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DEC 14 2016

LR-N16-0232

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

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

Subject: Response to Preliminary White Finding in Integrated Inspection Report No. 05000354/2016003; EA-16-184.

Reference: Hope Creek Generating Station Unit 1 – Integrated Inspection Report 05000354/2016003 and Preliminary White Finding, November 14, 2016.

By letter dated November 14, 2016 (Reference), the U.S. Nuclear Regulatory Commission (NRC) issued Inspection Report 05000354/2016003 completed on September 30, 2016.

The inspection report identified a preliminary White finding and associated apparent violation of Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," asserting that PSEG did not adequately implement an adverse condition monitoring procedure, specifically for performing monthly oil sampling of the High Pressure Coolant Injection (HPCI) system. As stated in the November 14, 2016 letter, PSEG has the option to submit additional information regarding the significance determination of this preliminary finding. Accordingly, we are submitting the attached additional information supporting our position.

There are no regulatory commitments associated with this submittal. If you have any questions, please contact Mr. Thomas MacEwen at (856) 339-1097.

Sincerely,

Eric Carr
Site Vice President
Hope Creek Generating Station

ttm

Enclosure: Additional Information Submitted Pursuant to Inspection Report 05000354/2016003, Preliminary White Finding

cc: Mr. D. Dorman, Regional Administrator, NRC Region I
Ms. C. Parker, Project Manager – Hope Creek
Mr. J. Hawkins, NRC Senior Resident Inspector - Hope Creek (X24)
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Enclosure

Additional Information Submitted Pursuant to Inspection Report 05000354/2016003, Preliminary White Finding

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Additional Information Submitted Pursuant to Inspection Report 05000354/2016003, Preliminary White Finding

1.0 Summary

NRC Finding Summary
The inspection report describes a self-revealing preliminary White finding and apparent violation because PSEG did not detect and act upon an adverse trend of water intrusion into the HPCI oil system. Specifically, PSEG did not adequately implement procedures to perform monthly HPCI turbine oil analysis for water contamination with known steam leakage by the Steam Admission Valve (FD-F001). The NRC screened the finding for safety significance and determined that a detailed risk evaluation (DRE) was required. The DRE was performed by a Region I senior reactor analyst (SRA) and concluded that the condition resulted in an increase in core damage frequency (CDF) of low E-6/yr, or of low-to-moderate safety significance (White). This result was obtained using the NRC's Standardized Plant Analysis Risk (SPAR) model for Hope Creek.

Hope Creek Response
PSEG agrees that the performance deficiency occurred. Hope Creek did not adequately implement procedures to perform monthly HPCI turbine oil analysis, did not identify significant moisture contamination in the HPCI oil system, and thus did not take the necessary response actions. As a result, the HPCI system was not able to perform its design function for a period greater than the fourteen days allowed by plant Technical Specifications.

PSEG has performed a Root Cause Evaluation that identified weaknesses in the Adverse Condition Monitoring (ACM) process, as well as in oversight of the ACM process and in individual performance and accountability to the process. Corrective actions to improve the ACM process and management oversight of the ACM process are being implemented.

PSEG appreciates the opportunity to present our perspective on the facts and assumptions used by the NRC to arrive at the significance level of the finding. PSEG does not agree with the characterization of the finding as low-to-moderate safety significance (White) and concludes the characterization of the finding should instead be one of very low risk significance (Green). This conclusion is based on a review of the SPAR model which identified many conservatisms and some inaccuracies in the modeling of plant equipment.

Performance Deficiency Characterization
PSEG performed a risk evaluation similar to the risk evaluation performed by the NRC senior reactor analyst. A review of the risk evaluation performed using Hope Creek Probabilistic Risk Assessment (PRA) models found significant conservatisms in the modeling approach. An extensive PSEG review determined that failure to credit equipment available to safely shutdown the plant, including secondary plant equipment, FLEX equipment and other defense-in-depth equipment, caused the unnecessarily conservative results. After an extensive analysis to incorporate this equipment into the internal events and fire PRAs, PSEG concludes that the risk increase associated with the HPCI failure is much lower than that originally calculated by PSEG and much lower than described in the referenced NRC inspection report. Following review of PSEG models, a review of the NRC model was conducted and found similar conservatisms and some inaccuracies in the modeling of plant equipment. PSEG is providing those results to the NRC to better inform the risk evaluation of the HPCI system failure, and to enhance the accuracy of the NRC PRA model.

