCDP_{B\text{-}EDG}$	2.72E-07	No Change	5E-07/yr
$ICLERP_{B\text{-}EDG}$	3.49E-08	No Change	5E-08/yr

EDG "C" and "D" already have an approved Technical Specification change for a AOT of 14 days. Table 3.4-6 shows that HCGS operating experience indicates that the C and D maintenance unavailabilities are essentially the same as those for EDGs "A" and "B". This reinforces the fact that the extended AOT will not be abused and that the treatment of the observed unavailability compared with the extended AOT may be an artificial distinction.

Therefore, while this represents a useful sensitivity, as can be seen by examining the EDG C and D unavailabilities, it is judged not to represent the CDF increase because the total extended AOT will not be used and the 24 month PM will incorporate or prevent outages that might otherwise occur.

The difference in the risk metrics is very small by including the AOT as an incremental increase over and above the historical average EDG unavailability, i.e., the ΔCDF and ΔLERF change by a negligible amount.

B.3.5 HEP Sensitivity

One sensitivity case involves the Human Error Probability (HEP) development as a class.

Sensitivity

For this sensitivity study, all post-initiator HEP events are set to their 95th percentile values. This resulted in independent and dependent HEPs that are multiplied by factors in the range of 2 to 4 to approximate the 95% upper bound HEPs. While this range is smaller than that which could be obtained by using a totally different HRA approach, it is sufficient, in this case, to demonstrate that the HEP values are a potential key source of uncertainty.

Results

The inputs for this sensitivity case are presented in Table B.3-6 with the corresponding output parameters for comparison to the acceptance guidelines shown in Table B.3-7.

Table B.3-6

HEP SENSITIVITY CASE RISK ASSESSMENT INPUT PARAMETERS

Input Parameter	Application Model Inputs (Base Case)	Upper Bound Sensitivity Case Inputs 95th HEP Value
CDF_{BASE} (/yr)	2.18E-05	4.92E-05
CDF_A (/yr)	2.44E-05	5.58E-05
CDF_B (/yr)	2.89E-05	6.43E-05
T_A	14 Days	14 Days
T_B	14 Days	14 Days
T_{CYCLE}	700 Days	700 Days
AOT_{NEW} (/yr)	3.84E-02	3.84E-02

Table B.3-7

HEP SENSITIVITY CASE RISK ASSESSMENT OUTPUT RESULTS

Risk Metric	Application Model (Base Case)	Upper Bound Sensitivity Case 95th HEP Value	Acceptance Guideline
ΔCDF (/yr)	1.94E-07	4.34E-07	<1E-06
ΔLERF (/yr)	1.81E-08	6.56E-08	<1E-07
$ICCDP_B$	2.72E-07	5.79E-07	<5E-07
$ICLERP_B$	3.49E-08	8.36E-08	<5E-08

Human Error Probability Values

- A substantial fraction of the CDF and LERF base case cutsets include human error terms as contributors.
- Correspondingly, setting all of the HEP values to their 95th percentile values increases the CDF by a factor of 2.3 and LERF by a factor of 1.5.
- However, both CDF and LERF remain below the RG 1.174 CDF and LERF acceptance guideline of 1×10^{-4}/yr for CDF and 1×10^{-5}/yr for LERF even when all of the independent and dependent HEP values are set to their 95th percentile values.
- The ΔCDF and ΔLERF is below the Region III acceptance guideline for RG 1.174.

As expected, the results of the sensitivity case show that significant changes to the HEPs have a profound impact on the calculated risk metrics. The increase in the CDF values when the 95th percentile (upper bound) HEP values are utilized is relatively large. These results are similar to most BWR PRA uncertainty evaluations when this sensitivity case is performed and is not unexpected. Additionally, a review of importance measures from the delete term cutsets between the EDG A or B cases and the revised base case (i.e., with all HEPs set at their 95th percentile value) indicated that the same set of operator actions would be identified as most important. In this sensitivity case, however, they become even more important from a relative risk perspective. This sensitivity case result reinforces the conclusion that the modeling and quantification of crew response actions under accident conditions is an important uncertainty in the assessment of risk.

B.3.6 Diesel Generator Failure Rate

There is some uncertainty regarding the EDG reliability that could influence the associated risk metrics for the EDG A and B AOT extension request.

Sensitivity

This sensitivity case is aimed at examining the risk metrics when the EDG failure to start and failure to run probabilities are placed at their 95% upper bound.

Results

The results for the EDG reliability sensitivity case are shown in Table B.3-8.

All acceptance guidelines except the ICLERP are met at the 95% upper bound. ICLERP only slightly exceeds the ICLERP acceptance guideline.

Table B.3-8

SUMMARY OF SENSITIVITY RESULTS FOR EDG FTR AND FTS SET AT 95% UPPER BOUND

Risk Metric	Upper Bound EDG Reliability Sensitivity Case	Acceptance Guidelines
ΔCDF	2.74E-7	1E-6
ΔLERF	2.60E-8	1E-7
ICCDP	4.07E-7	<5E-7
ICLERP	5.06E-8	<5E-8

B.3.7 Portable DC Generator Alignment

One of the alternate methods of safe shutdown given an extended SBO event is the use of the portable battery charger to extend the time available for AC power restoration.

Sensitivity

The sensitivity is to take the already conservative assessment of the alignment action and use the approximate 95% upper bound to form a sensitivity case.

Results

The results of the sensitivity are provided in Table B.3-9.

Table B.3-9

SUMMARY OF SENSITIVITY RESULTS FOR PORTABLE GENERATOR ALIGNMENT SET AT 95% UPPER BOUND

Risk Metric	Upper Bound EDG Reliability Sensitivity Case	Acceptance Guidelines
ΔCDF	2.70E-7	1E-6
ΔLERF	1.86E-8	1E-7
ICCDP	3.84E-7	<5E-7
ICLERP	3.59E-8	<5E-8

B.3.8 HPCI Failure Rate

There is some uncertainty regarding the HPCI reliability that could influence the associated risk metrics for the EDG A and B AOT extension request. It is noted that there are no indications of degraded HPCI performance at Hope Creek.

Sensitivity

This sensitivity case is aimed at examining the risk metrics when the HPCI failure to start probability is placed at its 95% upper bound.

Results

The results for the HPCI reliability sensitivity case are shown in Table B.3-10. All Regulatory Guide Acceptance Guidelines are met for this upper bound evaluation

Table B.3-10

SUMMARY OF SENSITIVITY RESULTS FOR HPCI FTS SET AT 95% UPPER BOUND

Risk Metric	Upper Bound EDG Reliability Sensitivity Case	Acceptance Guidelines
ΔCDF	2.30E-7	1E-6
ΔLERF	2.52E-8	1E-7
ICCDP	3.45E-7	<5E-7
ICLERP	4.86E-8	<5E-8

B.3.9 Summary

A series of sensitivity cases are performed to highlight possible variations in results derived from modeling uncertainties. The HCGS sensitivity evaluations are performed by examining the change in risk metrics for these 95% upper bound sensitivities with the Compensatory Measures 3 through 6 incorporated in the calculations. It is true that for RG 1.174 comparisons that the ordered pair of (CDF, ΔCDF) and (LERF, ΔLERF) are necessary to be examined to properly place the sensitivity case on the RG 1.174 two dimensional acceptance guideline. However, the changes postulated for the sensitivity cases are all with CDF l ess than 1E-4/yr and LERF less than 1E-5/yr and all within Region III.

As noted by NUREG-1855, the use of these initial conservative screening sensitivities reported in Section B.3 may lead to exceeding the acceptance guidelines. Table B.3-11 identifies several of the sensitivity cases that have one or more of the acceptance guidelines exceeded.

Section 5 of NUREG-1855 identifies that realistic sensitivity options for alternate models should be used in determining whether a modeling uncertainty is a key modeling uncertainty. Therefore, Appendix B.4 provides this additional step in the NUREG-1855 process.

Table B.3-11

SENSITIVITY CASE RESULTS USING UPPER BOUND CHARACTERIZATION

Sensitivity Case	Description	Change in Model	ΔCDF_{AVE} (/yr)	$\Delta LERF_{AVE}$ (/yr)	ICCDP[(1)]	ICLERP[(1)]
0	Base Case	---	1.94E-07	1.81E-08	2.72E-07	3.49E-08
B.3.1	Use of LLNL Seismic Hazard	Modified Seismic IE	2.8E-07	1.82E-08	3.61E-07	3.49E-08
B.3.2	Use of More Conservative Fire Initiating Event Frequency	Modify Fire IE	8.20E-07	3.04E-08	7.10E-07[(5)]	4.87E-08
B.3.3	LOOP Initiating Event Frequency	Modify LOOP IE	6.12E-07	5.39E-08	8.44E-07[(2)]	1.04E-07[(2)]
B.3.4	EDG Unavailability Sensitivity	Add EDG AOT to Historical Data	2.06E-07	1.76E-08	2.72E-07	3.49E-08
B.3.5	Post-Initiator HEPs set at 95% Upper Bound	Modify all Post-Initiator HEPs	4.34E-07	6.56E-08	5.79E-07[(3)]	8.36E-08[(3)]
B.3.6	Diesel Generator Failure Rate set at 95% Upper Bound	Modify FTS and FTR for EDG	2.74E-07	2.60E-08	4.07E-07	5.06E-08[(4)]
B.3.7	Portable DC Generator Alignment	Modify Alignment HEP for Generator	2.70E-07	1.86E-08	3.84E-07	3.59E-08
B.3.8	HPCI Reliability	Modify HPCI TDP FTS	2.30E-07	2.52E-08	3.45E-07	4.86E-08

(1) For the purposes of this summary table, the ICCDP and ICLERP are presented for the EDG "B" out of service (OOS). This is because the EDG "A" risk metrics are not as limiting as the EDG "B" risk metrics.

(2) Extreme Initiating Event frequencies could lead to exceeding the mean estimate acceptance guideline for ICCDP and ICLERP.

(3) Extreme 95% upper bound HEPs lead to exceeding the acceptance guideline for the mean results.

(4) Extreme 95% upper bound estimates on EDG unreliability leads to exceeding the mean estimate acceptance guidelines for ICLERP.

(5) Higher Fire Ignition frequencies lead to one of the mean estimate acceptance guidelines being exceeded (ICCDP).

B.4 REASONABLE SENSITIVITY CASE DEFINTIONS

Following the guidance in Section 5 of NUREG-1855, it is incumbent upon the analyst to characterize the degree of confidence in the assumptions associated with the sources of uncertainty that lead to the base case results (with compensatory measures incorporated) being within the acceptance guidelines. It is not the intent of this process to say that the results of any one or more sensitivity case being above the acceptance guidelines should automatically lead to a negative outcome by the decision maker. On the contrary, the intent of the process is to clearly identify those sources of uncertainty that are key to the decision (and therefore by definition will challenge the acceptance guidelines), and that appropriate compensatory measures have been identified to implement or otherwise deal with the key sources of uncertainty.

From Table B.3-10, the following sensitivities based on a conservative characterization of input variables result in exceeding one or more of the Regulatory Guideline acceptance guidelines:

- Fire Initiating Event Frequencies (ICCDP)
- LOOP Initiating Event Frequency (ICCDP and ICLERP)
- HEP quantification (ICCDP and ICLERP)
- EDG Failure to Run and Failure to Start (ICLERP)

The following specific qualitative insights from the Risk Management Team form the basis for a more reasonable uncertainty band to use in assessing those sensitivity cases which exceed the acceptance guidelines when using the conservative screening inputs:

- Fire Ignition Frequency:
  - Higher fire ignition frequencies are not considered representative of trends at nuclear plants.
  - The higher fire ignition frequencies are judged to be unrealistically high.

  - Current trends at nuclear plants indicate that fire ignition frequencies are even lower than assumed in the base case.
- LOOP Initiating Event Frequency:
  - The upper bound LOOP initiating event frequency is judged to be significantly higher than can be anticipated for Hope Creek. One of the compensatory measures addresses the severe weather portion of the LOOP frequency.
- HEPs:
  - One purpose of the HEP sensitivity is to confirm that a systematic bias in the HRA process is not suppressing an important insight; that is, the purpose of setting all of the HEPs to the 95th percentile value at the same time is to see if some additional actions should be separately identified as important.

    The conclusion for the EDG AOT extension sensitivity case is that an examination of the important contributors from the sensitivity case did not identify any new insights or indicate that there are any more compensatory measures that should be considered.
  - From a reasonable point of view, the HEPs used in the conservative screening sensitivity of Appendix B.3 are too high. A more reasonable assessment of the range of HEPs is judged to be appropriate as quantitative input to the decision makers.
- EDG Unreliability:
  - There is no evidence of degraded EDG performance at Hope Creek.
  - The extended AOT is proposed to <u>improve</u> EDG reliability.

  Therefore, the upper bound sensitivity case is not considered appropriate.

A more refined assessment of the conservative modeling of sensitivity cases in Appendix B.3 has led to defining more reasonable variations in the input parameters to provide more appropriate quantitative inputs to decision makers.

The more reasonable inputs to the sensitivity analysis are provided in Table B.4-1. These adjustments to the inputs are based on the above qualitative insights from the Risk Management Team.

The realistic and reasonable sensitivity analyses for these modeling issues yield results that are within the acceptance guidelines as shown in Table B.4-2. This step is consistent with Section 5 of NUREG-1855.

Table B.4-1

COMPARISON OF UPPER BOUND VERSUS REASONABLE INPUTS TO SENSITIVITY EVALUATIONS

Uncertainty	Conservative Screening Inputs	Realistic And Reasonable Sensitivity Inputs
Fire Ignition Frequency	Use of old Fire Ignition Data	Increase base Fire Initiators by 50%
LOOP Initiating Event Frequency	Set at 95% upper bound	Increase LOOP Initiator Frequency by 50% over mean
HEP Sensitivity	All at 95% upper bound	Increase HEPs by 50% over mean
EDG Unreliability	FTR, FTS at 95% upper bound	Set FTR at 95% upper bound(1)

(1) The failure of run (FTR) probability for diesel generators is subject to uncertainty due to the more limited data on long run time operation of the diesels. Therefore, for a more reasonable sensitivity case, the failure to run probability is maintained at its 95% upper bound. However, because there is no trend for degrading performance of the Hope Creek diesel generators and the failure to start probability is frequently tested, the failure to start probability can be retained as given in the base PRA for this reasonable sensitivity assessment.

