UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 EAST LAMAR BLVD
ARLINGTON, TEXAS 76011-4511

October 2, 2013

Mr. Mark E. Reddemann
Chief Executive Officer
Energy Northwest
P.O. Box 968 (Mail Drop 1023)
Richland, WA 99352-0968

SUBJECT: COLUMBIA GENERATING STATION – THE NRC COMPONENT DESIGN BASES INSPECTION REPORT 05000397/2013007

Dear Mr. Reddemann:

On August 22, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Columbia Generating Station. The enclosed inspection report documents the inspection results which were discussed on August 22, 2013, with B. MacKissock, Plant Manager, and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

The attached inspection report documents seven NRC identified findings of very low safety significance (Green). All of the findings were determined to involve violations of the NRC requirements. Additionally, the report documents one Severity Level IV violation with no associated finding. The NRC is treating these violations as non-cited violations (NCV's) consistent with Section 2.3.2a of the Enforcement Policy.

If you contest these non-cited violations or significance of these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Columbia Generating Station. The information you provide will be considered in accordance with the NRC Inspection Manual Chapter 0305.

If you disagree with the characterization of the crosscutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at the Columbia Generating Station.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS).

ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Thomas R. Farnholtz, Branch Chief
Engineering Branch 1
Division of Reactor Safety

Dockets No.: 50-397
License No.: NPF-21

Enclosure: Inspection Report 05000397/2013007
w/ Attachment 1: Supplemental Information
Attachment 2: Detailed Risk Evaluations for the Columbia Generating Station Component Design Bases Inspection

cc w/encl:
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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-397
License:	NPF-21
Report Nos.:	05000397/2013007
Licensee:	Energy Northwest Inc.
Facility:	Columbia Generating Station
Location:	Richland, WA
Dates:	July 29, 2013 through August 22, 2013
Team Leader:	Gerond A. George, Senior Reactor Inspector, Engineering Branch 1
Inspectors:	Jonathan Braisted, Reactor Inspector, Engineering Branch 1 Theresa Buchanan, Operation Engineer, Operations Branch W. Chris Smith, Project Engineer
Accompanying Personnel:	George Replogle, Senior Reactor Analyst, Division of Reactor Safety Maty Yeminy, Contractor, Beckman and Associates Stanley Kobylarz, Contractor, Beckman and Associates Tania Martinez-Navedo, Electrical Engineer, Office of Nuclear Reactor Regulation, Division of Engineering
Approved By:	Thomas R. Farnholtz, Branch Chief, Engineering Branch 1

SUMMARY OF FINDINGS

IR 05000397/2013007; 07/29/2013 – 08/22/2013; Columbia Generating Station; baseline inspection, NRC Inspection Procedure 71111.21, "Component Design Bases Inspection."

The report covers an announced inspection by a team of five regional inspectors and two contractors. Seven findings were identified. All of the findings were of very low safety significance (Green). One Severity Level IV violation was identified. The final significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after the NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings

Cornerstone: Mitigating Systems

- Green. The team identified a Green non-cited violation of 10 CFR 50.63, "Loss of All Alternating Current Power," which states, in part, that each light-water-cooled nuclear power plant licensed to operate under this part must be able to withstand for a specified duration and recover from a station blackout as defined in § 50.2. Specifically, from June 8, 2013, to August 6, 2013, the licensee failed to demonstrate the ability to restore alternating current power and recover from a station blackout event when the licensee determined that the station battery voltage would be below the vendor minimum rated voltage to operate the diesel generator output breaker close coil. This violation was entered into the licensee's corrective action program as Action Request 291162. Subsequently, the licensee tested a spare 4160 Vac breaker, similar to the diesel generator output breaker, to provide reasonable assurance that the diesel generator breaker would close after the 4-hour coping period. The test results determined that the breaker would close reliably with less than the manufacturers rated voltage and within the capability of the battery.

  The team determined that the failure to demonstrate the ability to restore emergency alternating current power to recover from a station blackout in accordance with 10 CFR 50.63 was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding represented a reasonable question of functionality of the use of emergency diesel generators to recover from a station blackout. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding was of very low safety significance (Green), because the finding was confirmed to be a qualification deficiency that did not affect the functionality of the emergency diesel generators. The team determined that this finding had a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee failed to implement a corrective action program with a low threshold for identifying issues. [P.1(a)] (Section 1R21.2.1)

- Green. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which states in part, that "design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Specifically, prior to August 22, 2013, the licensee failed to verify by either an analysis or test that the Class 1E inverters would continue to operate reliably when subjected to the effects of electrical faults that could be postulated to occur at non-Class 1E loads, due to a lack of seismic qualification of the loads, during and after a design basis loss-of-offsite power (LOOP) and seismic event. This violation was entered into the corrective actions program as Action Requests 291144 and 291248. Once identified, the licensee performed preliminary short circuit and coordination calculations during the inspection to provide reasonable assurance that the Class 1E fuses in the distribution to the non-Class 1E loads would operate within the first cycle of fault current.