Following correction of the unnecessary conservatisms in the PRA models, the increase in CDF from both the internal and external events is 7.6E-7/yr, or of very low safety significance (Green). PSEG is requesting that the NRC use the PSEG risk assessment methodology and results when assessing the significance of the event. A more detailed discussion of the Hope Creek PRA models and comparison with the NRC SPAR model is attached in section 2.0, Review of PRA Analysis.

In addition, PSEG reviewed the HPCI system data from June 23, 2016, that was described in Sensitivity Case 4 of the inspection report. The inspection report described a concern that water intrusion could have affected system operation as early as June 23, 2016, despite the successful system test that was performed on that date. The result of that review is being provided for NRC consideration and is contained in section 3.0, Review of Sensitivity Case 4, which concludes that the HPCI control system was able to perform its design functions during the June 23, 2016 test. As a result, PSEG believes the exposure time is most accurately identified as being 44 days.

2.0 Review of PRA Analysis

2.1 Purpose

The purpose of this section is to summarize PSEG's position on the risk increase associated with the unavailability of the HPCI system in July and August 2016. In its inspection report (05000354/2016003), the NRC discussed a finding that was preliminarily determined to be White under guidance associated with the Significance Determination Process (SDP). PSEG's initial risk calculations were generally consistent with this determination. However, further examination of the Hope Creek PRA models revealed significant conservatisms in the modeling approach; further review of the NRC models revealed similar conservatisms and additionally some errors.

2.2 Key Assumptions and Boundary Conditions

The following assumptions are applied for the HPCI degraded lube oil SDP risk evaluation:

- The SDP risk evaluation was performed based on the following:
    - As part of the determination process, an application-specific internal events risk model (ASM), HC116A-ASM was created based on the most recent internal events PRA Model of Record, HC111A. Development of this ASM included several revisions to better reflect the as-built, as-operated plant. This is referred to as the Full Power Internal Events (FPIE) model through the remainder of this document.
    - As part of the determination process, an application-specific fire risk model (ASM), HC114F0-ASM was created based on the most recent fire PRA Model of Record, HC114F0. Development of this ASM included several revisions to better reflect the as-built, as-operated plant. This is referred to as the Fire PRA (FPRA) model throughout the remainder of this document.
    - Seismic and other external events hazard contributors were reviewed in the Hope Creek Individual Plant Examination for External Events (IPEEE).

- Upon discovery that the HPCI system was inoperable on August 6, maintenance on the reactor core isolation cooling (RCIC) system was prohibited by Hope Creek guidance. The RCIC system was expeditiously protected by the control room operators and remained protected during the last 5 days of the 44 day unavailability. A more precise PRA calculation would eliminate the RCIC test and maintenance term and lower any risk increase calculations by 2-3%. For the purposes of this analysis, no credit is taken for the operator actions to protect the RCIC equipment. All calculations are shown for a 44 day interval.

- Repair and/or recovery of the HPCI system are not credited. Replacement of the HPCI hydro-electric governor (EGR) is a simple task, but this is not credited because of the uncertainty associated with the time necessary to troubleshoot the failure.

- Risk values in this document are generally presented showing 3 significant figures, which allows a reviewer to track exactly where in the ASM documents the risk value comes from. The reviewer should be aware that risks and changes in risk of the magnitudes generally discussed are accurate to one significant figure.

2.3 PRA Modeling

PSEG made preliminary modeling results available in time for NRC to incorporate this information into Inspection Report 05000354/2016003. Since that time, PSEG has undertaken a major effort to update our Fire and FPIE PRAs. This section describes the PRA model changes and then shows the best estimate calculations of risk increase. The risk increases are significantly lower than those discussed in the Inspection Report.