Table B.4-2

REASONABLE SENSITIVITY CASE RESULTS

Sensitivity Case	Description	Change in Model	ΔCDF_{AVE} (/yr)	$\Delta LERF_{AVE}$ (/yr)	ICCDP(1)	ICLERP(1)
0	Base Case	---	1.94E-07	1.81E-08	2.72E-07	3.49E-08
B.4.1	Use of More Conservative Fire Initiating Event Frequency set at 50% higher	Modify Fire IE	3.18E-07	1.97E-08	3.87E-07	3.73E-08
B.4.2	LOOP Initiating Event Frequency set at 50% higher	Modify LOOP IE	2.72E-07	2.51E-08	3.80E-07	4.82E-08
B.4.3	Post-Initiator HEPs set at 50% higher	Modify all Post-Initiator HEPs	4.12E-07	2.05E-08	4.99E-07	3.85E-08
B.4.4	Diesel Generator Failure Rate set at 95% Upper Bound (FTR)	Modify FTR for EDG	1.96E-07	1.25E-08	2.76E-07	2.41E-08

(1) For the purposes of this summary table, the ICCDP and ICLERP are presented for the EDG "B" out of service (OOS). This is because the EDG "A" risk metrics are not as limiting as the EDG "B" risk metrics.

B.5 UNCERTAINTY ANALYSIS CONCLUSIONS

As previously indicated, the uncertainty analysis addresses the three generally accepted forms of uncertainty - parameter, model, and completeness uncertainty. The conclusions from these assessments are as follows.

Parameter Uncertainty

The parameter uncertainty assessment indicated that the use of the point estimate results directly for this assessment is acceptable.

Model Uncertainty

The model uncertainty assessment highlighted the following sources of uncertainty as being important to address with potential compensatory measures:

- Heightened awareness should be maintained regarding the important operator actions associated with the performance of the extended AOT.
- Proper standby alignment of the EDG supporting the same mechanical division should be ensured prior to entry into the AOT as this would reduce the contribution from potential pre-initiator errors.
- Besides the protected EDG trains, elective maintenance should be avoided.

Conservatisms in Modeling

There are a significant number of slight conservatisms that are incorporated into the model. The more realistic treatment of the conservatisms is expected to minimize the impact on risk metrics associated with the extreme bounding calculations identified in the sensitivity evaluations.

Completeness Uncertainty

There is no major form of completeness uncertainty that would impact the results of this assessment.

REFERENCES

[B-1] *Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments*, EPRI Report 1016737, Palo Alto, CA, December 2008.

[B-2] USNRC, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking," NUREG-1855, March 2009.

Appendix C

NOT USED

Appendix D

RISK SIGNIFICANT CONFIGURATIONS (TIER 2)

Appendix D

RISK SIGNIFICANT CONFIGURATIONS (TIER 2)

Regulatory Guide 1.177 provides the expectation that as part of the evaluation process for extending Allowed Outage Times (AOT) that a review of the risk significant plant configurations that may occur during the AOT be performed. RG 1.177 refers to this as the Tier 2 evaluation.

The following Tier 2 evaluation is aimed at identifying the at-power risk significant configurations when the A or B EDG is in an outage. The process used is to examine those additional components or trains whose unavailability would substantially increase the risk incurred during the EDG outage.

The Tier 2 evaluation is performed by examining the highest RAW basic events that are present in the delta-risk cutsets. The delta-risk cutsets are those that are derived by setting the EDG that is out of service (OOS) to TRUE in the logic model and deleting all of the cutsets that lead to failure (e.g., CDF or LERF) from the base model. These resulting delta-risk cutsets then indicate the basic events that are most "important" in increasing the risk for the EDG OOS configuration.

This search for adverse configurations leads to the identification of possible configuration specific actions that might be taken to ensure these adverse risk configurations do not inordinately contribute to any risk increase. These actions might be part of the Hope Creek CRMP. The investigation of the importance measures is performed on the delta-risk cutsets and examining the high RAW basic events.

Because this is an evaluation to examine configuration dependent risk synergies, the following basic events are not included in the detailed disposition:

- Initiators (Initiating Event contributions to the risk profile are evaluated separately (see Section 3)[1]. The results of that investigation identified LOOP initiators as the single largest potential contributor to the change in risk. LOOP prevention is a critically important contributor to be managed and is already identified with a potential compensatory measure.)
- HEPs (Crew actions in response to a LOOP or SBO are expected to be part of the shift briefings during an extended EDG AOT.)
- Phenomenological events (these can generally not be controlled)
- Common cause terms (These common cause dependencies have limited configuration dependence based on a review of cutsets.)

Table D-1 lists the basic events developed from this process ranked by Risk Achievement Worth (RAW). In addition, Table D-1 provides possible methods of controlling configuration risk associated with the extended EDG AOT. The review is based on the most limiting EDG being OOS (i.e., EDG B).

It is also found that the LERF contributors are essentially identical to the CDF contributors in Table D-1. Therefore, a separate evaluation of the LERF contributors is unnecessary.

The configuration specific actions to be discussed (no quantitative credit taken or expected in the PRA):

- Minimize switchyard work during EDG OOS
- Testing of breakers could be considered. This is judged to introduce significant competing risks.
- Testing of EDG could be considered. This is judged to introduce significant competing risks particularly for EDG preventive maintenance AOT.
- Verify battery voltage on the opposite 125V DC Division in the same mechanical division. Depending on the nature of this process and its intrusion into battery operability, it also could introduce competing risks.

(1) The LOOP frequency evaluation has been performed using the LOOP approach from NUREG/CR-6890 and it includes the insights of the August 2003 Northeast Blackout as they affect Hope Creek.

- Test SACS valve 2457A for the EDG OOS outage. Depending on this process, it could introduce competing risks.
- Prestage, test, and train on the alignment of the DC portable generator. This has the potential to further decrease the delta risk metrics, the ICCDP, and the ICLERP. However, this may be resource intensive.

Conclusion

The review of the risk significant configurations has identified six additional compensatory actions that could be considered as part of the EDG AOT extension. None of these actions are currently credited in the risk assessment, nor are any of these actions necessary to meet the acceptance guidelines for RG 1.177 and 1.174.

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
ACP-SPE-VF-500KV	1.00E-05	1.90E-03	191.14	500KV SWITCHYARD FAILS DUE TO VARIOUS FAULTS	Minimize work in the switchyard during EDG OOS
PNL-TSW-FT-SRVS	1.00E-08	4.07E-07	41.71	MANUAL SWITCH STATIONS FOR 13/14 SRVS FAIL.	This CCF probability is judged to be sufficiently low such that this failure mode is not a significant consideration.
SAC-AOV-CC-2395D	1.11E-03	2.04E-02	19.38	SAC VALVE HV2395D FAILS TO OPEN	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3) with EDG B OOS.
ACP-INV-NO-DD481	5.52E-04	1.00E-02	19.12	LOSS INV OUTPUT DUE TO MISC MECH FLTS- 1DD481	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3). In addition, compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
ACP-BKR-OO-40407	5.00E-04	9.07E-03	19.12	BKR 52-40407 FAILS TO CLOSE	Test Breaker prior to taking EDG OOS
DGS-DGN-FR-DG400	4.91E-04	8.89E-03	19.12	DIVISION D DIESEL 1DG400 FAILS TO RUN	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3) with EDG B OOS.
ACP-BKR-CC-40401	5.00E-04	9.06E-03	19.12	BKR 52-40401 FAILS TO OPEN; EDG SUPPLY BREAKER TO BUS 10A404 (DIV D)	Test Breaker prior to taking EDG OOS.
ACP-BKR-CC-40408	5.00E-04	9.06E-03	19.12	BKR 52-40408 FAILS TO OPEN; EDG SUPPLY BREAKER TO BUS 10A404 (DIV D)	Test Breaker prior to taking EDG OOS.

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
ACP-INV-NO-DD482	5.52E-04	1.00E-02	19.11	LOSS INV OUTPUT DUE TO MISC MECH FLTS- 1DD482	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3). In addition, compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
DGS-FLT-PL-DF405	3.60E-04	6.49E-03	19.02	SDG D FUEL PUMP DISC FILTER DF405 PLUGGED IN STANDBY	Clean Filter Prior to taking EDG OOS.
DGS-STR-PL-DF406	1.80E-04	3.21E-03	18.82	SDG D FUEL PMP SUCT STRNR DF406 PLUGGED IN STANDBY	Clean Strainer Prior to taking EDG OOS.
ACP-INV-FR-DD481	1.27E-04	2.23E-03	18.62	INVERTER FOR 1DD481 FAILS TO RUN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
ACP-INV-FR-DD482	1.27E-04	2.23E-03	18.61	INVERTER FOR 1DD482 FAILS TO RUN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
ACP-INV-TM-DD482	2.15E-04	3.73E-03	18.36	INVERTER 1DD482 UNAVAILABLE DUE TO TEST AND MAINT	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3) with EDG B OOS.
ACP-INV-TM-DD481	2.15E-04	3.70E-03	18.19	INVERTER 1DD481 UNAVAILABLE DUE TO TEST AND MAINT	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3) with EDG B OOS.
ACP-BAC-TM-1A404	1.19E-04	2.03E-03	18.06	4160V BUS 10A404 IN TEST AND MAINT (DIVISION D)	Do not place bus in maintenance coincident with EDG maintenance(1). Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3) with EDG B OOS.

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
ACP-BKR-CO-40410	2.40E-05	4.08E-04	17.98	BREAKER 52-40410 TRANSFERS OPEN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(2), (5)].
ACP-BKR-CO-44021	2.40E-05	4.08E-04	17.98	BREAKER 52-44021 TRANSFERS OPEN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
DCP-BKR-CO-44023	2.40E-05	4.08E-04	17.98	BREAKER 72-44023 TRANSFERS OPEN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
ACP-TFM-LP-DX400	2.17E-05	3.68E-04	17.95	FAILURE OF XFMR 1DX-400 LOSS OF POWER	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
VDG-FAN-TM-412DH	2.30E-05	3.90E-04	17.93	VDG FAN TRAINS 412D AND 412H IN TEST AND MAINT	Do not place fans in maintenance coincident with EDG maintenance[(1)].
ACP-BAC-ST-1A404	1.04E-05	1.72E-04	17.54	BUS 10A404 DIV D BUS FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
ACP-BAC-ST-1B440	1.04E-05	1.72E-04	17.54	1E USS BUS 10B440-DIV D FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
ACP-BAC-ST-1B441	1.04E-05	1.72E-04	17.54	1E DIV D 480 VAC MCC 10D441 FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].
DCP-BDC-ST-1D440	1.04E-05	1.72E-04	17.54	125 VDC BUS 10D440-DIV D FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[(3)].

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
DCP-BAT-ST-DD411	7.44E-06	1.21E-04	17.29	125VDC BAT 1DD411-DIV D FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
DCP-BAT-TM-DD411	6.30E-06	1.02E-04	17.17	125 VDC BAT 1DD411 DIV D - IN TEST AND MAINT	Compensatory measures already address the need to not remove Div D EDG or its support systems from service(3). (Verify battery voltage prior to taking EDG OOS)
DCP-FUS-OP-DD412	2.00E-06	3.08E-05	16.42	FUSE BLWN IN FUSE SWTCH BOX 1DD412-125VDC D	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
SAC-AOV-OO-2457A	1.11E-03	1.66E-02	15.97	VALVE HV-2457A FAILS TO CLOSE	Test valve prior to taking EDG OOS.
HPI-TDP-FS-OP204	1.39E-02	1.87E-01	14.25	HPCI TDP FAILS TO START	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-HDV-CC-4879	1.51E-03	1.99E-02	14.13	VALVE 4879 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-HDV-CC-4880	1.51E-03	1.99E-02	14.13	VALVE 4880 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-CC-F001	1.07E-03	1.40E-02	14.08	MOV HV-F001 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-CC-F012	1.07E-03	1.40E-02	14.08	MOV HVF012 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-OO-F012	1.07E-03	1.40E-02	14.08	MIN-FLOW MOV HVF012 FAILS TO CLOSE	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-TDP-FR-OP204	1.75E-03	2.26E-02	13.9	HPCI TDP FAILS TO RUN (24 HR)	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
CNS-CKV-OO-F032A	1.04E-04	1.32E-03	13.65	HPCI CKV F032A ALLOWS BACK FLOW	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
DCP-CHG-NO-1D423	1.22E-04	1.54E-03	13.61	250 VDC BAT CHGR 10D423 SHORT AND MISC FAULTS	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4). Verify battery voltage prior to taking EDG OOS.
ACP-BKR-CO-41021	2.40E-05	2.93E-04	13.22	BREAKER 52-41021 TRANSFERS OPEN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
DCP-BKR-CO-45014	2.40E-05	2.93E-04	13.22	BREAKER 72-45014 TRANSFERS OPEN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
HPI-CKV-CC-V003	1.30E-05	1.56E-04	13.03	CHECK VALVE V003 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-CKV-CC-V004	1.30E-05	1.56E-04	13.03	CHECK VALVE V004 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-CKV-CC-V015	1.30E-05	1.56E-04	13.03	MIN-FLOW CHECK VALVE V015 FAILS TO OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
ACP-BAC-ST-1B411	1.04E-05	1.25E-04	13.01	1E DIV A 480 VAC MCC 10B411 FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(2), (5).
DCP-BDC-ST-1D251	1.04E-05	1.25E-04	13.01	250VDC MCC BUS 10D251-DIV A FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
DCP-BDC-ST-1D450	1.04E-05	1.25E-04	13.01	250 VDC BUS 10D450-DIV A FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
DCP-BAT-ST-1D421	7.44E-06	8.75E-05	12.76	250VDC BAT 10D421-DIV A FAILURE SHORTS	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
HPI-TDP-TM-HP-RC	2.30E-05	2.68E-04	12.66	COINCIDENT TRAIN UNAVAILABILITY DUE TO EMERGENT WORK HPCI & RCIC	Confirms that the compensatory measure to ensure HPCI and RCIC are not OOS is appropriate(4).
DCP-BAT-TM-1D421	6.30E-06	7.35E-05	12.66	250 VDC BAT 10D421 DIV A - IN TEST AND MAINT	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3). Already realistically addressed. This represents a negligible decrease in risk if further improved.
DCP-FUS-OP-1D422	2.00E-06	2.18E-05	11.92	FUSE BLWN IN FUSE SWTCH BOX 10D422-250VDC A	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
DCP-CHG-TM-1D423	1.39E-06	1.49E-05	11.7	250 VDC BAT CHGR 10D423 DIV A - IN TEST AND MAINT	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).
HPI-MOV-OC-F002	1.07E-06	1.08E-05	11.14	N.O. MOV HV-F002 FAILS TO REMAIN OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-OC-F003	1.07E-06	1.08E-05	11.14	N.O. MOV HV-F003 FAILS TO REMAIN OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-OC-F007	1.07E-06	1.08E-05	11.14	N.O. MOV HV-F007 FAILS TO REMAIN OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
HPI-MOV-OC-F071	1.07E-06	1.08E-05	11.14	N.O. MOV HV-F071 FAILS TO REMAIN OPEN	Confirms that the compensatory measure to ensure HPCI is not OOS is appropriate(4).
ACP-INV-NO-AD481	5.52E-04	4.97E-03	10.01	LOSS INV OUTPUT DUE TO MISC MECH FLTS- 1AD481	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS(3).

