UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD.
KING OF PRUSSIA, PA 19406-2713

February 6, 2017

EA-16-184

Mr. Peter P. Sena, III
President and Chief Nuclear Officer
PSEG Nuclear LLC – N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK GENERATING STATION – FINAL SIGNIFICANCE DETERMINATION FOR A WHITE FINDING WITH ASSESSMENT FOLLOW-UP AND NOTICE OF VIOLATION - INSPECTION REPORT 05000354/2016008

Dear Mr. Sena:

This letter provides you the final significance determination for the preliminary White finding discussed in the U.S. Nuclear Regulatory Commission (NRC) letter dated November 14, 2016, which included NRC Inspection Report Number 05000354/2016003 (ML16319A289).[1] The finding involved a failure by PSEG Nuclear, LLC (PSEG) to detect and act upon an adverse trend of water in the Hope Creek Generating Station (Hope Creek) High Pressure Coolant Injection (HPCI) oil system. As described in the subject inspection report, the NRC determined that this finding involved an apparent violation of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." This is because PSEG did not adequately implement procedure OP-AA-108-111, "Adverse Condition Monitoring (ACM) and Contingency Planning," and the ACM HC 15-008 action to perform monthly HPCI turbine oil sampling and analysis for water contamination with known steam leakage by a steam admission valve. As a result, on August 7, 2016, the HPCI governor control valve failed to stroke open as required due to moisture in the oil system degrading the internals of the Electric Governor – Remote (EG-R). As a consequence of this failure, PSEG also violated Technical Specification (TS) 3.5.1.c because the HPCI system was inoperable for a period greater than its TS-allowed outage time of 14 days.

In a letter dated December 14, 2016 (ML16349A604), PSEG provided a written response that acknowledged the finding but disagreed with the NRC's preliminary characterization of the finding as being of low-to-moderate (White) safety significance. Specifically, after further evaluation, PSEG identified conservatisms in the risk models used to assess the significance of this performance deficiency. PSEG subsequently revised their risk model to remove some of the conservative assumptions, as discussed in Enclosure 1, and stated in their letter that the significance of this finding should be of very low safety significance (Green). On December 21, 2016, NRC staff participated in a telephone call (ML17023A145) with PSEG staff to obtain clarification on some of the points raised by PSEG in the December 14, 2016, letter. Following

[1] Designation in parentheses refers to an Agency-wide Documents Access and Management System (ADAMS) accession number. Documents referenced in this letter are publicly-available using the accession number in ADAMS.

that discussion, PSEG submitted additional information in a letter dated January 3, 2017 (ML17003A319). A summary of PSEG's position as provided in its letters and in the telephone call, the NRC's response to the points raised by PSEG, and the details of the NRC's conclusion on the safety significance of this issue, are provided in Enclosure 1.

After careful consideration of the information developed during the inspection and the additional information provided in your December 14, 2016, letter; during the December 21, 2016 telephone call; and in your January 3, 2017, letter, the NRC has concluded that the finding is appropriately characterized as White, a finding of low to moderate safety significance. You have 30 calendar days from the date of this letter to appeal the NRC staff's determination of significance for the identified White finding. Such appeals will be considered to have merit only if they meet the criteria given in the NRC Inspection Manual Chapter 0609, Attachment 2. An appeal must be sent in writing to the Regional Administrator, Region I, 2100 Renaissance Boulevard, Suite 100, King of Prussia, PA 19406.

The NRC has also determined that the finding involved the violation of 10 CFR 50 Appendix B, Criterion V and TS 3.5.1.c, as cited in the attached Notice of Violation (Notice). In accordance with the NRC Enforcement Policy, the Notice is considered an escalated enforcement action because it is associated with a White finding. The NRC has concluded that the information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence, and the date when full compliance was achieved is already adequately addressed on the docket in NRC Inspection Report Number 05000354/2016003, in your letters dated December 14, 2016, and January 3, 2017, and in the summary of the December 21, 2016, telephone call. Therefore, you are not required to respond to this letter unless the description therein does not accurately reflect your corrective actions or your position.