Initial review of the Hope Creek FPIE and FPRA models identified conservatisms compared to the as-built, as-operated plant. The area that yielded the biggest risk reduction was properly crediting shutdown using the secondary plant. The use of the main feedwater, condensate and turbine bypass systems was partially credited in the FPIE model and not credited in the Fire PRA (i.e., the secondary plant equipment was considered to be failed in all fire scenarios). As part of this effort the control and power cables for the secondary plant equipment were modeled and found to be routed through different fire areas than the RCIC control and power cables. The difference in the cable routing contributed to a significant reduction in the fire risk calculation. This robust design is now reflected in risk models. Other improvements included crediting newly installed FLEX equipment and incorporation of B.5.b. equipment that was only partially modeled in the last PRA updates.

Another modeling area that contained unnecessary conservatism was in the way RCIC failure to run, both from random failures and support system failures, was modeled. Hope Creek models were revised to include:

- Credit for injection from enhanced control rod drive (CRD) system after 4 hours of RCIC operation.
- Credit for battery charging from FLEX and B.5.b. diesels allowing long term operation of RCIC. These were credited for station blackout (SBO) scenarios, as well as for non-SBO scenarios involving random failures.

A few numeric changes to basic event probabilities were made, but the risk reduction was not as significant as changes made to properly credit equipment. The most important basic events, which are the operator failure to depressurize using automatic depressurization system (ADS) and random failures of RCIC, were reviewed and not changed.

Model of Record (MOR) values for CDF and Large Early Release Fraction (LERF) are compared with their respective ASM base case CDF and LERF values below in Table 1. These changes in risk metrics between the MOR and the ASM are the result of careful evaluation of each model's conservatisms and details.

Table 1

HOPE CREEK RISK MODEL COMPARISON

Category	Model Name	CDF	LERF
FPIE	HC111A	4.20E-6/yr	8.44E-7/yr
	HC116A-ASM	3.31E-6/yr	7.47E-7/yr
	[DELTA]	8.90E-7/yr	9.70E-8/yr
FPRA	HC114F0	2.18E-5/yr	3.08E-6/yr
	HC114F0-ASM	6.80E-6/yr	1.78E-6/yr
	[DELTA]	1.5E-5/yr	1.30E-6/yr

The baseline CDF changes are significant, especially in the case of the FPRA. The FPRA is a relatively immature model. Prior to the analysis associated with this SDP, the FPRA had not been seriously challenged to identify and remove conservatisms such as those identified below. Additionally, the model benefitted from recent NRC FAQs that were generally created and resolved by plants working on NFPA 805.

The FPIE model also contained conservatisms. Most were discovered by working with the Operations Department to ensure that the available equipment was properly credited. A FPIE model update is scheduled for 2017. The model update had been delayed awaiting complete installation of FLEX equipment and publication of NEI guidance for incorporating FLEX into a PRA model.

Changes to both PRA models are addressed under established processes governed by risk management procedures. Update Requirement Evaluations (UREs) have been created for both the FPIE and Fire PRA model adjustments to ensure those changes are incorporated in the next periodic updates.

The following describes the major changes to the models and the results of the PSEG analysis. The analysis packages are available for NRC review. All changes have been made in accordance with the PRA Standard (Reference 1), PSEG Risk management procedures and industry best PRA practice. They are permanent changes to the Hope Creek models.

<u>FPIE ΔCDF and ΔLERF Calculations</u>

The HC116A-ASM model features the following changes from the MOR:

- Fault Tree Changes:
  - RCIC success criteria with CRD available
  - Crediting of some FLEX procedures and equipment
  - SACS heat exchanger valves
  - MCC 10B421 cross-tie
  - Diesel generator undervoltage circuitry
  - Additional basic events

- Data Changes:
  - HPCI/RCIC room steam leak event
  - Dependent failure to operate high pressure systems
  - Suction strainer basic event calculation method
  - SRV accumulator leakage event

Base FPIE HC116A-ASM CDF = 3.31E-6/yr

FPIE CDF with HPCI OOS(1) = 8.63E-6/yr

FPIE ΔCDF = [(8.63E-6/yr) – (3.31E-6/yr)] * exposure time
= 5.32E-6/yr * [44 days / (365 days/yr)]
= 6.42E-7