Table D-1

EXAMINATION OF HIGHEST IMPORTANCE BASIC EVENTS TO THE DELTA-RISK (ΔCDF)
(PRA QUANTIFICATION OF INTERNAL AND EXTERNAL EVENTS WITH COMPENSATORY MEASURES 3-6)

Basic Event	Probability	F-V	RAW	Description	Postulated Approach to Minimize Configuration Risk
SAC-MDP-TM-SSWB	2.30E-05	2.05E-04	9.92	SAC A IN MAINT. COINCIDENT WITH SSW B	Tier 3 Program[1].
SWS-MDP-TM-502AC	2.95E-04	2.53E-03	9.59	SWS PUMP TRAINS 502A AND 502C IN TEST AND MAINT	Tier 3 Program[1].
SAC-MDP-TM-RHRB	2.30E-05	1.83E-04	8.94	RHR B AND SAC A IN MAINT. DUE TO EMERGENT WORK	Tier 3 Program[1].
ACP-INV-FR-AD481	1.27E-04	9.63E-04	8.6	INVERTER FOR 1AD481 FAILS TO RUN	Compensatory measures already address the need to minimize testing and electrical maintenance with EDG OOS[3].
DCP-EDG-PORTGEN	2.50E-02	1.77E-01	7.92	PORTABLE GENERATOR FAILS	An additional compensatory measure could be considered to reduction in this failure probability due to testing pre-staging, or training would result in reductions in ICCDP and ICLERP.
SAC-MDP-TM-210AC	2.30E-05	1.43E-04	7.24	SAC PUMP TRAINS 210A AND 210C IN TEST AND MAINT	Tier 3 Program[1].
DCP-BKR-CO-41023	2.40E-05	1.14E-04	5.75	BREAKER 72-41023 TRANSFERS OPEN	Compensatory measures already address the needs to minimize testing and electrical maintenance with EDG OOS[3].
DGS-DGN-FS-AG400	1.31E-02	5.93E-02	5.47	DIVISION A DIESEL 1AG400 FAILS TO START	Do not remove Div A EDG from service. This would be a new compensatory measure or a stricter interpretation of the existing EDG C and D compensatory measure.

Notes to Table D-1:

Footnotes for Compensatory Measures for use During Extended EDG Outages

(1) Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM).

(2) In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.

(3) When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the associated mechanical division (A&C or B&D) must be capable, operable and available to mitigate the consequence of a LOOP condition.

(4) The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.

(5) Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.

(6) Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

Appendix E

FULL POWER INTERNAL EVENTS PROBABILISTIC RISK SUMMARY

Appendix E

FULL POWER INTERNAL EVENTS PROBABILSITIC RISK SUMMARY

E.1 QUANTITATIVE SUMMARY

The Hope Creek PRA is a systematic evaluation of plant risk utilizing the latest technology available for Probabilistic Risk Assessment (PRA). The Hope Creek PRA is classified as a full power internal events PRA meaning that severe accident sequences have been developed from internally initiated events, including internal floods.

A figure of merit commonly quoted in PRAs is core damage frequency (CDF). While this figure of merit does not entirely represent the value of the PRA, it is a widely used indicator. The core damage frequency (CDF) calculated in the Hope Creek 2008 PRA (HC108B) is 5.11E-6 per year. Refer to Section 3.6.4 for a discussion of the key contributors to the change in CDF.

The resulting CDF figure of merit is below the NRC's surrogate safety goal which indicates that Hope Creek poses no undue risk and is within the range of CDFs for other nuclear plants.

In addition to the evaluation of accident sequences that could lead to core damage, the Hope Creek PRA also includes the second risk metric specified in RG 1.174, an evaluation of the containment performance by examining the Large Early Release Frequency (LERF) associated with possible radionuclide releases.[1] The large early release frequency (LERF) calculated in the Hope Creek HC108B PRA is 4.76E-07 per year. The internal flood updated evaluation resulted in additional sequences that lead directly to LERF compared with previous PRA models.

(1) The Hope Creek Level 2 model quantifies release frequencies for the LERF end state. Refer to the Hope Creek Level 2 document (HC-PSA-015) for additional discussion.

The containment evaluation results also indicate that the Hope Creek Mark I containment evaluation is within the NRC surrogate safety goal.

The NRC in their Severe Accident Policy Statement (1985) stated that:

> *On the bases of current available information, the Commission concludes that existing plants pose no undue risk to the public health and safety and sees no present basis for immediate action on generic rule-making or other regulatory changes for these plants because of severe accident risk.*

The Hope Creek PRA has determined that there are no plant specific or unique features of Hope Creek that would alter this generic conclusion.

In addition, PSEG realizes that the numerical results summarized above are by no means the sole purpose of the PRA. Equally important are the assessment process, the knowledge gained by PSEG personnel, and the applications, current and future, that apply the PRA process to risk-informed decision making.

E.2 2008 PRA CDF UPDATE

This subsection summarizes the following:

- Overall risk metric results
- Initiating event impacts
- Functional accident class summary
- Comparison of the 2005C and 2008 model results

E.2.1 Overall Risk Metric Results

The CDF and LERF results based on the 2008 PRA Update (HC108B) are shown in Tables E.2-1 and E.2-2, respectively.

Tables E.2-1a and E.2-2a provide the results of the truncation sensitivity.

Table E.2-3 provides the HC108B CDF, LERF, and Conditional Large Early Release Probability (CLERP).

The HC108B CDF and LERF are calculated with the single top CAFTA model (developed with the ONE4ALL code) at a truncation of 1E-12/yr. The single top model accounts for both the accident sequence failure logic as well as the success logic.

- The Level 1 CDF is 5.11E-06/yr at a truncation of 1E-12/yr.
- The HC108B Level 2 LERF risk metric is calculated as 4.76E-07/yr also at a truncation of 1E-12/yr.

E.2.2 Initiating Event Contribution to CDF

Table E.2-4 summarizes the CDF contributors by initiating event. Figure E.2-1 displays the results of Table E.2-4 in graphical form, i.e., the CDF contributors by initiating event.

The initiating events with the highest risk contribution to the CDF risk metric are as follows:

- Loss of Offsite AC Power (%IE-TE)
- Loss of Service Water (%IE-SWS)
- Manual Shutdown (%IE-MS)
- Turbine Trip (%IE-TT)

E.2.3 Functional Accident Sequence Class Contribution to CDF

Table E.2-5 gives the definitions of the Hope Creek functional accident sequences.[1] These are consistent with the NEI guidance in NUMARC 91-04. Table E.2-5 also includes the PRA quantification of the functional classes for model HC108B.[1] Figure E.2-2 displays the results of Table E.2-5 in graphical form.

(1) The functional accident sequences are calculated using PRAQUANT. This division of sequences leads to some double counting (non-minimal cutsets).

The dominant Accident Class contributors to the CDF risk metric are as follows:

- Class IA: Loss of RPV Makeup at High RPV Pressure
- Class ID: Loss of RPV Makeup at Low RPV Pressure
- Class IIA: Loss of Decay Heat Removal (DHR)
- Class IBL: Late Station Blackout (SBO)

The overall CDF and the distribution of the CDF among the contributing functional accident sequence classes are consistent with the significant plant mitigating system capability at Hope Creek.

Top cutsets and individual accident sequences are discussed in Section E.3.

E.2.4 Overview of Model Changes

The advent of risk-informed regulation has necessitated that the PRA be current with the as-built, as-operated plant and be flexible enough to support the many varied applications anticipated.

The 2008 PRA update (HC108B) has resulted from changes to the Hope Creek PRA to ensure the fidelity of the as-built, as-operated plant, including the following:

- Revised success criteria with reference to completely new MAAP calculations
- Completely new Initiating Event Analysis (including additional initiating event types)
- Completely new Event Trees
- Completely new HRA
- Completely new data analysis
- Completely new Internal Flood Analysis
- Development of a sequence based model for Level 2

- Complete Level 2 update
- Incorporation of recent Hope Creek and industry initiating event frequency and component failure data

The 2008 model includes the disposition of a over 120 Level 1 PRA open items that were identified by previous PRA Peer Reviews or the "gap" analysis relative to the ASME PRA Standard. This includes the cumulative disposition of these gaps in models HC108A and HC108B.

E.2.5 <u>Conclusion</u>

This HC108B Quantification Notebook provides the PRA base model for the development of the on-line risk monitoring program, Maintenance Rule program, and other risk applications performed for the Hope Creek Generating Station.

The HC108B Hope Creek PRA LERF model is evaluated in HC PSA-015 (Level 2 Analysis/LERF) and summarized in the Quantification Notebook. The HC108B Hope Creek PRA Level 1 (CDF) model presented in this document serves as one of the main inputs to the Level 2 (LERF) analysis.

The changes made for the 2008 update is an accumulation of changes made in the HC108A and HC108B models are summarized for both HC108A and HC108B and are listed separately.

E.2.5.1 HC108A PRA Model Changes

<u>Plant Changes</u>

The HCGS plant has undergone extensive changes as a result of the EPU implementation. Among the significant plant changes are the following:

- Turbine replacement
- Digital FW control system

- Digital EHC control system
- Socket weld reassessment and reweld for DW main steam
- Addition of protective 500kV breaker is the switchyard
- Main Transformer A, B, C phases
- Cooling tower flow distribution piping modification

Other changes include the following:

- Implementation of OPRM to monitor core power flow oscillations and to automatically scram the unit given predetermined oscillation conditions.
- Extensive SSW changes
  - SSW Strainer Modifications
  - Valve replacements
  - Trash Racks (A, B, C, D)
  - Lube oil configuration
- Addition of time delay relays to avoid spurious failure:
  - RHR minimum flow valves
  - FW lube oil low pressure trip time delay
  - RCIC
  - HPCI
- Battery cell replacement
- MSSV Motor Operators
- SRV Pilot Disk Upgrade to Stellite 2'
- Hydrogen Water Chemistry
- Noble Metals Addition
- Back Pressure Trip on RCIC Turbine raised to 50 psig

Model Update

In addition to the plant changes identified above, model changes incorporated in the HC108A update include the following:

- Updated plant specific data and transient initiating event frequency
- Revised accident sequence event tree models

- Revised fault tree structures to address various issues
- Updated common cause failure probabilities
- Full Level 2 update
- Incorporation of resolutions to "gaps" identified to Capability Category II of the ASME PRA Standard
- Modified SW injection to RPV for Level 1 because it is not proceduralized.
- Added credit for use of CS from CST
- Added control of vent due to procedure change
- Removed credit for Condensate Transfer as RPV Injection source (inadequate calculational support)
- Seasonal success criteria for the SSW and SACS heat removal system
- Updated HRA using the EPRI HRA Calculator supported by new interviews and simulator observations
- Revised accident sequence definitions (Event Trees)
- Updated MAAP calculations to support the success criteria and accident sequence timing at the Extended Power Uprate (EPU) configuration
- Updated common cause failures incorporating the latest NRC data
- An update to the internal flood accident sequences evaluation to meet the ASME PRA Standard

E.2.5.2 HC108B Model Changes

As a result of the 2008 PRA Peer Review of HC108A and the roll-out process, several refinements were identified, including a procedural change.

<u>Procedure Change</u>

A change to the as-operated plant involved the Operations Department implementing changes to procedure AB.COOL-0002 to clarify crew actions to be taken if a single SSW pump was available to provide cooling in a loop with only one SACS pump operating, i.e., open both heat exchanger discharge valves on SSW.

Model Changes Identified as Part of PRA Peer Review Process:

The following model changes were identified and were resolved as part of the HC108B model development:

- Inverter room cooling logic
- Manual shutdown effects on SRV challenges
- FPS model change to include pumper truck
- Data used for Loss of DC Bus Criticality Factor
- HEP for Crosstie of EDGs (NR-XTIE-EDG)
- Internal Flood (SW pipe rupture frequency and TB flood frequency)
- Minor changes in BE database
- Revise SACS Dual Train Unavailability (SSW & SACS unavailable)
- Containment Isolation Treatment (include IA for Torus V.B.)
- SI Node (Add DW spray FT and remove AND gate for HEPs)
- Containment Isolation FT
- Modify IS node FT to include MS line isolation
- Modify FTS and FTR for SACS
- Revise the EDG Run failure probability
- HPCI and RCIC TDP failure probability

Based on both of the PRA models (HC108A and HC108B), no vulnerabilities have been uncovered; however, the revisions have allowed the use of the PRA to provide a better prioritization of systems, structures, and components for applications by incorporating into the model plant specific data, the latest procedures, and the current plant hardware modifications. These applications could include the following:

- Prioritization of testing of MOVs for GL 89-10
- Risk significance for the Maintenance Rule
- On-line maintenance risk assessment
- Severe Accident Mitigation Alternatives (SAMA) in support of Life Extension
- Extended Power Uprate (EPU)

- Containment Integrated Leak Rate Test (ILRT) interval extension
- MSPI
- RI-ISI
- Other risk ranking processes (e.g., CDBI)
- EDG AOT Extension Request

Table E.2-1

BASE CDF RESULTS

Station	HC108B
Hope Creek	5.11E-06/yr[1]

[1] Truncation of 1E-12/yr

Table E.2-1a

HOPE CREEK 2008 PRA (HC108B) LEVEL 1
TRUNCATION LIMIT SENSITIVITY EVALUATION

Truncation	# Cutsets	CDF	% of Base	Time
1.00E-08	62	2.05E-06	40.0%	4.0 secs.
1.00E-09	555	3.30E-06	64.5%	11.0 secs.
1.00E-10	3547	4.23E-06	82.7%	39.0 secs.
5.00E-11	6342	4.44E-06	86.9%	58.0 secs.
1.00E-11	20643	4.79E-06	93.7%	2.7 mins.
5.00E-12	34446	4.91E-06	96.1%	4.2 mins.
1.00E-12[1]	117006	5.11E-06	100.0%	12.3 mins.
5.00E-13	200441	5.18E-06	101.3%	20.0 mins.
2.00E-13	401122	5.25E-06	102.6%	39.1 mins.
1.00E-13	692955	5.29E-06	103.5%	1.2 hours

[1] The change in CDF for the next decade drop in truncation beyond 1E-12/yr is 3.5%. This is within the example criteria shown in the ASME PRA Supporting Requirements for QU-B3.

Table E.2-2

BASE LERF RESULTS

Station	HC108B
Hope Creek	4.76E-07/yr

Table E.2-2a

HOPE CREEK 2008 PRA LEVEL 2

TRUNCATION LIMIT SENSITIVITY EVALUATION

Truncation	# Cutsets	LERF	% of Base	Time
1.00E-08	2	1.21E-07	25.5%	4.0 secs.
1.00E-09	50	2.30E-07	48.4%	11.0 secs.
1.00E-10	444	3.55E-07	74.7%	39.0 secs.
5.00E-11	840	3.85E-07	80.9%	1.0 mins.
1.00E-11	2987	4.32E-07	90.7%	2.8 mins.
5.00E-12	5304	4.48E-07	94.2%	4.4 mins.
1.00E-12(1)	17880	4.76E-07	100.0%	12.8 mins.
5.00E-13	29840	4.84E-07	101.8%	19.9 mins.
2.00E-13	58583	4.94E-07	103.8%	31.9 mins.
1.00E-13	97493	5.00E-07	105.1%	49.1 mins.