As a result of this White finding in the Mitigating Systems Cornerstone, the NRC has assessed Hope Creek to be in the Regulatory Response column of the NRC's Reactor Oversight Process Action Matrix described in Inspection Manual Chapter 0305, "Operating Reactor Assessment Program," retroactive to the third calendar quarter of 2016. The NRC plans to conduct a separate supplemental inspection for this finding in accordance with Inspection Procedure 95001, "Supplemental Inspection Response to Action Matrix Column 2 Inputs," following PSEG's notification of readiness for this inspection. This inspection is conducted to provide assurance that the root causes and contributing causes of any performance issues are understood, the extent of condition is identified, and the corrective actions are sufficient to prevent recurrence.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice and Procedure," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

Should you have any questions regarding this matter, please contact Mr. Fred Bower, Chief, Projects Branch 3, Division of Reactor Projects in Region I, at (610) 337-5200.

Sincerely,

Daniel H. Dorman
Regional Administrator

Docket No. 50-354
License No. NPF-57

Enclosures: As stated

cc w/encl: Distribution via ListServ

ENCLOSURE 1

NRC RESPONSE TO INFORMATION PROVIDED IN THE PSEG NUCLEAR, LLC (PSEG) LETTERS DATED DECEMBER 14, 2016, AND JANUARY 3, 2017, REGARDING A HIGH PRESSURE COOLANT INJECTION FINDING

Summary of PSEG Response

In its December 14, 2016 letter, PSEG stated that the finding discussed in NRC Inspection Report 05000354/2016003, related to the failure of the high pressure coolant injection system (HPCI), should be characterized as being of very low safety significance (Green) rather than of low-to-moderate safety significance (White). In support of this assertion, PSEG developed significant revisions to their Fire and Full Power Internal Events (FPIE) probabilistic risk assessment (PRA) models. PSEG's major points included:

- 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 Reactor Core Isolation Cooling (RCIC) control and power cables. The difference in the cable routing contributed to a significant risk reduction in the fire risk calculation.

- PSEG's Risk Significance Determination, HC-SDP-007, Rev. 0, Section 4.0, PRA MODELING, documented that the models were conservative and were subsequently revised to include credit for: 1) enhanced injection flow from the control rod drive (CRD) system after 4 hours of RCIC operation; and, 2) battery charging from diverse and flexible coping strategies (FLEX) and B.5.b diesels, allowing long term operation of RCIC. HC-SDP-007 stated these were credited for station blackout (SBO) scenarios, but not credited for non-SBO scenarios involving random failures.

- The Automatic Depressurization System (ADS) would be available after 4 hours following a loss-of-offsite-power (LOOP) because of B.5.b and/or FLEX being available to maintain the station batteries, along with restoration of the RCIC batteries to maintain injection capability.

- There are errors and conservatisms embedded within the Standardized Plant Analysis Risk (SPAR) model such as a RCIC Injection valve (F013) failure to re-open event, which should be removed from the base case because this valve would remain open following RCIC initiation; and the maintenance event involving Salt Service Water (SSW) Train 'B' is incorrectly modeled in SPAR to immediately and completely remove the possibility of depressurizing using the ADS Valves following a LOOP (the ADS valves would be functional until battery depletion). Additionally, the SPAR models use more conservative failure rates for RCIC.

- PSEG determined that there would not be a significant impact on seismic, high wind, or flooding risk. PSEG also stated that the HPCI control system, based on a review of system data, was able to perform its design function during the last surveillance flow test performed on June 23, 2016.

NRC RESPONSE

The NRC staff reviewed and agree with some of the points raised by PSEG; however, the staff has determined that the proper characterization of this finding overall remains of low-to-moderate safety significance (White), as discussed below.

The original change in fire risk alone due to the HPCI failure was estimated by PSEG as an increase in core damage frequency (CDF) of a nominal 1E-6/yr prior to the issuance of the NRC inspection report. A significant effort was undertaken by the PSEG staff to revise the best estimate risk for external fire events, which led to a reduction in the external fire risk contribution to a nominal 1.16E-7/yr. The NRC performed a limited, in-office review of the revision to the external fire risk, noting that it would not impact our overall assessment of this event, and, as such, elected to incorporate PSEG's revised estimate into our assessment of this finding. However, the NRC staff did not perform a rigorous review of this change, and the limited use of this estimate to help assess the significance of this inspection finding should not be interpreted as the NRC taking any type of position related to the adequacy of the revised fire risk estimate or its potential use in future risk applications.