Base FPIE HC116A-ASM LERF = 7.47E-7/yr

FPIE LERF with HPCI OOS(1) = 1.15E-6/yr

FPIE ΔLERF = [(1.15E-6/yr) - (7.47E-7/yr)] * exposure time
= 4.03E-7/yr * [44 days / (365 days/yr)]
= 4.86E-8

Fire PRA ΔCDF and ΔLERF Calculations

The HC114F0-ASM model features the following changes from the MOR:

- Additional model detail for hot short spurious actuation
- Radwaste area hoist scenario refined
- Restoration of circulating water pump house scenarios
- Fault tree, data adjustment, and basic event additions similar to the FPIE changes listed above.
- Incorporation of additional cable data for the following systems:
  - Condensate
  - Circulating Water
  - Feedwater
  - Instrument Air
  - Instrument Gas
  - 120 VAC Power Panels
  - Primary Containment
  - Reactor Auxiliaries Cooling
- Revised probabilities & calculations:
  - Human error probabilities
  - Non-suppression probabilities
- Targets revised in the following fire areas:
  - CD28
  - CD29
  - CD30
  - CD31

(1) Set Basic Event HPI-TDP-FS-OP204 (HPCI FTS term) to TRUE via flag file

Base Fire PRA HC114F0-ASM CDF = 6.80E-6/yr

Base Fire PRA CDF with HPCI OOS[(1)] = 7.76E-6/yr

Fire ΔCDF = [(7.76E-6/yr) - (6.80E-6/yr)] * exposure time
= 9.6E-7/yr * [44 days / (365 days/yr)]
= <u>1.16E-7</u>

Base Fire PRA HC114F0-ASM LERF = 1.78E-6/yr

Base Fire PRA LERF with HPCI OOS[(1)] = 1.91E-6/yr

Fire ΔLERF = [(1.91E-6/yr) – (1.78E-6/yr)] * exposure time
=1.38E-7/yr * [44 days / (365 days/yr)]
= <u>1.66E-8</u>

<u>Results</u>

The total ΔCDF is 6.42E-7 (FPIE) + 1.16E-7 (FPRA) = 7.57E-7.

The total ΔLERF is 4.86E-8 (FPIE) + 1.66E-8 (FPRA) = 6.52E-8.

2.4 Comments on the SPAR model analysis

NRC used the Hope Creek SPAR model to evaluate the internal events risk and clearly described their risk analysis in the referenced Inspection Report. Using Sensitivity Case 5, the NRC developed a refined best estimate delta CDF/yr of 2E-6, which is based on the sum of the internal events risk analysis, calculated from the SPAR model of 9.92E-7 and the PSEG-provided fire risk increase of 1.1E-6/yr. This section discusses the conservatisms in the SPAR model. The fire risk increase is based on a preliminary analysis that was made available to the NRC, as described in Section 2.3.

For sequences in which RCIC failed to run, the NRC adjusted the probability of operator failure to depressurize the reactor from 5E-4 to 1E-4. The adjustment was intended to account for the operator action and the inherent conservatism in using a 24 hour run time for RCIC. Given the simplified structure of the SPAR model and the simplified nature of the SPAR – Human Reliability Analysis Method (SPAR-H) being used to quantify human error probabilities, this approach is reasonable. Since the numeric change is a rough estimate based on SRA judgement, there is no conclusive way to quantify the validity of this adjustment. However, as discussed below, this numeric change does fully approximate the difference in RCIC failure rates and the failure to depressurize the reactor, which often appear in the same cutsets. The NRC calculated a change in CDF of 1.86E-6/yr using this modeling approach.

PSEG reviewed the calculations done by the NRC, and reproduced the calculations based on the NRC descriptions of the analysis. The NRC ran five sensitivity cases:

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(1) Set Basic Event HPI-TDP-FS-OP204 (HPCI FTS term) to TRUE via flag file

Sensitivity 1 (1.64E-6/yr): SSW 'B' Train Unavailable Due to Test & Maintenance
The SRA removed event SSW-SYS-TM-LOOPB from cutsets as a sensitivity case. This change alone reduced the change in CDF from 1.86E-6/yr to 1.64E-6/yr, or about 12%. This change should be part of the base case because it stems from an error in the SPAR model. This maintenance event is modeled in SPAR to immediately and completely remove the possibility of depressurizing using the ADS valves following a loss of offsite power (LOOP). The model is incorrect, because the ADS valves would be functional until battery depletion, which would be over 4 hours in a LOOP and over 6 hours if an extended loss of AC power (ELAP) is declared. Opportunities to charge the batteries with 10 CFR 50.54(hh)(2) equipment (usually called B.5.b equipment) or FLEX equipment, as well as the probability of recovering from the LOOP, are not credited in the SPAR model.