(1) The change in LERF for the next decade drop in truncation beyond 1E-12/yr is 5.1%. This is consistent with the example criteria shown in the ASME PRA Supporting Requirements for QU.

Table E.2-3

2008 PRA BASE CDF VS. LERF RESULTS

Station	CDF (HC108B)	LERF (HC108B)	CLERP (LERF/CDF)
Hope Creek	5.11E-06/yr	4.76E-07/yr	9.3%

Table E.2-4

HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-TE	LOSS OF OFFSITE POWER INITIATING EVENT	2.37E-02	1.82E-01	9.31E-07	3.93E-05
%IE-SWS	LOSS OF SERVICE WATER INITIATING EVENT	1.79E-04	1.59E-01	8.13E-07	4.54E-03
%IE-MS	MANUAL SHUTDOWN INITIATING EVENT	1.46E+00	1.50E-01	7.67E-07	5.25E-07
%IE-TT	TURBINE TRIP WITH BYPASS	7.03E-01	1.22E-01	6.24E-07	8.87E-07
%IE-S2-WA	SMALL LOCA - WATER (BELOW TAF)	6.20E-04	5.40E-02	2.76E-07	4.45E-04
%IE-S2-ST	SMALL LOCA - STEAM (ABOVE TAF)	6.20E-04	4.45E-02	2.28E-07	3.67E-04
%IE-TC	LOSS OF CONDENSER VACUUM	9.33E-02	3.98E-02	2.03E-07	2.18E-06
%FLFPS-CR	FPS RUPTURE OUTSIDE CONTROL ROOM	1.10E-05	3.62E-02	1.85E-07	1.68E-02
%IE-ISLOCAD	ISLOCA INITIATOR FOR ECCS DISCHARGE PATHS	1.63E-05	2.22E-02	1.14E-07	6.96E-03
%IE-TM	MSIV CLOSURE	5.62E-02	2.16E-02	1.10E-07	1.97E-06
%FL-FPS-5302	INT. FLOOD OUTSIDE LOWER RELAY ROOM	6.62E-06	1.90E-02	9.71E-08	1.47E-02
%IE-TF	LOSS OF FEEDWATER	4.49E-02	1.72E-02	8.79E-08	1.96E-06
%IE-SACS	LOSS OF SACS INITIATING EVENT	1.16E-04	1.54E-02	7.87E-08	6.79E-04
%FLSWAB-RACS-U	FREQ OF COMMON HEADER TO RACS RUPTURE (UNISOLABLE)	7.60E-08	1.49E-02	7.62E-08	1.00E+00
%FLSWA-RACS-U	FREQ. OF UNISOLABLE SW A PIPE RUPT IN RACS ROOM	5.70E-08	1.11E-02	5.68E-08	9.96E-01
%FLSWB-RACS-U	FREQ. OF UNISOLABLE SW B PIPE RUPT. IN RACS ROOM	5.70E-08	1.11E-02	5.68E-08	9.96E-01
%IE-ACD	LOSS OF AC BUS D INITIATING EVENT	2.07E-03	7.78E-03	3.98E-08	1.92E-05
%IE-SORV2	2 or More SORVs	2.44E-04	6.19E-03	3.16E-08	1.30E-04
%FLFPS-RBU	FPS RUPTURE IN RB UPPER LEVELS	6.60E-05	5.60E-03	2.86E-08	4.34E-04
%FLSWA-RACS-I	FREQ. OF ISOLABLE SW A PIPE RUPTURE IN RACS ROOM	1.43E-06	5.14E-03	2.63E-08	1.84E-02
%FLSWB-RACS-I	FRQ. OF ISOLABLE SW B PIPE RUPTURE IN RACS ROOM	1.43E-06	4.87E-03	2.49E-08	1.74E-02
%IE-TI	INADVERTENTLY OPEN SRV INITIATING EVENT	1.44E-02	4.82E-03	2.46E-08	1.71E-06
%IE-IAS	LOSS OF INSTRUMENT AIR INITIATOR	6.17E-03	4.50E-03	2.30E-08	3.73E-06
%IE-MLRHR	Medium LOCA – RHR	1.44E-05	4.08E-03	2.09E-08	1.45E-03
%IE-MLRECIRC	Medium LOCA – Reactor Recirculation	1.18E-05	3.34E-03	1.71E-08	1.45E-03
%FLTORUS	TORUS RUPTURE IN TORUS ROOM	2.80E-06	3.32E-03	1.70E-08	6.06E-03

Table E.2-4

HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-ACA	LOSS OF AC BUS A INITIATING EVENT	2.89E-04	2.96E-03	1.51E-08	5.24E-05
%FL-FPS-5537	FPS RUPTURE OUTSIDE 125V DC ROOMS	1.34E-05	2.62E-03	1.34E-08	1.00E-03
%IE-MLRWCU	Medium LOCA – RWCU	8.63E-06	2.44E-03	1.25E-08	1.45E-03
%IE-TE-REC	LOSS OF OFFSITE POWER INITIATING EVENT (RECOVERED LOOP EVENT)	2.37E-02	2.28E-03	1.17E-08	4.92E-07
%IE-MLFW	Medium LOCA – Feedwater	7.22E-06	2.04E-03	1.04E-08	1.44E-03
%FLFPS-CD	FPS RUPTURE IN CONTROL DIESEL BUILDING	8.20E-05	1.79E-03	9.15E-09	1.12E-04
%IE-MLNBINST	Medium LOCA – Nuclear Boiler Instrumentation	5.24E-06	1.48E-03	7.57E-09	1.44E-03
%FLTORUSRB	TORUS SUCTION LINE RUPTURE IN ECCS ROOM	2.70E-06	1.28E-03	6.54E-09	2.42E-03
%IE-ACB	LOSS OF AC BUS B INITIATING EVENT	2.89E-04	1.22E-03	6.24E-09	2.16E-05
%FLSW-SACS-A	SW RUPTURE IN SACS A ROOM	4.80E-07	1.06E-03	5.42E-09	1.13E-02
%FLSACS-A	SACS A RUPTURE	2.70E-04	7.97E-04	4.07E-09	1.51E-05
%IE-ISLOCAS	ISLOCA INITIATOR FOR SDC SUCTION PATH	5.01E-07	7.58E-04	3.88E-09	7.74E-03
%FLSW-SACS-B	SW RUPTURE IN SACS B ROOM	4.80E-07	7.03E-04	3.59E-09	7.49E-03
%IE-LLRHR	Large LOCA – RHR	9.69E-06	6.26E-04	3.20E-09	3.30E-04
%IE-MLHPCI	Medium LOCA – HPCI	1.80E-06	5.92E-04	3.03E-09	1.68E-03
%FLSACS-B	SACS B RUPTURE	2.70E-04	5.66E-04	2.89E-09	1.07E-05
%IE-ACC	LOSS OF AC BUS C INITIATING EVENT	2.89E-04	5.60E-04	2.86E-09	9.91E-06
%IE-LLRECIRC	Large LOCA – Reactor Recirculation	8.74E-06	5.50E-04	2.81E-09	3.22E-04
%FLTB-CW	TURBINE BUILDING FLOOD	1.50E-03	5.27E-04	2.69E-09	1.80E-06
%IE-BOCMSA	Main Steam Line A Break outside Containment	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSB	Main Steam Line B Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSC	Main Steam Line C Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-BOCMSD	Main Steam Line D Break outside	9.66E-09	4.92E-04	2.52E-09	2.60E-01
%IE-MLMS	Medium LOCA – Main Steam	1.54E-05	3.78E-04	1.93E-09	1.25E-04
%FLSWAB-RACS-I	FREQ. OF ISOLABLE SW A & B PIPE RUTPURE IN RACS ROOM (TO RACS HX)	5.70E-07	3.37E-04	1.72E-09	3.02E-03

Table E.2-4

HCGS HC108B LEVEL 1 CDF CONTRIBUTION BY INITIATING EVENT
(CDF = 5.11E-6/YR AT 1E-12/YR TRUNCATION)

BASIC EVENT ID	DESCRIPTION	Frequency (/yr)	F-V	CDF (/yr)	CCDP
%IE-LLMS	Large LOCA – Main Steam	1.00E-05	3.36E-04	1.72E-09	1.72E-04
%IE-MLCS	Medium LOCA – Core Spray	9.34E-06	3.15E-04	1.61E-09	1.72E-04
%IE-LLFW	Large LOCA – Feedwater	4.53E-06	2.85E-04	1.46E-09	3.22E-04
%IE-LLRWCU	Large LOCA – RWCU	4.53E-06	2.85E-04	1.46E-09	3.22E-04
%IE-LLADS	Large LOCA - Spurious ADS Actuation	8.48E-06	2.84E-04	1.45E-09	1.71E-04
%IE-BOCHPCI	HPCI Steam Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-BOCRCIC	RCIC Steam Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-BOCRWCU	RWCU Line Break outside Containment	5.11E-09	2.60E-04	1.33E-09	2.60E-01
%IE-LLCS	Large LOCA - Core Spray	5.40E-06	2.30E-04	1.18E-09	2.18E-04
%IE-DCAB	LOSS OF DCA & DCB	7.14E-07	1.44E-04	7.36E-10	1.03E-03
%IE-R	EXCESSIVE LOCA EVENT	6.38E-09	1.39E-04	7.11E-10	1.11E-01
%IE-BOCFWA	Feedwater Line A Break outside	2.23E-09	1.14E-04	5.83E-10	2.61E-01
%IE-BOCFWB	FEEDWATER LINE B BREAK OUTSIDE CONTAINMENT	2.23E-09	1.14E-04	5.83E-10	2.61E-01
%IE-MLRCIC	Medium LOCA – RCIC	3.27E-06	7.67E-05	3.92E-10	1.20E-04
%IE-LLHPCI	Large LOCA – HPCI	1.13E-06	3.63E-05	1.86E-10	1.64E-04
%IE-RACS	LOSS OF RACS	1.56E-05	5.86E-07	3.00E-12	1.92E-07

Table E.2-5

SUMMARY OF HC108B CDF BY ACCIDENT SEQUENCE SUBCLASS(1)

Accident Class	Definition	Result	% CDF
CLS-IA	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	1.37E-06	26.1%
CLS-IBE	Accident sequences involving a station blackout and loss of coolant inventory makeup. (Class IBE is defined as "Early" Station Blackout events with core damage at less than 4 hours.)	5.32E-08	1.0%
CLS-IBL	Class IBL is defined as "Late" Station Blackout events with core damage at greater than 4 hours.	5.45E-07	10.4%
CLS-IC	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	4.51E-08	0.9%
CLS-ID	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	1.29E-06	24.6%
CLS-IE	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	1.11E-07	2.1%
CLS-IIA	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	9.28E-07	17.7%
CLS-IIL	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	1.87E-09	0.0%
CLS-IIT	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced prior to containment failure.	1.87E-10	0.0%
CLS-IIV	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment vent.	5.41E-08	1.0%
CLS-IIIB	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	4.85E-07	9.2%
CLS-IIIC	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	2.40E-08	0.5%

Table E.2-5

SUMMARY OF HC108B CDF BY ACCIDENT SEQUENCE SUBCLASS[1]

Accident Class	Definition	Result	% CDF
CLS-IIID	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	5.89E-08	1.1%
CLS-IVA	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	1.55E-07	3.0%
CLS-IVL	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	2.97E-09	0.1%
CLS-V	Unisolated LOCA outside containment.	1.30E-07	2.5%
Total		5.25E-06[2]	100.0%

(1) Results based on truncation value of 1E-12/yr.

(2) Accident class total CDF of 5.25E-6/yr is slightly higher than the single top model CDF of 5.11E-6/yr due to the generation of non-minimal cutsets between accident classes.

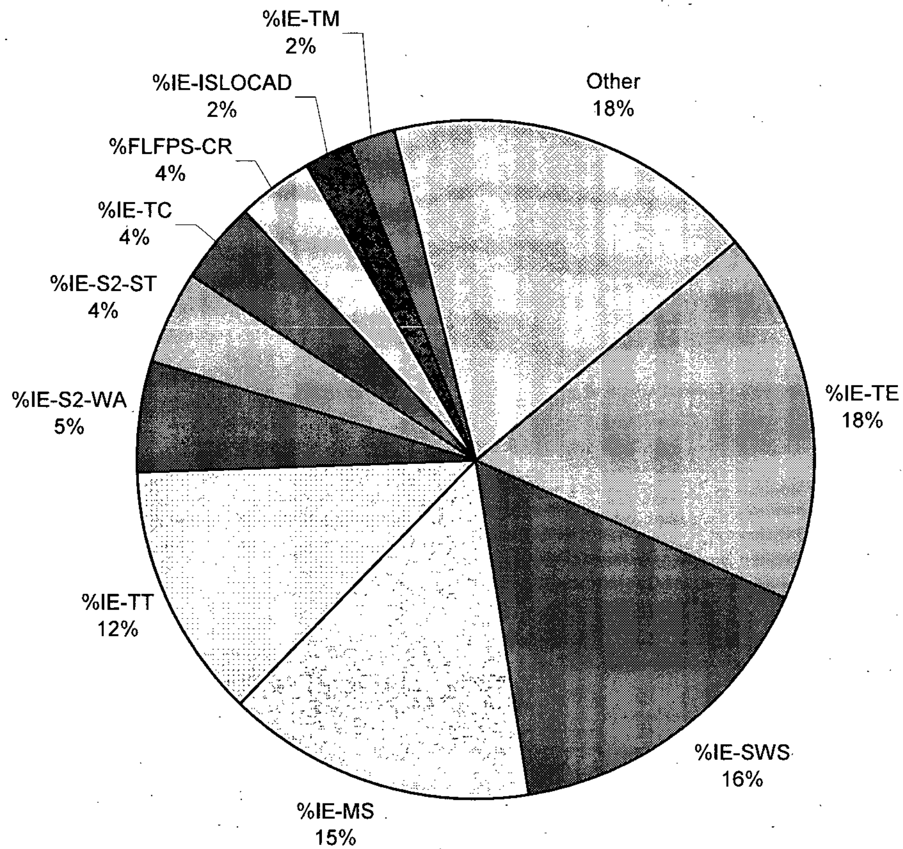


Figure E.2-1 HC108B CDF Contribution by Initiating Event

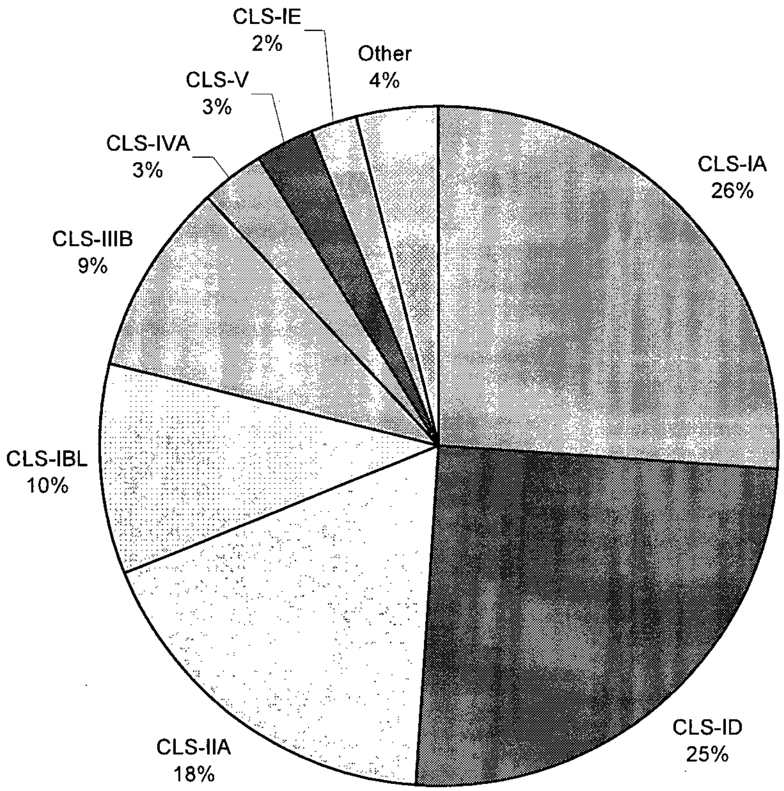


Figure E.2-2 HC108B CDF Contribution by Accident Class

Appendix F

CHARACTERIZING THE SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK

Appendix F

CHARACTERIZING THE SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK

F.1 PURPOSE: PROCESS TO IDENTIFY SOURCES OF MODEL UNCERTAINTIES AND RELATED ASSUMPTIONS

This appendix summarizes the process and the results of the identification of sources of model uncertainty and related assumptions. This process is developed based upon NUREG-1855 [F-1] and the complimentary EPRI guidance [F-5].