The NRC staff reviewed the bases for the contention that the CRD system should be credited for enhanced injection after 4 hours of RCIC operation. The NRC staff agreed that due to the reduction in decay heat, procedural guidance, and training, the RCIC failure to run basic event should be modified consistent with how PSEG modified the event, breaking down the RCIC fail-to-run into 4 hours and crediting the CRD system through the use of an 'AND' logic gate with the RCIC failure to run 24 hour basic event. This would more accurately represent the event vice any adjustment made to the operator failure to depressurize event. This was applied to both the base case and conditional case for the HPCI failure for all applicable events.

Additionally, a post-processing rule was developed in the SPAR model to perform a sensitivity adjustment consistent with HC-SDP-007, Rev. 0 for some credit for battery charging for SBO scenarios. A FLEX basic recovery event with a failure probability of 0.1 was used consistent with the statement in HC-SDP-007, applying some credit for longer term operation of equipment, such as RCIC. This was applied to both the base case and conditional case for the HPCI failure. This was found not to have a significant impact on the results, consistent with PSEG's third sensitivity run within HC-ASM-003, Revision 0, Application Specific Model HC116A-ASM to Support HPCI HC-SDP-007. However, the NRC's use of the 0.1 value should not be interpreted as the NRC taking any type of position related to the adequacy of the revised failure probability or its potential use in future risk applications.

The NRC staff agrees and acknowledges that several of the SPAR model assumptions which were originally significant contributors to risk do not appear warranted. This was previously noted and reflected in the original risk determination as Sensitivity Case 5 for the original detailed risk evaluation for Inspection Report 05000354/2016003. The SPAR model basic events "RCIC injection valve F013 failure to re-open" and "'B' SSW in test and maintenance" contributors to CDF core damage sequences were removed from both the base case and conditional case for risk model runs as part of this evaluation as well. This was performed by deleting any sequences with these basic events. Additionally, the "RCIC room steam leak" event was modified from 0.1 to 0.01. NUREG 1275, "Operating Experience Feedback Reports," Volume 10, Section 5.2 acknowledges that HPCI and RCIC historically have experienced demands on the order of about once every 2.5 reactor-years. Thus, most failure data (such as that discussed within Section 7 of that report), and historical evidence of turbine operability, are primarily derived from surveillance testing. This testing varies in both frequency and methodology, and in some cases may not closely simulate the dynamic response assumed for the safety function of the standby pump as addressed in Section 6.0 of that report. The NRC staff has discussed with PSEG the significant challenge to the control systems based on actual injection events versus normal surveillance testing with the PSEG staff, and thus decided to use the SPAR model RCIC failure data in this SDP.

The NRC staff ran a surrogate internal event sequence for seismic-initiated LOOP events, and this resulted in a conditional increase in risk in the E-9/yr range. The NRC staff agrees with PSEG's assessment that no significant impact existed outside of fire events.

Regarding the exposure time of the failed condition, the NRC staff performed a thorough review of plant computer plots during system operation, vendor information describing the turbine governor oil relay and linkage system operation, and PSEG's assessment of hydraulic components within LR-N16-0232 and condition reports. During the start of the auxiliary oil pump, the turbine relay system is designed to pressurize first, with the oil relay pilot valve, oil relay power cylinder, interconnecting beam relay linkage all driven by the governor remote servo position, which transmits movement from the electronic governor hydraulic actuator (EG-R). Downward movement of the relay piston causes the control valves to open with upward movement driving the control valves closed. This review determined that the correct exposure period encompassed the period of time from the last shutdown of the system on June 23, 2016 during surveillance testing. In other words, based on the hydraulic component response on July 3, 2016, the hydraulic system could not have reasonably returned to its normal post shutdown condition from the previous June 23, 2016, testing. This is based on the subsequent start on July 3, where the control valves should have opened to a 20-40% position based on the design of the system hydraulics. Instead, they were driven to a more closed position, indicating that the EG-R and/or remote servo had never repositioned to its proper state from the last shutdown of the system. This would result in the previous assumption of T/2 being invalid. Consistent with Section 2.3 of the Risk Assessment Standardization Project (RASP) Handbook Volume 1 – Internal Events, based on this review, the failure is assumed to have occurred when the component was last operated/shutdown and an exposure of 'T plus repair' is the appropriate assumption. Therefore, given the system response, the exposure time would be 44 days, plus 5 days of repair time. The 5 days of repair time should not include an assumption that RCIC would be in 'Test and Maintenance,' given that it would be expected to be protected. The risk evaluation at the end of this enclosure removed the RCIC basic event in 'Test and Maintenance' for the 5 days of repair.