Sensitivity 2 (2.35E-6/yr): Basic SPAR run
This sensitivity analysis removes the improvements made in the base case described above and provides no additional information.

Sensitivity 3 (1.64E-7/yr): Additional Changes to Depressurization Probability
This is a further adjustment to the depressurization probability for the base case (depressurization probability = 1E-4) to this case (depressurization probability = 7.5E-5). The risk reduction of a 25% reduction in depressurization probability leads to a ~12% reduction in CDF increase. PSEG understands that the risk increase is very sensitive to the rare event probability that the operating crew fails to depressurize the reactor when required. PSEG reviewed and did not change the depressurization probability in the Hope Creek PRA model.

Sensitivity 4 (2.03E-6/yr): Full Exposure Time
The NRC performed this sensitivity calculation assuming an increased exposure time, including the failure to depressurize, as well as including failure to depressurize human error probability (HEP) changes but not including SSW B train adjustments. PSEG concludes that the HPCI system was operable on June 23, 2016, as discussed in section 3.0, Review of Sensitivity Case 4. Therefore, this sensitivity analysis is not appropriate for significance determination.

Sensitivity 5 (9.92E-7/yr): Changes to delete core damage sequences in question and adjust operator depressurization failure probability for fast acting initiating event (Medium Break LOCAs (MLOCA))
This sensitivity case comes closest to structurally matching the PSEG analysis, so it provides the best case for discussing the similarities and differences between the SPAR model and the PSEG PRA model.

The NRC deleted cutsets that contain LOOP events with SSW train B in test or maintenance. This should have been done for the base case and all sensitivity cases because that event is modeled incorrectly in the SPAR model, as discussed under sensitivity case 1. This unlikely maintenance activity is correctly modeled in the PSEG PRA.

The NRC revised the HEP for operator failure to depressurize event as was done in the base case, but not the rest of the sensitivity cases. The PSEG model uses 3.75E-4 as the probability of failing to depressurize using ADS following a transient or a LOOP. PSEG did not adjust the HEP for failure to depressurize for the RCIC failure to run scenarios but did model other relevant success paths, such as crediting enhanced CRD for decay heat removal and inventory control after 4 hours of RCIC success.

The NRC increased the operator failure to depressurize event probability to 2.75E-3 for MLOCA scenarios, which resulted in a slight risk increase. This approach was already used in the PSEG model, so no changes were necessary.

The NRC set RCI-MOV-FC-FRO (RCIC injection valve fails to reopen) to FALSE because this valve (BD-F013) would remain open with no automatic closure signal during RCIC operation. This valve is correctly modeled in the PSEG PRA, so no changes are needed. Since this change corrects a SPAR model error, all sensitivity cases should include this adjustment.

Reasons for the Differences between the PSEG PRA and the SPAR model

NRC sensitivity case 5 will be used to discuss differences and similarities between the SPAR analysis and the PSEG analysis. Case 5 was chosen because it includes corrections for errors identified in the SPAR model, making it a better choice for the basic comparisons. Case 5 lists the dominant sequences as:

- Loss of condenser heat sink, with failure to depressurize and RCIC in Test and Maintenance
- Loss of Main Feedwater, with failure to depressurize and RCIC in Test and Maintenance
- Loss of condenser heat sink, with failure to depressurize and RCIC failure to run
- Loss of condenser heat sink, with failure to depressurize and RCIC failure to start
- Loss of Main Feedwater, with failure to depressurize and RCIC failure to start

These scenarios are essentially identical to those in the PSEG analysis; the differences are in the quantification. The NRC calculates a ΔCDF of 9.9E-7/yr and PSEG calculates 6.4E-7/yr, resulting in a 35% difference. The major difference is caused by the difference in the probability of operators failing to depressurize using ADS. The basic NRC Human Error Probability (HEP) is 5E-4 while the PSEG HEP is 3.7E-4, a difference of 26%. This HEP (or a similar event) is in almost every cutset, so the difference in ΔCDF is almost proportional to the difference in HEP.