F.2 BACKGROUND

The Hope Creek Full Power Internal Events (FPIE) PRA (HC108B) is developed consistent with the ASME PRA Standard (2005) [F-4] as endorsed by R.G. 1.200 Rev. 1 (2007) [F-3]. This has been demonstrated by a self-assessment of the Hope Creek Model [HC108B] and its documentation.

After the freeze date of the HC108B model input, the NRC issued NUREG-1855 to provide guidance regarding the treatment of uncertainties within the PRA and more specifically for PRA applications. In addition, a combined ASME/ANS PRA Standard [F-2] was issued after the freeze date for the HC108B input. This revised standard incorporates much of the ASME PRA Standard (2005) [F-4] as endorsed by R.G. 1.200 [F-3] except it also incorporates some small changes to Supporting Requirements plus the revision to the uncertainty Supporting Requirements. The ASME/ANS Combined PRA Standard defines "what" needs to be done regarding modeling uncertainties. The NRC guidance in NUREG-1855 [F-1] as supported by EPRI guidance [F-5] provides "how" this requirement can be implemented. As a result, the Risk Management Team has reviewed NUREG-1855 [F-1] and the companion EPRI document [F-5] to develop the approach to the treatment of modeling uncertainty for Hope Creek.

Specifically, the new combined ASME/ANS PRA Standard describes the required treatment of modeling uncertainties and related assumptions for the base model as follows:

> For each PRA element (e.g., IE, AS, SY...):
>
> > DOCUMENT the sources of model uncertainty and related assumptions (as identified in QU-E1 and QU-E2) associated with the ...(element)
>
> For QU-E1:
>
> > IDENTIFY sources of model uncertainty
>
> For QU-E2:
>
> > IDENTIFY assumptions made in the development of the PRA model
>
> For QU-E4:
>
> > For each source of model uncertainty and related assumption identified in QU-E1 and QU-E2, respectively, IDENTIFY how the PRA model is affected (e.g., introduction of a new basic event, changes to basic event probabilities, change in success criterion, introduction of a new initiating event) [Note (1)].

Specifically, these revised requirements have eliminated the need to "EVALUATE the sensitivity of the results" for the <u>base PRA model</u> that existed in the ASME PRA Standard (2005) [F-4] as noted below:

> EVALUATE the sensitivity of the results to key model uncertainties and key assumptions using sensitivity analyses [Note (1)].

With the issuance of the combined ASME/ANS PRA Standard, the EVALUATION is deferred to the implementation of a PRA application. In the context of an application, the sensitivity evaluation would be required. Appendix B summarizes the sensitivity evaluations for the EDG AOT application.

F.3 OVERVIEW: IDENTIFICATION

This appendix characterizes the Hope Creek FPIE PRA model uncertainty consistent with the NRC guidance in NUREG-1855 [F-1] to satisfy the ASME/ANS PRA Standard [F-2] as endorsed by R.G. 1.200 Rev. 2 [F-13]. According to NUREG-1855 and the NRC workshop on modeling uncertainty held in May 2009, the characterization of modeling uncertainties into the base PRA model documentation is sufficient to meet the ASME/ANS PRA Standard Supporting Requirements (SRs) defined by the combined ASME/ANS PRA Standard(1) [F-2]. The following SRs describe these requirements:

- QU-E1: IDENTIFY sources of model uncertainty.
- QU-E2: IDENTIFY assumptions made in the development of the PRA model.
- QU-E4: For each source of model uncertainty and related assumption identified in QU-E1 and QU-E2, respectively, IDENTIFY how the PRA model is affected (e.g., introduction of a new basic event, changes to basic event probabilities, change in success criterion, introduction of a new initiating event)
- QU-F4: DOCUMENT the characterization of the sources of model uncertainty and related assumptions (as identified in QU-E4).
- LE-F3: IDENTIFY and CHARACTERIZE the LERF sources of model uncertainty and related assumptions, consistent with the requirements of Tables 2.2.7-2(d) and 2.2.7-2(e).
- IE-D3, AS-C3, SC-C3, SY-C3, HR-I3, DA-E3, LE-G4, IFPP-B3, IFSO-B3, IFSN-B3, IFEV-B3, and IFQU-B3: DOCUMENT the sources of model uncertainty and related assumptions (as identified in QU-E1 and QU-E2 [or LE-F3]) associated with ...[each element].

EPRI, in cooperation with the NRC, has performed a comprehensive evaluation of FPIE PRAs to identify sources of modeling uncertainty. The resulting proposed generic list of modeling uncertainties is provided by EPRI [F-5].

(1) It is noted that the Hope Creek PRA has been developed consistent with the ASME PRA Standard (2005) [F-4] as endorsed by R.G. 1.200 Rev. 1 (2007) [F-3]. The exception is that several uncertainty related SRs were modified in the Combined Standard. For these modified SRs, the combined ASME/ANS standard [F-2] is used by Hope Creek.

The combined NRC-EPRI list of generic sources of model uncertainty are as follows:

1. Grid Stability (includes LOOP initiating event and offsite AC recovery)
2. Support System Initiating Events
3. LOCA initiating event frequencies
4. Operation of equipment after battery depletion
5. RCP seal LOCA treatment – PWRs
6. Recirculation pump seal leakage treatment – BWRs with Isolation Condensers
7. Impact of containment venting on core cooling system NPSH
8. Core cooling success following containment failure or venting through non hard pipe vent paths
9. Room heatup calculations
10. Battery life calculations
11. Number of PORVs required for bleed and feed – PWRs
12. Containment sump / strainer performance
13. Impact of failure of pressure relief
14. Operability of equipment in beyond design basis environments
15. Credit for ERO
16. Piping failure mode
17. Core melt arrest in-vessel
18. Thermally induced failure of hot leg/SG tubes – PWRs
19. Vessel failure mode
20. Ex-vessel cooling of lower head
21. Core debris contact with containment
22. ISLOCA IE Frequency determination
23. Treatment of Hydrogen combustion in BWR Mark III and PWR ice condenser plants

In addition to these generic sources of model uncertainty, the NRC and EPRI identified three additional sources of model uncertainty that were not identified from a phenomenological or interpreted behavior perspective. Rather, these three issues were identified as potential sources of model uncertainty because they are areas of uncertainty that can be significant contributors to CDF and LERF and involve potentially different modeling approaches.

24. Basis for Human Error Probabilities (HEPs)
25. Treatment of Human Failure Events (HFE) dependencies
26. Intra-system common cause events

These are discussed in Appendix F.6.

Finally, NRC and EPRI identified other potential sources of model uncertainty that may have impacts on specific applications of the model but will typically not be significant contributors to the base model assessment. As such, plant-specific identification and characterization of these issues as specific sources of model uncertainty would not be required to meet Capability Category II of the ASME/ANS PRA Standard. These include the following:

1. Treatment of boron dilution events.
2. Selection of prior distributions when carrying out a Bayesian analysis of data.
3. Treatment of rare and extremely rare events.
4. Moderator temperature coefficient – important in PWR ATWS.
5. Pressurized Thermal Shock – PWRs.
6. Credit for non-standard success paths (e.g., use of alternate injection systems).
7. CDF and LERF definitions – the PRA standard allows some flexibility in defining these parameters.
8. Large LOCA long term oxidation in BWRs – since BWRs are designed to maintain 2/3 core height for a very large break LOCA, injection by one LPCI pump into the shroud area may maintain the covered core suF-cooled. Cooling of the top 1/3 core for a substantial time is questionable since long term steam cooling effect may not be ensured.
9. Engineering analyses – separate engineering analyses may use codes or invoke other assumptions that may introduce potential sources of modeling uncertainty.

10. Level control during ATWS in BWRs – difficult to perform, but more importantly, the power level achieved in different situations is uncertain. Power/flow oscillations can occur and its impact on the core is uncertain.
11. Post-LOCA boron precipitation in PWRs - modeled in design basis event thermal hydraulic evaluations, but is not always modeled in PRAs.
12. Digital instrumentation and control.
13. Credit for non-safety related equipment in recovery actions.
14. Passive system degradation mechanisms – aging of active components is incorporated into the periodic data analysis updates but passive system reliability is generally not accounted for.
15. Water hammer impacts on system performance.
16. Selection of components in a common cause group.
17. Capability of battery charger to start and carry loads if the battery is unavailable.
18. Standby failure rate model.

In addition to the assessment for the generic list of candidate model uncertainties, an assessment of plant-specific features and modeling approaches is performed to determine if additional sources of model uncertainty and related assumptions should be incorporated into the list. This Hope Creek assessment is summarized in Section F.5.

The discussion of the standard sensitivity cases recommended in Section 3 and Appendix A of the EPRI report [F-5] for HEPs and CCF values is provided in Section F.6. These issues were identified as generic high level sources of modeling uncertainty rather than trying to identify all potential sources of model uncertainty associated with these issues because they are generally understood and accepted as areas of uncertainty associated with the methodologies that can be significant contributors to CDF and LERF.

Finally, Section F.6 summarizes the conclusions from the implementation of the NUREG-1855 uncertainty treatment evaluation process for characterizing the sources of model uncertainty for Hope Creek.

F.4 GENERIC SOURCES OF MODEL UNCERTAINTY

In this appendix, for each applicable generic model uncertainty item that was shown in Appendix A of the EPRI report [F-5] (i.e., in Table F-1), a plant-specific issue characterization and assessment is provided to fully satisfy the related supporting requirements of the Combined ASME/ANS PRA Standard [F-2].

Table F-1 in this appendix implements this process for Hope Creek where the specific supporting requirements that are being treated are clearly identified. This includes the supporting requirements listed above as well as those supporting requirements for documenting the sources of model uncertainty and related assumptions associated with each PRA element (IE-D3, AS-C3, SC-C3, SY-C3, HR-I3, DA-E3, LE-G4, IFPP-B3, IFSO-B3, IFSN-B3, IFEV-B3, and IFQU-B3).

The results of this assessment documented in Table F-1 and NUREG-1855 for the generic sources of modeling uncertainty considerations for Hope Creek lead to the following list of candidate sources of modeling uncertainty to be considered in the EDG AOT extension application:

- Grid stability (LOOP frequency)
- HEPs and Dependent HEPs
- Common Cause modeling

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
Initiating Event Analysis (to support meeting IE-D3 which replaced IE-D3 from the ASME PRA Standard)						
1. Grid stability	Recently the stability of at least some local areas of the electric power grid has been questioned. The potential duration and complexities of recovery from such events are hard to dismiss. Three different aspects relate to this issue: 1a. LOOP Initiating Event Frequency 1F. Conditional LOOP Frequency 1c. Availability of DC power to perform restoration actions	LOOP sequences including consequential LOOP sequences	NUREG/CR-6890 [F-6] is used to develop the prior distribution for the LOOP initiator frequency and incorporates four causal categories (Plant centered, Switchyard centered, Grid related, and Weather related). The priors utilize industry data for the plant centered, switchyard centered, and weather LOOP categories; however, region specific grid related LOOP data that is utilized for the prior. A Bayesian update for each category with plant specific data from 2005-2008 is utilized to obtain a total plant specific LOOP and DLOOP frequency.	1) The generic industry data for the four LOOP categories is applicable to the site and appropriate to use as a prior distribution for the plant-specific LOOP frequency development and four years worth of additional plant-specific experience is sufficient to perform the Bayesian update process.	1) The LOOP initiator frequency is apportioned into the four causal factors in the model with a percentage assigned to each category.	The overall approach for the LOOP frequency and fail to recover probabilities utilized is considered an industry good practice, but is not yet considered a consensus model approach. This includes issues with grid stability. It is retained as a candidate modeling uncertainty.
			The industry wide data in NUREG/CR-6890 [F-6] for the failure to recovery probabilities for the four LOOP categories are utilized directly for the applicable time frames in the model.	2) The industry wide recovery data is applicable to the site for the four causal factors included in the model.	2) LOOP recovery failures are included depending on the accident sequence progression.	