Additional Observations of PSEG Model Revisions

The NRC staff noted that in a previous risk assessment provided by PSEG prior to the inspection report issuance, the internal event risk assessment dominant contributors due to the finding were: Loss of Condenser Vacuum scenario, 21%; and Medium Break Loss-of-coolant-accident (MBLOCA) scenario, 20%. PSEG's letter dated December 14, 2016, described a number of Fault Tree Changes, but did not highlight a significant change to Figure A.7-2 within HC-ASM-003 that credited the secondary-side condensate pumps for MBLOCA events. This change essentially rendered the conditional effect of the HPCI failure insignificant for MBLOCA events as compared to the original model. The NRC staff determined this to be a change from the existing PSEG assumptions within PRA notebook HC PRA-005.05, "Main Condenser, Condensate and Feedwater Systems." Specifically, the system success criteria had stated that failure to supply sufficient flow for level control occurs if instrument air is unavailable. Additionally, any scenario that leads to high containment pressure of >1.68 psig will result in loss of Turbine Area Cooling System (TACS) cooling to the secondary condensate pumps, and operators will not recover this cooling capability. Hence, under such scenarios the secondary condensate pumps would not be expected to remain available.

The NRC staff had a number of concerns whether the revision to the internal event risk assessment properly considered the secondary plant response during a MBLOCA event, and discussed these concerns during the December 21, 2016, telephone call with PSEG. PSEG provided a subsequent response, dated January 3, 2017, and stated that the calculation in HC-ASM-003, contained potentially non-conservative modeling approaches and should be reviewed before it is incorporated into an updated PRA model of record. More specifically, it was found that the model had not taken into account possible failures of the secondary condensate pumps (SCPs) due to isolation of their normal cooling supply to the pump and 7.2 kV and 4.16 kV motor bearings. Additionally, the NRC staff noted that PSEG stated they had not included the possibility that the Main Steam Isolation Valves (MSIVs) could close due to low reactor vessel pressure, or, more significantly from a risk perspective, drift closed due to loss of instrument air pressure. The NRC staff agrees that further analyses would be necessary before incorporating these changes into the permanent Hope Creek risk model for use in other risk applications such as Maintenance Rule 10 CFR 50.65(a)(4) evaluations, or to support future licensing actions.

The details related to the uncertainties associated with fault tree changes within HC-ASM-003 are outside the scope of this assessment but include items such as: potentially non-conservative assumptions used to calculate the amount of time that the secondary condensate pump (SCP) would remain available without cooling, including time-to-alarm conditions; insufficient detail related to the operator and plant response to the expected loss of instrument air during this event, a condition that would cause the 12-inch minimum flow valves for the SCPs to fail open, diverting flow to the condenser rather than to the reactor; timing and impact of the closure of the outboard MSIVs following the loss of instrument air; and insufficient information provided regarding the electrical start response of the SCP motors during this event given unanticipated valve movements (i.e., minimum flow valves potentially open). The above highlights a few of the NRC staff concerns regarding the fault tree change, as well as the additional uncertainty associated with break sizes and the timing of required actions for the spectrum of break sizes. Based on the above, the NRC determined that PSEG did not provide a sufficient justification to revise the SPAR model for MBLOCA events for this evaluation.

Notwithstanding the above, the NRC SDP performed for this issue is not dominated by MBLOCA scenarios, and indirectly gives some amount of credit for possible flow from the secondary side based on a lower failure to depressurize probability assigned in the MBLOCA scenarios. The NRC staff used a basic event for these scenarios of 2.75E-3 consistent with the previous detailed risk evaluation (Sensitivity 5) and SPAR-H method. This failure probability is an order of magnitude smaller than what PSEG uses for failure to depressurize in many of their MBLOCA scenarios (2.2E-2). Thus, the core damage sequences are reduced in the NRC SPAR model and indirectly are comparable to crediting some degree of success for the secondary side. The failure to depressurize probability for small break loss-of-coolant-accidents using SPAR-H was calculated to be 1E-3 (somewhat lower but close to PSEG's value).