When analyzing HEPs that are relatively rare events (probability < 1E-2), Human Reliability Analyses (HRA) routinely vary by much more than the 26%. The SPAR-H HRA methods, used by the NRC, and the EPRI HRA calculator, used by PSEG, were benchmarked with many other methods in a broad international study completed over the last decade. Numerous examples of the variation between these and other methods can be found in "International HRA Empirical Study—Phase 1 Report: Description of Overall Approach and Pilot Phase Results from Comparing HRA Methods to Simulator Data" (NUREG/IA-0216, Vol. 1.) and several subsequent, related documents. The PSEG HEP analysis was reviewed and no changes were made for this SDP evaluation. The PSEG HEP analysis is unchanged from the latest formal peer review of the Hope Creek PRA, and is available for NRC review.

After the HRA differences, the major differences come from RCIC system reliability data. The PSEG test and maintenance unavailability for RCIC is 7.71E-3 compared to the SPAR unavailability for RCIC of 1.095E-2, a 30% difference. The PSEG value is based on data collected from PSEG plant specific maintenance rule records during the last PRA update.

Other differences include the SPAR models' use of higher failure rates for RCIC and no credit for using CRD injection after about 4 hours. Additionally, the SPAR models do not credit the possibility of using B.5.b or FLEX equipment to charge batteries and operate RCIC when the normal chargers are not available. These details are not normally credited in the SPAR models.

Conclusion on the SPAR analysis

NRC Sensitivity Case 5 gives similar results to the PSEG analysis because this case includes corrections to identified errors and conservatisms in the SPAR model. The difference in the ΔCDF values is clearly understood to be a result of different HRA models for a rare event, some differences in equipment reliability data and some simplifications in the SPAR model. None of these differences invalidates the SPAR model as an independent, confirmatory tool. In fact, the SPAR results confirm that the latest Hope Creek PRA results properly model the condition because the dominant ΔCDF cutsets and scenarios are very similar.

Summary of predominant analytic differences between plant and SPAR model:

- ADS is available for 4 to 6 hours following a LOOP (Battery life). The ADS function is being modeled as unavailable if B SSW Loop is in Test or Maintenance.
- ADS is available after 4 hours following a LOOP because B.5.b and/or FLEX equipment can be used to maintain batteries.
- RCIC system reliability uses the actual plant reliability values in the plant model
- RCIC injection valve (F013) failure to reopen should be removed from the base case, because this valve remains open following RCIC initiation.
- No credit is taken for CRD injection after 4 hours of successful RCIC operation.
- No credit is taken for FLEX or B.5.b equipment to restore RCIC batteries and maintain injection capability after 4 hours.

The HRA model and equipment reliability parameter calculations in the Hope Creek model were done in accordance with the PRA Standard and have been subjected to a peer review with no relevant Findings & Observations. Therefore, the latest PSEG internal events PRA model and fire PRA model should be used for input into the significance determination.

2.5 Seismic and Other External Hazards

Hope Creek does not maintain seismic, external flooding, or other external hazard PRAs. Seismic, external flooding, high winds, and other external hazards are discussed in the IPEEE (Reference 2).

A seismic risk study (PRA that falls short of current standards but provides clear, NRC reviewed insights) was performed for the IPEEE. The top five core damage sequences, labeled seismic damage states (SDS), are discussed in the IPEEE. The seismic risk is dominated by loss of instrumentation distribution panels. Two SDSs are relevant given a HPCI failure:

- SDS 26 is a seismic-induced LOOP followed by a failure of high pressure injection and random failures. The random failures are dominated by RPV depressurization failures and EDG failures resulting in an SBO. Given a HPCI failure, this SDS would become more significant, as there would be limited high pressure injection capability. However, station FLEX capability, which is not considered, should be able to effectively mitigate the SBO scenarios. This SDS contributes ~5% to seismic CDF.