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
1. (cont'd)			The consequential LOOP failure probabilities are derived consistent with the NRC recommended generic values [F-8] of ~2E-3 and ~2E-2 given a reactor trip or LOCA, respectively.	3) The use of generic data for consequential LOOP events is assumed to be applicable for the site and the consequential LOOP events are assumed to be similar to other loss of grid events.	3) The loss of grid LOOP recovery failure data is utilized for the consequential LOOP event sequences.	Realistic. As such, this should not be a source of model uncertainty in most applications.
			Offsite power restoration is dictated by procedure. Restoration is possible via breaker control using DC power available via separate batteries in the switchyard.	4) When offsite power is available at the switchyard, then power is available to charge the batteries needed for breaker control to align power to the site. The specific failure modes of the offsite restoration are implicitly included via the use of the generic LOOP recovery probabilities.	4) No additional adjustments or system model changes are incorporated when using the different LOOP recovery probabilities. Available recovery times conservatively chosen to account for restoration time uncertainty.	Realistic with slight conservative bias on the recovery times utilized. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
2. Support System Initiating Events	Increasing use of plant-specific models for support system initiators (e.g., loss of SW, CCW, or IA, and loss of AC or DC buses) have led to inconsistencies in approaches across the industry. A number of challenges exist in modeling of support system initiating events: 2a. Treatment of common cause failures 2F. Potential for recovery	Support system event sequences	Support System Initiating Event fault trees are developed for loss of SW, loss of IA, loss of RACS, and loss of TACS.	1) The loss of support system success criteria are developed consistent with the post-trip configuration requirements and mission time requirements (i.e., 24 hour MTTR assumed consistent with the 24 hour mitigation mission time).	1) For the standby contributors in the support system initiating event, the same basic events are utilized in the SSIE fault tree and in the mitigation fault tree.	Realistic with slight conservative bias because MTTR is typically less than 24 hours. This should not be a source of model uncertainty in most applications.
			The CCF for the fail-to-run terms is based on annualized mission times using generic alpha factors, but with plant-specific information for the independent failure rate.	2) The use of the generic alpha factors based on industry wide experience is applicable for the site.	2) The fail-to-run CCF terms dominate the overall contribution to the SSIE frequency evaluation.	Slight conservative bias since Alpha factors are known to be high when utilized in an annualized fashion and compared to plant-specific experience. This should not be a source of model uncertainty in most applications.
			The support system initiating events are generally used as is with no additional credit for recovery. Restoration of support system to prevent a plant challenge (e.g., scram) is included in the model. This evaluation is judged to be slightly conservative and does not result in a significant modeling uncertainty.	3) The lack of credit for recovery from the support system initiating events will not significantly impact the CDF and LERF distribution.	3) No basic events included in model for recovery from the loss of support system initiators.	No recovery items are identified as a candidate source of model uncertainty. Therefore, this should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
3. LOCA initiating event frequencies	It is difficult to establish values for events that have never occurred or have rarely occurred with a high level of confidence. The choice of available data sets or use of specific methodologies in the determination of LOCA frequencies could impact base model results and some applications.	LOCA sequences	The pipe break portion of the LOCA initiating event frequencies are based on a pipe segment count and per segment failure probabilities from the EPRI methodology [F-9]. The component rupture portion of the LOCA initiating event frequencies are based on the component rupture data and methodology utilized in the NRC RMIEP study [F-10].	1) The use of generic data from the EPRI methodology and RMIEP study is generally applicable to the site.	1) In general, the LOCA frequencies are higher than those reported in more recent studies (e.g., NUREG-6928 [F-10]). Therefore, a slight conservative bias in the LOCA initiating event frequencies might be present.	The LOCA frequency values represent a slight conservative bias. This should not be a source of model uncertainty in most applications.
Accident Sequence Analysis (to support meeting AS-C3 which replaced AS-C3 from the ASME PRA Standard)						
4. Operation of equipment after battery depletion	Station Blackout events are important contributors to baseline CDF at nearly every US NPP. In many cases, battery depletion may be assumed to lead to loss of all system capability. Some PRAs have credited manual operation of systems that normally require dc for successful operation (e.g., turbine driven systems such as RCIC and AFW).	Credit for continued operation of these systems in sequences with batteries depleted (e.g., long term SBO sequences)	No credit is taken for continued operation of any systems without DC power that normally require DC power for operation. This includes HPCI, and the SRVs. The exceptions are: – The local IC operation after DC batteries deplete using existing procedures – Operation of 4kV breakers to restore offsite AC power using skill of craft	1) Operation of systems without DC that normally require DC for operation is not readily viable. Certain systems are well designed for which manual actions are acceptable without DC power.	1) Systems that normally require DC for operation are not credited for continued operation upon battery depletion in the event sequence modeling.	No credit for equipment operation after battery depletion may represent a slight conservative bias. This should not be a source of model uncertainty in most applications.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
5. RCP seal LOCA treatment – PWRs	The assumed timing and magnitude of RCP seal LOCAs given a loss of seal cooling can have a substantial influence on the risk profile.	Accident sequences involving loss of seal cooling	N/A	N/A	N/A	N/A
6. Recirculation pump seal leakage treatment – BWRs w/ Isolation Condensers	Recirculation pump seal leakage can lead to loss of the Isolation Condenser. While recirculation pump seal leakage is generally modeled, there is no consensus approach on the likelihood of such leaks.	Accident sequences with long-term use of isolation condenser and possible adverse impact on plants with low back pressure trip on RCIC.	Explicitly modeled in the PRA with discrete seal LOCA sizes during SBO events. A large seal LOCA initiated at t=0 of the SBO is considered to be slightly conservative.	Size of LOCA segmented probabilistically into two sizes. This breakdown adequately discretizes the spectrum of leaks.	RCIC back pressure trip due to the seal LOCA based on deterministic calculations.	No credit for the RCIC when the seal LOCA causes events that result in ED or trip RCIC. This treatment is judged to be slightly conservative because of the size and timing of the assumed large seal LOCA. A more realistic treatment would reduce the risk profile. Modeling uncertainty is not expected to challenge any acceptance guidelines for anticipated applications. This is not retained as a candidate modeling uncertainty.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
Success Criteria (to support meeting SC-C3 which replaced SC-C3 from the ASME PRA Standard)						
7. Impact of containment venting on core cooling system NPSH	Many BWR core cooling systems utilize the suppression pool as a water source. Venting of containment as a decay heat removal mechanism or containment failure can substantially reduce NPSH, even lead to flashing of the pool. This rapid drop in containment pressure may lead to local steaming that causes steam binding in pumps taking suction on the suppression pool. The treatment of such scenarios varies across BWR PRAs.	Loss of containment heat removal scenarios with containment venting successful or the induced containment failure.	No credit is taken for the use of injection systems with suction from the suppression pool following uncontrolled containment venting or the induced containment failure.	1) Upon successful initiation of uncontrolled containment venting or large containment failure, it is assumed that NPSH is lost for all systems taking suction from the suppression pool (i.e., HPCI and LP ECCS – CS and LPCI). Deterministic thermal hydraulic calculations are performed to support the controlled venting success criteria.	1) HPCI, RCIC, LPCI and Core Spray are not credited for success after uncontrolled containment venting or the induced containment failure.	No credit for these systems after uncontrolled containment venting or large containment failure represents a slight conservative bias based on thermal hydraulic analyses. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
8. Core cooling success following containment failure or venting through non-hard pipe vent paths	Loss of containment heat removal leading to long-term containment over-pressurization and failure can be a significant contributor in some PRAs. Consideration of the containment failure mode might result in additional mechanical failures of credited systems. Containment venting through "soft" ducts or containment failure can result in loss of core cooling due to environmental impacts on equipment in the reactor building, loss of NPSH on ECCS pumps, steam binding of ECCS pumps, or damage to injection piping or valves. The Hope Creek hard pipe vent options will make these effects probabilistically small. There is no definitive reference on the proper treatment of these issues.	Long term loss of decay heat removal scenarios, i.e., Class II sequences. Failure of the containment heat removal safety function causes failure of the RPV injection systems.	*With containment venting unsuccessful:* Limited credit is taken for continued injection after containment failure. FW and CRD are the only viable high pressure injection sources. At Hope Creek, FW is a motor driven system located in the Turbine Building.	1) Low pressure injection sources internal to containment (LPCI and Core Spray from the suppression pool) are probabilistically evaluated to be available before containment failure. Low pressure injection sources internal to containment are also assumed to fail after containment failure due to the items listed in the discussion of the issue.	1) LPCI and Core Spray are not credited for success after containment failure even if lined up to the CST prior to containment failure and adverse conditions exist in the Reactor Building.	No credit for these systems after containment failure may represent a slight conservative bias. This should not be a source of model uncertainty in most applications.
				2) HPCI and RCIC are assumed to be unavailable prior to containment failure since high pool temperatures would preclude their use from the suppression pool and the RPV would be depressurized using the SRVs per procedure rendering the CST suction source also ineffective.	2) HPCI and RCIC are not credited for success after containment failure.	No credit for HPCI and RCIC systems after containment failure may represent a slight conservative bias. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
8. (cont'd)				3) Other alternate low pressure injection systems are not credited for success during the time frame prior to containment failure because the SRVs cannot keep the RPV depressurized. In addition, if a large containment failure occurs, injection paths may be disrupted leading to loss of these external sources. This failure probability is based on a detailed structural analysis of the Mark I containment design and large scale ultimate failure testing of steel containments.	3) Other alternate low pressure injection systems (e.g., Fire Water and SSW) are not credited for success both before and after containment failure unless aligned prior to containment failure.	Lack of credit for these systems represents a realistic assessment just as credit for Condensate is appropriate given its location in the Turbine Building. This should not be a source of model uncertainty in most applications. It is treated appropriately as an HEP model uncertainty in Section F.6 and as part of the phenomenological uncertainties (see discussion below under 4)).
				4) Following containment failure, injection from Condensate could still be maintained, but if a large containment failure occurs, injection paths may be disrupted leading to loss of these external sources. This failure probability is based on a detailed structural analysis of the Mark I containment design and large scale ultimate failure testing of steel containments.	4) Condensate is credited for success after containment failure, but an additional basic event is included that represents the likelihood that the containment failure size and location disrupts the capability of Condensate to inject.	Condensate injection capability after large catastrophic containment failure is treated conservatively and is not identified as a candidate source of model uncertainty.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
8. (cont'd)			<u>Containment Vent Success</u> With containment venting successful for controlled, hard pipe vent cases, there are a significant number of sources available to maintain RPV injection: – Condensate – CRD – LPCI – CS – FPS Reactor Building and Turbine Building environments remain acceptable, and SRVs remain open.	1) It is assumed that injection sources from the suppression pool are likely to survive since a controlled containment depressurization could occur in these cases compared to the containment failure cases.	1) LPCI and Core Spray are not credited for success after uncontrolled containment venting.	No credit for systems with suction from the torus after uncontrolled containment venting represents a slight conservative bias. This should not be a source of model uncertainty in most applications. It is treated appropriately as an HEP model uncertainty in Section F.6.
				2) Potentially viable injection systems post-venting include CRD, Condensate, Fire Water, along with LPCI and CS from the CST.	2) Logic is included in the post-venting portion of the event sequence modeling for providing RPV injection from these systems.	Realistic treatment of RPV makeup is used. This should not be a source of model uncertainty in most applications. It is treated appropriately as an HEP model uncertainty in Section F.6.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
8. (cont'd)				3) Hard pipe vent conditions will not result in degraded Reactor Building or Turbine Building conditions. Therefore, local actions are not significantly impacted.	3) Local line ups of systems including LPCI/CS from CST can be included.	3) Realistic modeling used in the hard pipe vent case. The probabilities used in characterizing the local line ups of alternate systems are judged to be slightly conservative. Therefore, This should not be a source of model uncertainty in most applications. It is treated appropriately as an HEP model uncertainty in Section F.5.
				4) Use of vent paths via duct work in the Reactor Building ("soft" vent) may create adverse environmental conditions in the Reactor Building. Because no specific direction is included to line-up the alternate injection systems prior to "soft" venting containment, the conditions in the reactor building post-venting are assumed to preclude their use.	4) A separate basic event for lining up alternate injection from LPCI & CS prior to "soft" venting via duct work is included in the model that is currently set to guaranteed fail.	No credit for these systems after "soft" containment venting represents a slight conservative bias treatment. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
9. Room heatup calculations	Loss of HVAC can result in room temperatures exceeding equipment qualification limits. Treatment of HVAC requirements varies across the industry and often varies within a PRA. There are two aspects to this issue. (1) One involves whether the SSCs affected by loss of HVAC are assumed to fail (i.e., there is uncertainty in the fragility of the components). (2) The other involves how the rate of room heatup is calculated and the assumed timing of the failure.	Dependency on HVAC for system modeling and timing of accident progressions and associated success criteria.	A combination of design basis calculations for technical specifications and supporting calculations are referenced to determine the HVAC requirements in the model.	1) Electrical switchgear HVAC is not required for extended times because of the large open spaces for the equipment in the switchgear and battery rooms are sufficiently applicable to the anticipated transients in the PRA model.	1) An HVAC dependency is not included for the switchgear and battery rooms.	This is judged to be realistic and consistent with operating experience. This should not be a candidate source of model uncertainty.
				2) HPCI, Core Spray, and LPCI require the room cooling for success.	2) An HVAC dependency for Core Spray and LPCI is included in the system models. HVAC dependencies for HPCI, LPCI, and CS are included for operation of these systems.	Realistic evaluation. This should not be a source of model uncertainty in most applications. Realistic with slight conservative bias. This should not be a source of model uncertainty in most applications.
				3) Control Room: During SBO events, Hope Creek Operating Abnormal procedures direct opening all panel doors and two of the security doors for the duration of the event.		Realistic evaluation.
				4) Other Systems: See Dependency Notebook for room cooling requirements.	5) Support systems included in model as appropriate.	Realistic evaluation. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
10. Battery life calculations	Station Blackout events are important contributors to baseline CDF at nearly every US NPP. Battery life is an important factor in assessing a plant's ability to cope with an SBO. Many plants only have design basis calculations for battery life. Other plants have very plant/condition-specific calculations of battery life. Failing to fully credit battery capability can overstate risks, and mask other potentially contributors and insights. Realistically assessing battery life can be complex.	Determination of battery depletion time(s) and the associated accident sequence timing and related success criteria. This primarily involves LOOP accident sequences.	Design basis calculations support the 4 hour battery life. No load shed requirement to preserve battery life.	Load shed is not needed to achieve the battery life time of 4 hours.	CRD is only credited in SBO scenarios if HPCI or RCIC is available to provide initial injection because CRD is not viable as the only makeup source until approximately 4 hours after sequence initiation, and then only if AC power is restored.	The SBO design basis of a 4 hour battery life is used in the PRA model. Because of the slightly conservative quantitative estimates, this should not be a source of model uncertainty in most applications.
11. Number of PORVs required for bleed and feed – PWRs	PWR EOPs direct opening of all PORVs to reduce RCS pressure for initiation of bleed and feed cooling. Some plants have performed plant-specific analyses that demonstrate that less than all PORVs may be sufficient, depending on ECCS characteristics and initiation timing.	System logic modeling representing success criterion and accident sequence timing for performance of bleed and feed and sequences involving success or failure of feed and bleed.	N/A	N/A	N/A	N/A