The SDP conditional risk evaluation used all of the assessed justified changes mentioned in this enclosure in the following final sensitivity risk evaluation run:

<u>Best Estimate of Conditional Risk Increase from HPCI failure SPAR model</u>
Base-Case 4.43E-6/yr
Conditional-Case (HPCI) failed 1.29E-5/yr
9.19E-7 (44 days) + 7.63E-8 (5 day repair) + External Fire (1.16E-7/yr simplified) = 1.11E-6/yr (White)
The dominant risk sequences were: Loss of condenser heat sink (LOCHS), failure to depressurize with revised lower RCIC failure to run; (LOCHS), failure to depressurize with RCIC in test and maintenance; SBLOCA, failure to depressurize; (LOCHS), failure to depressurize

with failure of RCIC to start; Loss of feedwater, failure to depressurize, with revised failure of RCIC to run. Although this risk is somewhat lower than the preliminary value described in NRC Inspection Report No. 05000354/2016003 (2E-6/yr), it still represents a finding of low-to-moderate risk significance (i.e., White). If the NRC were to determine the above using PSEG's failure to depressurize estimate of 2.2E-2 for MBLOCA scenarios, the overall risk would be somewhat higher.

SUMMARY

In summary, the NRC staff carefully reviewed the responses provided by PSEG. The NRC acknowledges and considered PSEG's viewpoint, but ultimately determined that the new information did not alter our original risk assessment outcome or methodology as described in Inspection Report 05000354/2016003. Based upon the additional information provided, the NRC staff concluded that the finding remains appropriately characterized as White.

Enclosure 2
NOTICE OF VIOLATION

PSEG Nuclear, LLC
Hope Creek Generating Station

Docket No. 50-354
License No. NPF-57
EA-16-184

During an NRC inspection conducted from July 1, 2016 through September 30, 2016, and for which an inspection exit meeting was conducted on October 27, 2016, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

PSEG Nuclear, LLC (PSEG) procedure OP-AA-108-111, "Adverse Condition Monitoring and Contingency Planning," describes the process for creating a formal plan to monitor significant plant conditions and parameters outside of normal operating bands that have not yet reached plant operating procedure action levels. Section 3.3.2 requires that PSEG Operations Shift Management review the current levels and trends of parameters associated with the components being monitored under the Adverse Condition Monitoring (ACM) process to ensure all required actions are being met, and identify any adverse trends before they reach ACM threshold values for action.

PSEG established Adverse Condition Monitoring and Contingency Plan HC 15-008 in response to the identification, in 2015, of steam leak-by through the HPCI steam admission valve (FD-F001). The ACM required PSEG staff to perform monthly HPCI turbine oil sampling and analysis for water contamination and, upon identification of a specified amount of contamination, to inspect and flush the turbine oil system.

Hope Creek Technical Specification 3.5.1.c requires that if the High Pressure Coolant Injection (HPCI) system becomes inoperable during power operation, the reactor may remain in operation for a period not to exceed 14 days.

Contrary to the above, from May 20, 2015, to August 7, 2016, PSEG did not appropriately accomplish activities affecting quality in accordance with a prescribed instruction. Specifically, PSEG did not review the current levels and trends of HPCI parameters being monitored under the ACM process to ensure all required actions were being met, and to identify any adverse trends before they reached ACM threshold values for action. In particular, PSEG did not perform monthly HPCI turbine oil sampling and analysis for water contamination. As a result, PSEG did not identify moisture contamination in the HPCI turbine oil system, and did not take the necessary response actions. Consequently, moisture intrusion degraded the hydraulic actuator such that, on July 3 and August 7, 2016, during HPCI valve functional testing, the HPCI governor control valve (FV-4879) failed to stroke open as required. As a consequence of this failure, PSEG also violated TS 3.5.1.c because based on analysis of the HPCI governor control valve and hydraulic actuator failures, the NRC determined that the HPCI system was inoperable for a period greater than its technical specification allowed outage time of 14 days.

This violation is associated with a White Significance Determination Process finding.

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence, and the date when full compliance was achieved is already adequately addressed on the docket in NRC Inspection Report Number 05000354/2016003, in your letters dated December 14, 2016, and January 3, 2017, and in the summary of the December 21, 2016, telephone call. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation; EA-16-184," and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region I, 2100 Renaissance Boulevard, Suite 100, King of Prussia, PA 19406, and a copy to the NRC Resident Inspector at Hope Creek Generating Station, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

If you choose to respond, your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. Therefore, to the extent possible, the response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

In accordance with 10 CFR 19.11, PSEG may be required to post this Notice within two working days of receipt.

Dated this 6th day of February 2017.