- SDS 18 is a seismic induced LOOP with random failures resulting in core damage. Random failures are dominated by EDG failures resulting in an SBO. Neither random failures of high pressure injection nor failure to depressurize were the dominating failure in this SDS. Given a HPCI failure and SBO, RCIC is available on batteries for injection, and additional B.5.b and FLEX equipment would provide electrical backup for RCIC as well as low pressure injection.

The IPEEE review concluded that external hazards are not a significant risk contributor. The analysis provided also did not include newer station capabilities to mitigate external events with B.5.b and FLEX equipment. Seismic, high winds and external flooding risk would not be significantly impacted by HPCI being unavailable.

2.6 Conclusions

For the base case with a 44 day exposure time, the total ΔCDF is 7.57E-7. (6.42E-7 (FPIE) + 1.16E-7 (Fire PRA)) and the total ΔLERF is 6.52E-8. (4.86E-8 (FPIE) + 1.66E-8 (Fire PRA)). Thus, ΔCDF is <1E-6 and ΔLERF is < 1E-7, representing a finding of very low risk significance (i.e., Green).

Table 2

SUMMARY OF HOPE CREEK HPCI SDP RISK CALCULATIONS (BASED ON 44 DAY EXPOSURE TIME)

Case	FPIE PRA	Fire PRA	Total	Metric
ΔCDF Results	6.42E-7	1.16E-7	7.57E-7	< 1E-6
ΔLERF Results	4.86E-8	1.66E-8	6.52E-8	< 1E-7

PSEG performed three sensitivity analyses to evaluate differences between plant and SPAR models and to evaluate the benefit from FLEX equipment. The sensitivities were performed using the FPIE because the fire PRA is not the dominant contributor to the total risk increase. The three analyses were:

- Increase the depressurization HEP from the PSEG calculated probability to the SPAR model probability.
- Increase the RCIC failure to run probability from Hope Creek's calculated probability to the SPAR model probability.
- Remove credit for FLEX equipment.

None of these sensitivity analyses increased the delta risk to the thresholds for a White finding.

3.0 Review of Sensitivity Case 4

In Sensitivity Case 4 of the Inspection Report, the NRC discussed a concern that the data from the June 23, 2016, HPCI test show the control valve opened to around the 80 percent position on initial pressurization, which was further than observed on previous tests, and that it achieved a position of about 95 percent under the ramp generator control. This is greater than previous tests in which a control valve position of 40-55 percent was observed. The SRA expressed concern that this response created uncertainty in the length of the exposure time and therefore uncertainty in the increase in risk. However, as shown below the HPCI pump was able to perform its design functions during this test so there should be no change to the assumed exposure time of 44 days.

The HPCI start sequence is described in the EPRI NMAC Terry Turbine User's Manual, as follows: Once the auxiliary oil pump is started, the turbine oil relay hydraulic system will pressurize first. The turbine governor (control) valve will start to open. Next the governor's hydraulic system will pressurize and the turbine governor valve will start closing again. Then the hydraulic oil pressure will develop at the turbine stop valve's hydraulic cylinder and the stop valve leaves its closed position. The magnitude of the initial governor valve opening and the overall time period is dependent upon the drain down condition of the turbine's oil system. Once the stop valve leaves its closed position, the ramp generator signal and signal converter (RGSC) ramp circuit will be initiated and the voltage output will be increased in a positive direction.

During the HPCI System Start-up on June 23, 2016:

- Aux oil pump started
- The indicated position of the governor valve showed that the valve was open greater than expected
- The Pilot valve drove the governor valve towards the closed position in response to the remote servo and EGR as expected and IAW with EPRI NMAC Terry Turbine User's Manual
- At this time, flow indication and therefore turbine speed was still at zero prior to the governor valve moving towards the open position. (reference figure 1)
- Governor valve then began to open in response to the demand of the RGSC as part of the normal start-up sequence

The June 23, 2016, start-up sequence is consistent with the operation description from the EPRI Manual.

During the fall 2016 refueling outage, a visual and dimensional inspection of the HPCI pilot valve under was completed. The pilot valve was found to be in overall good condition, with light wear, and was reused.