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
12. Containment sump / strainer performance	All PWRs are improving ECCS sump management practices, including installation of new sump strainers at most plants. There is not a consistent method for the treatment of ECCS sump performance. All BWRs have improved their suppression pool strainers to reduce the potential for plugging. However, there is not a consistent method for the treatment of suppression pool strainer performance.	Recirculation from sump (PWRs) or from the suppression pool (BWRs) system modeling and sequences involving injection from these sources. (Note that the modeling should be relatively straightforward, the uncertainty is related to the methods or references used to determine the likelihood of sump strainer and common cause failure of the strainers.)	***The failure cause and likelihood of suppression pool suction strainers are expected to be significantly different, depending on what type of accident sequence is being analyzed.*** Therefore, global scenario-specific CCF terms for all suppression pool strainers are included in the model.	1) A global CCF of all suppression pool strainers (i.e., HPCI, RCIC, CS, and 4 LPCI) is highly unlikely, but cannot be totally dismissed. There are different CCF global values utilized for LOCAs (1.0E-4), IORV or emergency depressurization case (1.0E-5), and general transients (1.0E-6) based on engineering judgment. These global failures are assumed to be unrecoverable.	1) Unrecoverable scenario based global CCF terms are utilized in the model for simultaneous failure of all suppression pool strainers.	The incorporation of unrecoverable global CCF term for simultaneous clogging of all suppression pool strainers is judged to represent a slightly conservative bias. This should not be a source of model uncertainty in most applications.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
13. Impact of failure of pressure relief	Certain scenarios can lead to RCS/RPV pressure transients requiring pressure relief. Usually, there is sufficient capacity to accommodate the pressure transient. However, in some scenarios, failure of adequate pressure relief can be a consideration. Various assumptions can be taken on the impact of inadequate pressure relief.	Success criterion for prevention of RPV overpressure. (Note that uncertainty exists in both the determination of the global CCF values that may lead to RPV overpressure and what is done with the subsequent RPV overpressure sequence modeling.)	Failure of a sufficient number of safety relief valves to open when required may lead to excessive reactor vessel pressure and a potential LOCA condition. The success criteria for the reactor pressure control function is established for various scenarios since the number of the relief valves required to open (or relief valve capacity) varies for different accident sequences.	1) For general transients (non-ATWS), it is assumed that 1 of the SRVs is required to lift early to preserve RPV integrity below Service Level C. This is conservatively based on the post-trip emergency depressurization success criteria.	1) The actual number of SRVs required to open is insignificant since the dominant failure mechanism is common cause failure of the SRVs where groups of six or more are typically treated as global common cause failures. The global CCF value is based on available generic failure rates from observed operating experience events.	Slight conservative bias treatment in extension of CCF factors. This should not be a source of model uncertainty in most applications.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
13. (cont'd)				2) The success criterion for Large LOCA is suitably equivalent to the impacts of failure of overpressure relief.	2) Transient (non-ATWS) cases with overpressure failures are transferred to the Large water LOCA below TAF event tree.	Postulated overpressure failure mode being equivalent to Large LOCA success criteria is slightly conservative because the break is likely to occur at a penetration or other local area where the size will be limited. The ductile nature of the RPV will likely preclude the "crack running". In addition, the excessive LOCA initiator already adequately addresses the possibility that a larger break size is induced. Therefore, this should not be a source of model uncertainty in most applications.
				3) Based on plant-specific calculations and reference to generic analysis, it is assumed that most SRVs are required for successful overpressure mitigation in ATWS scenarios.	3) One basic event is included in the model representing the total failure probability that 3 or more SRVs fail to open to provide overpressure protection with the value determined from generic failure rates and alpha factors.	Slight conservative bias treatment in assumption of 100% ATWS conditions for the calculation. This should not be a source of model uncertainty in most applications.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
13. (cont'd)				4) In ATWS scenarios, failure of the vessel pressure relief function is assumed to cause a LOCA that would challenge low pressure ECCS to replenish coolant inventory. The subsequent injection of cold un-borated water under ATWS conditions is assumed to cause re-criticality, eventually leading to core damage.	4) In the ATWS event tree, unmitigated ATWS scenarios with overpressure failure are assigned as core damage sequences.	Realistic treatment in assumption that overpressure failure in ATWS cases goes directly to core damage. This should not be a source of model uncertainty in most applications.
				5) ARI is assumed to successfully terminate the ATWS event after electrical scram failures, but not before LOCA conditions have occurred if overpressure failures also occur.	5) These sequences are transferred to the Large LOCA below TAF event tree for completeness, but are not anticipated to significantly contribute to the Large LOCA frequency given the low probability of occurrence of this exact sequence of events.	Postulated overpressure failure mode being equivalent to Large LOCA success criteria is slightly conservative because the break is likely to occur at a penetration or other local area where the size will be limited. The ductile nature of the RPV will likely preclude the "crack running". In addition, the excessive LOCA initiator already adequately addresses the possibility that a larger break size is induced. Therefore, this should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
Systems Analysis (to support meeting SY-C3 which replaced SY-C3 from the ASME PRA Standard)						
14. Operability of equipment in beyond design basis environments	Due to the scope of PRAs, scenarios may arise where equipment is exposed to beyond design basis environments (w/o room cooling, w/o component cooling, w/ deadheading, in the presence of an un-isolated LOCA in the area, etc.).	System and accident sequence modeling of available systems and required support systems	Generally, there is no credit for operation of systems beyond their design-basis environment.	– In general, the PRA does not credit equipment operation beyond its design basis envelope. However, to maintain realism in the PRA, equipment failure is not necessarily assumed when this is exceeded. – BOP systems are credited in the PRA. These equipment do not usually have an EQ envelope. Therefore, operation of these equipment will always be outside their "EQ envelope". – Exceeding the EQ envelope does not constitute failure. It may be indicative of a higher failure rate. The survivability of equipment is justified based upon reasonable estimates of equipment operability with modest extensions of normal operating conditions or modest extensions of EQ envelopes. These applications of existing analysis to the PRA model are documented in the Dependency Notebook.	Severely degraded plant conditions may impose environmental conditions that are beyond the design basis envelope. These conditions may lead to higher failure rates. Models affected include Reactor Building equipment after containment failure.	The Class II events (containment failed) doe not contribute to the application specific delta-risk. This is not retained as a candidate model uncertainty.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
Human Reliability Analysis (to support meeting HR-I3 which replaced HR-I3 from the ASME PRA Standard)						
15. Credit For ERO	Most PRAs do not give much, if any credit, for initiation of the Emergency Response Organization (ERO), including actions included in plant-specific SAMGs and the new B5b mitigation strategies. The additional resources and capabilities brought to bear via the ERO can be substantial, especially for long-term events.	System or accident sequence modeling with incorporation of HFEs and HEP value determination in both the Level 1 and Level 2 models	Generally, credit for initiation of actions from the ERO is not taken in the Level 1 core damage sequence analysis. Exceptions are noted in the next column. Credit for the SAMGs is taken in the detailed Level 2 analysis.	1) Since containment venting would typically not be directed until 15-20 hours after sequence initiation given loss of decay heat removal scenarios, a recovery factor on the cognitive portion of the containment vent HEPs include credit for ERO response. 2) Level 2 HRA has included credit to implement SAMGs for: - DW sprays - RPV breach detection - Cont. flooding	1) Per the HRA methodology, the cognitive portion of the containment vent HEP is adjusted, but the execution portion of the HEP is not adjusted. 2) Level 2 HRA	Credit for some direction from the ERO for this action is a realistic assumption. Minimal credit is imposed for the ERO presence in support of the Level 1 PRA. The Level 2 PRA relies on the ERO presence for effective SAMG implementation. The HRA Dependency "floor" limits the credit that can be achieved even when ERO is credited. This should not be a source of model uncertainty in most applications.

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ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
Internal Flooding (to support meeting IFPP-B3, IFSO-B5, IFSN-B3, IFEV-B3, IF-QU-B3 which replaced IF-B3 from the ASME PRA Standard)						
16. Piping failure mode	One of the most important, and uncertain, inputs to an internal flooding analysis is the frequency of floods of various magnitudes (e.g., small, large, catastrophic) from various sources (e.g., clean water, untreated water, salt water, etc.). EPRI has developed some data, but the NRC has not formally endorsed its use.	Likelihood and characterization of internal flooding sources and internal flood event sequences.	Internal flood analysis and initiating event frequencies for spray, flood, and major flood scenarios developed consistent with the EPRI methodology [F-6].	1) The use of generic flood frequencies with plant-specific estimates of pipe lengths is suitable for representation of the flood frequencies at the site.	1) Flood initiator frequencies are based on plant-specific estimates of pipe lengths and generic flood frequencies (per foot) for different categories of piping from the EPRI methodology [23].	Considered an industry good practice approach, but is not yet a consensus model approach. Therefore, this is a candidate model uncertainty.
				2) Spray flood scenarios with less than 100 GPM flow do not totally disable the system they arise from.	2) Spray initiator scenario impacts are limited to the local affects of the spray.	Realistic with a slight conservative bias employed in the undeveloped spray scenarios that are subsumed in with the other flood scenarios in the same region. This should not be a source of model uncertainty in most applications.
				3) Flood and major flood sources are assumed to totally disable the system they arise from.	3) Flood and major flood initiator scenarios include failure of the source system as well as the components that are failed due to the flood event.	Slight conservative bias in that the system may not be totally disabled in all cases. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
16. (cont'd)				4) Propagation paths are defined by drawings and walkdown.	4) There could be sneak paths not identified by design or walkdowns that could propagate flood to unanalyzed areas.	Internal Flooding is not a contributor to the delta-risk assessment for the EDG AOT extension. It is not retained as a candidate model uncertainty.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
LERF Analysis (to support meeting LE-G4 which replaced LE-G4 from the ASME PRA Standard)						
17. Core melt arrest in-vessel	Typically, the treatment of core melt arrest in-vessel has been limited. However, recent NRC work has indicated that there may be more potential than previously credited. A possible example is credit for CRD in BWRs as fully capable of arresting core melt progression in-vessel per MELCOR calculations.	Level 2 containment event tree sequences.	In LOOP/SBO events, credit for core melt arrest in-vessel prior to vessel failure is accounted for with adjustments to the LOOP fail to recover values based on only limited time available after core damage, i.e., the assumption is that once the debris begins to relocate, the core melt progression cannot be retained in-vessel.	1) In LOOP/SBO events, credit for core melt arrest in-vessel is based on the calculated times between core damage and the time beyond which vessel failure cannot be precluded. (Approximately 40 min.)	1) The corresponding differences in the failure to recover probabilities are included in the Level 2 event sequence modeling for LOOP/SBO without offsite power recovered at the time of core damage.	Realistic with slight conservative bias on the times chosen to restore offsite power to avoid vessel failure following core damage. This should not be a source of model uncertainty in most applications.
			Only marginal credit for recovery is taken for events that remain at high pressure between core damage and vessel failure.	2) Based on engineering judgment, a factor of 0.9 is assumed to be appropriate for the failure probability to use to credit core melt arrest in-vessel for cases with the RPV remaining at high pressure following core damage.	2) High pressure core damage scenarios with no subsequent RPV depressurization following core damage employ the 0.9 factor for failure to arrest core melt in-vessel in the Level 2 containment event tree sequences.	Core melt arrest in-vessel at high pressure may not be possible and therefore this could be a source of model uncertainty. However, the 0.9 factor compared to the alternative assumption of 1.0 should not have an impact on any applications. Therefore, changing the modeling approach would <u>not</u> cause the risk metrics to approach any acceptance guidelines.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
17. (cont'd)			If RPV depressurization occurs after core damage, but before the time at which vessel breach cannot be precluded, then core melt arrest in-vessel is credited if LP ECCS or SBCS injection is available.	3) Injection from these high capacity low pressure systems will preclude vessel failure if they are available following RPV depressurization but before the time at which vessel breach cannot be precluded given core damage occurs at high RPV pressure.	3) The most likely scenarios for terminating in-vessel core melt progression are for high pressure core damage sequences with subsequent successful RPV depressurization. Therefore, high pressure core damage scenarios with subsequent RPV depressurization following core damage determine the likelihood of core melt arrest in-vessel.	Core melt arrest prior to vessel failure may be credited to some degree with LP injection recovered after core damage, but prior to vessel failure. However, credit for the in-vessel arrest is limited to only a short amount of in-vessel core melt progression. The credit for in-vessel recovery has a slight conservative bias. Therefore, the assumption of LP ECCS restoration assuring that vessel failure is avoided is not identified as a candidate source of model uncertainty.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
17. (cont'd)			If containment failure occurs prior to core damage due to dynamic containment loading failure (LOCA Class 3D and ATWS Class 4) i.e., in scenarios that could result in LERF, no injection is credited to provide core melt arrest in-vessel.	4) Failure modes are included for harsh reactor building environment or piping failures due to containment failure based on engineering judgment.	4) Core damage sequences that have LERF potential where containment failure occurs prior to core damage include logic in the core melt arrest in-vessel node for the hardware failures and the additional failure modes for harsh reactor building environment or piping failures.	The harsh reactor building environment factor following containment failure and piping failure value following containment failure are both identified as sources of model uncertainty. However, their treatment in the PRA model results in a guaranteed failure of RPV makeup. Therefore, changing the modeling approach would <u>not</u> cause the risk metrics to approach any acceptance guidelines. As a result, this is <u>not</u> included as a candidate modeling uncertainty.
18. Thermally induced failure of hot leg/SG tubes – PWRs	NRC analytical models and research findings continue to show that TI-SGTR is more probable than predicted by the industry. There is a need to come to agreement with NRC on the thermal hydraulics modeling of TI-SGTR.	Level 2 containment event tree sequences	N/A to Hope Creek BWR	N/A to Hope Creek BWR	N/A to Hope Creek BWR	N/A to Hope Creek BWR

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
19. Vessel failure mode	The progression of core melt to the point of vessel failure remains uncertain. Some codes (MELCOR) predict that even vessels with lower head penetrations will remain intact until the water has evaporated from above the relocated core debris. Other codes (MAAP), predict that lower head penetrations might fail early. The failure mode of the vessel and associated timing can impact LERF determination, and may influence DCH characteristics (especially for some BWRs and PWR ice condenser plants).	Level 2 containment event tree sequences	There are several phenomenological conditions that could lead to early containment failure (and LERF) that are dependent upon the vessel failure mode considered in the Level 2 analysis. These issues are: 1) RPV catastrophic failure, 2) direct containment heating, 3) ex-vessel steam explosion, 4) core-melt progression overwhelms vapor suppression capabilities or otherwise leads to containment failure, and 5) Pedestal differential pressure causes structural failure and loss of containment integrity.	1) RPV catastrophic failure leading to early containment failure via missiles or pedestal failure is extremely unlikely based on reference to generic studies and identification of plant-specific features. Level 1 and 2 PRA includes this failure mode.	1) Failure modes considered in model for missile failures and pedestal failure for sequences that proceed to vessel failure.	Phenomenological failure probabilities included in the Level 1 and Level 2 chosen represent a slight conservative bias given the current understanding of these issues. This should not be a source of model uncertainty in most applications.
				2) Direct containment heating only possible for high pressure melt scenarios, but noted as very unlikely in high pressure melt scenarios based on reference to generic BWR studies and identification of plant-specific features.	2) DCH failure mode considered in model for sequences that proceed to vessel failure at high pressure.	Phenomenological failure probabilities chosen represent a slight conservative bias given the current understanding of these issues. This should not be a source of model uncertainty in most applications.
				3) Ex-vessel steam explosions within the drywell pedestal sufficient to cause containment failure noted as very unlikely based on reference to generic studies and identification of plant-specific features.	3) Ex-vessel steam explosion failure mode considered in model for sequences that proceed to vessel failure.	Phenomenological failure probabilities chosen represent a slight conservative bias given the current understanding of these issues. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
19. (cont'd)				4) Ex-vessel core melt progression overwhelms vapor suppression noted as extremely unlikely for low pressure RPV failures modes and very unlikely for high pressure failure modes based on reference to generic studies and identification of plant-specific features.	4) Ex-vessel core melt progression overwhelms vapor suppression is explicitly considered in model for low pressure RPV failure sequences and high pressure RPV failure sequences.	Ex-vessel core melt progression overwhelms vapor suppression capabilities is not identified as a candidate source of model uncertainty. This modeling approach is judged to be slightly conservative and is <u>not</u> judged to lead to challenging any acceptance guidelines. Therefore, this is not a candidate modeling uncertainty.
				5) Ex-vessel core melt progression with water available to the debris leads to potentially safe conditions (containment intact) if other safety functions can be performed (e.g., containment heat removal, containment pressure control, makeup, combustible gas control). This is judged to be realistic.	5) Phenomenological failure modes, shell failure, and slow over pressure failures explicitly evaluated.	This phenomena is deterministically modeled. Therefore, this is not a candidate modeling uncertainty.
				6) RPV blowdown at high and low RPV pressure has been deterministically modeled and the differential pressure across the pedestal wall found to be within the realistic ultimate capability of the RPV pedestal.	6) The pedestal failure is assigned a very low failure probability for low RPV pressure core melt progression and only a slightly higher failure probability for high pressure core melt progression.	Based on the deterministic calculation this is not judged to be a candidate modeling uncertainty.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
20. Ex-vessel cooling of lower head	The lower vessel head of some plants may be submerged in water prior to the relocation of core debris to the lower head. This presents the potential for the core debris to be retained in-vessel by ex-vessel cooling. This is a complex analysis impacted by insulation, vessel design and degree of submergence.	Level 2 containment event tree sequences	Containment flooding is procedurally directed in most core damage scenarios. However, given the Mark I containment design, no credit is taken for flooding containment in time to prevent vessel failure via ex-vessel cooling of the lower RPV head. Incorporation of containment flooding is only included in the full Level 2 model to differentiate some of the non-LERF release categories.	1) Ex-vessel cooling of the lower head cannot occur quickly enough to prevent vessel failure and the potential for LERF scenarios.	1) Ex-vessel cooling of the lower head is not included in the model.	No credit for ex-vessel cooling of the lower head represents a realistic treatment with a slight conservative bias. Therefore, changing the modeling approach would <u>not</u> cause the risk metrics to approach any acceptance guidelines. This should not be a source of model uncertainty in most applications.
21. Core debris contact with containment	In some plants, core debris can come in contact with the containment shell (e.g., some BWR Mark Is, some PWRs including free-standing steel containments). Molten core debris can challenge the integrity of the containment boundary. Some analyses have demonstrated that core debris can be cooled by overlying water pools.	Level 2 containment event tree sequences	There are some postulated failure modes that could result in some debris reaching the Mark I shell.	This issue is explicitly modeled and quantified consistent with the assessment performed by Theofanous in NUREG/CR-5423 [F-11] and NUREG/CR-6025 [F-12].	There is significant impact on LERF assessment associated with this modeling.	The approach is considered realistic. Modeling uncertainty exists primarily on reducing the LERF risk metric. Modeling uncertainty is not expected to challenge any acceptance guidelines for anticipated applications. This is not retained as a candidate modeling uncertainty. This should not be a source of model uncertainty in most applications.

Table F-1

ISSUE CHARACTERIZATION FOR SOURCES OF MODEL UNCERTAINTY FOR HOPE CREEK (QU-F4 AND LE-F3)

Topic (to meet QU-E1)	Discussion of Issue	Part of Model Affected	Plant-Specific Approach Taken	Assumptions Made (to meet QU-E2)	Impact on Model (to meet QU-E4)	Characterization Assessment
22. ISLOCA IE Frequency Determination	ISLOCA is often a significant contributor to LERF. One key input to the ISLOCA analysis are the assumptions related to common cause rupture of isolation valves between the RCS/RPV and low pressure piping. There is no consensus approach to the data or treatment of this issue. Additionally, given an overpressure condition in low pressure piping, there is uncertainty surrounding the failure mode of the piping.	ISLOCA initiating event sequences	Detailed ISLOCA analysis includes the relevant considerations listed in IE-C12 of the ASME/ANS PRA Standard and accounts for common cause failures and captures likelihood of different piping failure modes.	1) Common cause beta factors from NUREG/CR-5497 [24] are utilized for the MOVs and CVs that comprise potential ISLOCA pathways. 2) The failure probability for each flow path given exposure to high pressure RPV conditions is appropriately represented by the formulae in NUREG/CR-5603 [F-7].	1) One ISLOCA initiating event frequency is implemented in the model representing the sum of all of the individual flow paths analyzed for rupture initiating event frequency. 2) Unique contributions from each flow path included in the model via a multiplier on the total ISLOCA initiating event frequency to delineate that fraction of system unavailability from the initiating event.	The approach for the ISLOCA frequency determination is considered an industry good practice, but is not yet considered a consensus model approach. Therefore, ISLOCA frequency is retained as a candidate model uncertainty.
23. Treatment of Hydrogen combustion in BWR Mark III and PWR ice condenser plants	The amount of hydrogen burned, the rate at which it is generated and burned, the pressure reduction mitigation credited by the suppression pool, ice condenser, structures, etc., can have a significant impact on the accident sequence progression development.	Level 2 containment event tree sequences	Mark I containment is generally inerted. For times when the containment is not inerted, severe accident progression is modeled to lead to hydrogen combustion which fails containment.	Generic historical data on time deinerted is applicable to future plant operation. Slightly conservative assessment of hydrogen combustion. The assumption that the time deinerted may correspond to a time of increased initiating event frequency (start up or shutdown) but a time of decreased decay heat generation is not included in the model quantification.	While HCGS is not a BWR Mark III, there is a small residual risk associated with hydrogen combustion. Because of the small window of deinerted operation. This failure mode is a minor contributor to the risk profile.	The approach is considered realistic. Modeling uncertainty exists primarily on reducing the LERF risk metric. Modeling uncertainty is not expected to challenge any acceptance guidelines for anticipated applications. This is not retained as a candidate modeling uncertainty. This should not be a source of model uncertainty in most applications.

F.5 CONSIDERATION OF PLANT-SPECIFIC FEATURES / MODELING APPROACHES

This portion of the assessment allows for the identification of any plant-specific features or unique phenomenological assessments not considered in the generic list of sources of modeling uncertainty in Appendix F.4.

There has been an extensive search for Hope Creek specific design or procedural features that may influence the modeling uncertainty. This plant specific search focused on a review of plant design and an in-depth review of the cutsets that contribute to the delta-risk associated with an EDG OOS condition. Appendix D provides the plant specific insights.

The plant specific insight results from Appendix D are provided in Table F-2. These identify the plant specific and application specific areas that could lead to modeling uncertainties.

Table F-2

SUMMARY OF POTENTIAL PLANT SPECIFIC UNCERTAINTIES IDENTIFIED FROM TIER 2 ANALYSIS TO EDG AOT EXTENSION APPLICATION

- LOOP initiating events due to switchyard maintenance
- Spurious breaker operation due to testing
- 125V DC battery failure due to testing
- Reliability of SACS
- Portable generator reliability
- EDG Failure Rates

F.6 SUMMARY

The results of implementing the process as shown in Table F-1 identified the following issues as the candidate sources of model uncertainty applicable to the base Hope Creek PRA model assessment.

Generic Modeling Uncertainties

- LOOP frequency and fail to recover probabilities (includes grid stability)
- HEPs and Dependent HEPs (see Appendix B)

Plant Specific Modeling Uncertainties

- LOOP initiating events due to switchyard maintenance
- Spurious breaker operation due to testing
- 125V DC battery failure due to testing
- Reliability of SACS
- EDG failure rates
- Portable generator reliability (see Appendix B)

For the most part, the issues listed above would need to be considered when trying to identify potential sources of model uncertainty relevant to an application being investigated per the guidance provided in Section 4 (see Figure 4-1) in the EPRI report [F-12]. Several other issues were also identified as being treated with conservative bias. These items are indicated in Table F-1, but due to the conservative treatment, they should not become potential candidates as key sources of uncertainty for most applications of the model.

Finally, the NRC/EPRI cooperative studies indicated an additional list of potential sources of uncertainty that should be addressed in applications to determine if they should be evaluated as key sources of uncertainty for such applications. This additional list of uncertainties is listed in Table F-3. Table F-3 lists the potential source of uncertainty and also identifies whether it should be considered for the candidate list of uncertainties for the EDG AOT extension request.

Table F-3

ADDITIONAL POSTULATED UNCERTAINTIES TO BE ADDRESSED ON AN APPLICATION SPECIFIC BASIS

Source of Uncertainty	To Be Evaluated for EDG AOT Request	Basis for Disposition
1. Treatment of boron dilution events.	No	Note [1]
2. Selection of prior distributions when carrying out a Bayesian analysis of data.	No	Note [2]
3. Treatment of rare and extremely rare events.	No	Note [3]
4. Moderator temperature coefficient – important in PWR ATWS.	N/A	Note [1]
5. Pressurized Thermal Shock – PWRs.	N/A	Note [1]
6. Credit for non-standard success paths (e.g., use of alternate injection systems).	Yes[(1)] (FPS Injection)	Note [5]
7. CDF and LERF definitions – the PRA standard allows some flexibility in defining these parameters.	No	Note [4]
8. Large LOCA long term oxidation in BWRs – since BWRs are designed to maintain 2/3 core height for a very large break LOCA, injection by one LPCI pump into the shroud area may maintain the covered core suF-cooled. Cooling of the top 1/3 core for a substantial time is questionable since long term steam cooling effect may not be ensured.	No	Note [3]
9. Engineering analyses – separate engineering analyses may use codes or invoke other assumptions that may introduce potential sources of modeling uncertainty.	No	Note [3]
10. Level control during ATWS in BWRs – difficult to perform, but more importantly, the power level achieved in different situations is uncertain. Power/flow oscillations can occur and its impact on the core is uncertain.	No	Note [3]
11. Post-LOCA boron precipitation in PWRs - modeled in design basis event thermal hydraulic evaluations, but is not always modeled in PRAs.	N/A	Note [1]
12. Digital instrumentation and control.	No	Note [3]

(1) Subsumed under the assessment of the portable generator.

Table F-3

ADDITIONAL POSTULATED UNCERTAINTIES TO BE ADDRESSED ON AN APPLICATION SPECIFIC BASIS

Source of Uncertainty	To Be Evaluated for EDG AOT Request	Basis for Disposition
13. Credit for non-safety related equipment in recovery actions.	Yes[(1)]	Note [5]
14. Passive system degradation mechanisms – aging of active components is incorporated into the periodic data analysis updates but passive system reliability is generally not accounted for.	No	Note [5]
15. Water hammer impacts on system performance.	No	Note [3]
16. Selection of components in a common cause group.	No	Note [6]
17. Capability of battery charger to start and carry loads if the battery is unavailable.	No	Note [3]
18. Standby failure rate model.	No	Note [3]

Table F-3 Notes:

Note [1] Not a BWR issue.

Note [2] Prior distributions are acceptable from industry data (e.g., NUREG/CR-6928).

Note [3] Does not influence the delta-risk for the EDG AOT extension application.

Note [4] CDF and LERF both have slightly conservative definitions relative to the ASME PRA Standard definitions.

Note [5] Slightly conservative approach taken for use of non-safety related equipment. Portable generator is subject of sensitivity.

Note [6] Slightly conservative grouping of common cause components leads to appropriate risk assessment.

(1) Subsumed under the assessment of the portable generator.

REFERENCES

[F-1] U.S. Regulatory Commission, *Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making,* NUREG-1855, Volume 1, Main Report, March 2009.

[F-2] ASME/American Nuclear Society, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," ASME/ANS RA-Sa-2009, March 2009.

[F-3] U.S. Nuclear Regulatory Commission Memorandum to Michael T. Lesar from Farouk Eltawila, "Notice of Clarification to Revision 1 of Regulatory Guide 1.200," for publication as a Federal Register Notice, July 27, 2007.

[F-4] *Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications*, (ASME RA-S-2002), Addenda RA-Sa-2003, and Addenda RA-SF-2005, December 2005.

[F-5] *Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments,* EPRI, Palo Alto, CA: November 2008 (Final). 1016737.

[F-6] Idaho National Laboratory, *Reevaluation of Station Blackout Risk at Nuclear Power Plants, Analysis of Loss of Offsite Power Events: 1986-2004*, NUREG/CR-6890, INL/EXT-05-00501, November 2005.

[F-7] Wesley, D. A. et al., *Pressure-Dependent Fragilities for Piping Compone*nts, NUREG/CR-5603, October 1990.

[F-8] Transmittal of Technical Work to Support Possible Rulemaking on a Risk-Informed Alternative to 10 CFR 50.46/GDC 35, Memo to Samuel J. Collins, NRC, from Ashok C. Thadani, NRC, dated July 31, 2002.

[F-9] *Pipe Failure Study Update*, TR-102266, EPRI, Palo Alto, CA, April 1993.

[F-10] U.S. Regulatory Commission*, Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP),* NUREG/CR-4832, Vols. 1-10, October 1990 - November 1993.

[F-11] Theofanous, T.G., et al., "The Probability of Liner Failure in a Mark I Containment," NUREG/CR-5423, 1989.

[F-12] Theofanous, T.G., et al., "The Probability of Mark I Failure of Melt – Attack of the Liner," NUREG/CR-60255, November 1993.

[F-13] *An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities*, Regulatory Guide 1.200, U.S. Nuclear Regulatory Commission, March 2009, Revision 2.

LIST OF REGULATORY COMMITMENTS

The following table identifies those actions committed to by PSEG in this document. Any other statements in this submittal are provided for information only purposes and are not considered to be regulatory commitments.

Regulatory Commitment	Committed Date	Commitment Type	
		One-Time Action (Yes/No)	Programmatic (Yes/No)
The following compensatory actions, which will be included in the TS Bases, will be applicable during the extended AOT for EDG A&B: 1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM). 2. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable. 3. When the "A" or "B" EDG is removed from service for an extended 14 day AOT, the remaining EDG in the same mechanical division (C or D, respectively) must be capable, operable and available to mitigate the consequence of a LOOP condition. 4. The removal from service of safety systems (e.g., HPCI or RCIC) and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT. 5. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT. 6. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.	Concurrent with approval and subsequent implementation of this proposed license amendment	No	Yes