The pilot valve's top, middle, and bottom control lands were inspected. The control land corners have light wear but are still sharp and free from burrs and nicks. Outside diameter measurements of the control lands were taken with a micrometer and met EPRI manual requirements. The lower control land had minor wear. The middle control land had approximately 20 minor score marks, which were lightly stoned to be removed. The top control land had very minimal wear. The bore of the pilot bushing was observed in good condition with minimal oil residue and no corrosion build up identified. No erosion or pitting was identified. The inside corners of the control ports were sharp and free from burrs and nicks. A swab was used to clean out the bushing bore. The inspection pictures show score marks on the pilot relay which are consistent with the anomalies observed in the governor valve stoke trace data from June 23, 2016.

As discussed above, the June 23, 2016 test results are consistent with the expected system response.

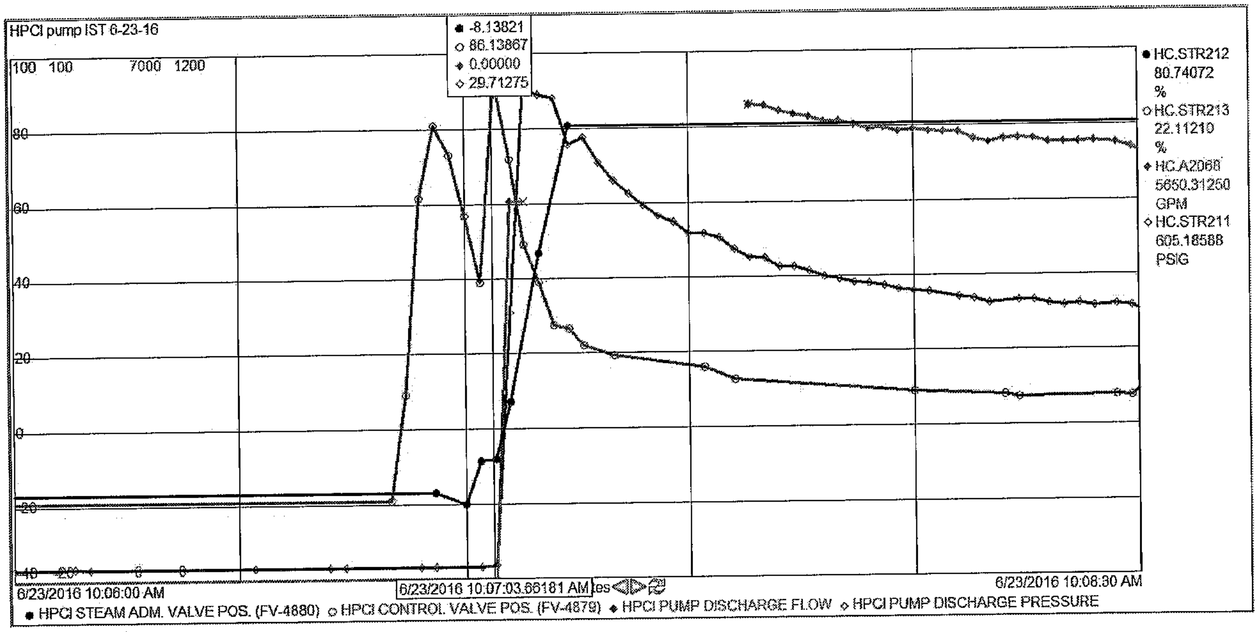

Figure 1: HPCI Test Data from June 23, 2016

3.1 Conclusions

A review of the EPRI summary of system operation shows that turbine governor valve will start to open, close, and then open again and the magnitude and time of this opening is dependent on system conditions. On June 23, 2016 the governor valve did open more than expected; however the data trace from June 23, shows it reopening in response to the RGSC control signal prior to turbine/pump rotation. The control system demonstrated that it was able to take control and respond normally. The plot of the HPCI starting sequence above shows this governor valve movement. The oil sample taken on that day had water content higher than the EPRI recommended limit, however from all of the parameters monitored it is concluded that the HPCI control system was able to perform its design functions during the June 23, 2016 test.

4.0 References

1. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RA-S-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.

2. Hope Creek Generating Station, Individual Plant Examination for External Events, Submittal Report, July, 1997.