  The team determined that the failure to demonstrate conformance to the independence requirements of IEEE 308-1974 was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding resulted in a condition where there was a reasonable doubt on the operability of the system. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 4, the team determined a detailed risk evaluation was necessary because the finding involved the total loss of safety function that contributed to an external event initiated core damage accident sequence. Therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined, qualitatively, that the change to the core damage frequency would be less than 1E-7 per year (Green). Since the change to the core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. This finding did not have a cross-cutting aspect because the most significant contributor did not reflect current licensee performance. (Section 1R21.2.2)

- Green. The team identified a Green non-cited violation of Technical Specification 5.4.1(a), "Procedures" which requires, "Written procedures shall be established, implemented, and maintained covering the following activities: (a) The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978." From April 4, 1984, to August 7, 2013, the licensee failed to establish procedures for filling and venting the emergency diesel generator fuel oil tanks after potential tornado damage. This violation was entered into the licensee's corrective action program as Action Request 291543. Subsequently, the licensee implemented Night Order 1477 to provide interim procedural guidance to operators prior to developing a formal emergency procedure.

The team determined that failure to establish procedures for filling and venting diesel engine fuel oil storage tanks after tornado damage in accordance with Technical Specification 5.4.1(a) was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the procedures attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 4, the inspectors determined a detailed risk evaluation was necessary because, during an external initiating event, the finding would degrade one or more trains of a system that supports a risk significant system or function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the change in core damage frequency was 1.2E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. This finding had a crosscutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. [P.1(d)] (Section 1R21.2.3)

- <u>Green</u>. The team identified a Severity Level IV non-cited violation of 10 CFR 50.71(e), which states, in part, that each person licensed to operate a nuclear power reactor shall update, periodically, the final safety analysis report originally submitted as part of the application for the license, to assure that the information included in the report contains the latest information. Specifically, from May 2009 to August 22, 2013, the team identified that the diesel engine fuel oil storage tanks cleaning and inspection frequency was not updated in the final safety analysis report to include the latest information developed. This violation was entered into the licensee’s corrective action program as Action Request 292360. The violation did not represent an immediate safety concern.

  The licensee’s failure to update the final safety analysis report to reflect the cleaning and inspection frequency of the diesel engine fuel oil storage tanks in Section 9.5.4.4 “Testing and Inspection Requirements” was a violation of the NRC requirements. The inspectors determined that this violation was also a performance deficiency. However, the inspectors determined that the performance deficiency was minor. The inspectors considered this issue to be within the traditional enforcement process because it had the potential to impact the NRC's ability to perform its regulatory oversight function. The inspectors used the NRC Enforcement Policy to evaluate the significance of this violation. The inspectors determined that the violation was a Severity Level IV because it was similar to an example provided in Section 6.1 of the NRC Enforcement Policy. The inspectors did not assign a cross-cutting aspect to this non-cited violation because there was no finding associated with this traditional enforcement violation. (Section 1R21.2.3)

- <u>Green</u>. The team identified a Green non-cited violation of Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” which states in part, that “design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Specifically, from June 6, 1992, to August 20, 2013, the licensee failed to verify or check the adequacy of the design, by the use of alternate or simplified calculational methods, the technical basis that justified the dispersion of nitrogen in a tornado event to prevent loss of function of the emergency diesel generators. This violation was entered into the licensee's corrective action program as Action Request 292322. The violation did not represent an immediate safety concern.

The team determined that the failure to verify the adequacy of the technical basis that justified the dispersion of nitrogen in a tornado event was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the functionality of the diesel generators was called into question for the failure to provide a technical basis for the effects of nitrogen leakage on the combustion air system. Using the Manual Chapter 0609, Appendix A, Exhibit 4, the inspectors determined a detailed risk evaluation was necessary because, during an external initiating event, the finding would degrade one or more trains of a system that supports a risk significant system or function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the change in core damage frequency was 1.2E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance. (Section 1R21.2.4)

- <u>Green</u>. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which states in part, that "design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program." Specifically, prior to August 22, 2013, the licensee failed to assess the cumulative effects of the 4160 Vac system, test source, and transient harmonics on the secondary level undervoltage relays. This violation was entered into the licensee's corrective action program as Action Requests 291665 and 292405. The violation did not present an immediate safety concern.

  The licensee's failure to analyze the cumulative effect of electrical system, test source, and transient harmonics on the secondary level undervoltage relays was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to analyze the cumulative effect of electrical harmonics on the secondary level undervoltage relays would have the potential to cause the relays to fail to actuate at the setpoints specified in technical specifications. Using the Manual Chapter 0609, Appendix A,

Exhibit 2, the team determined the finding is of very low safety significance (Green), because the finding was confirmed to be a qualification deficiency that did not affect the functionality of the undervoltage relays. This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance. (Section 1R21.2.5)

- Green. The team identified a Green non-cited violation of Technical Specification 5.4.1(b) which states, in part, “Written procedures shall be established, implemented, and maintained covering the following activities: The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33.” Specifically, from 1997 to August 21, 2013, the licensee failed to revise emergency operating procedures for reactor pressure vessel control and primary containment control when it was determined that the required net positive suction head for the emergency core cooling pump were no longer bounded by the pumps vortex limits. This violation was entered into the corrective action program as Action Request 292153. On August 21, 2013, the licensee implemented a night order giving guidance to monitor the pumps for cavitation and take actions to prevent degraded operation until the procedures were revised.

  The team determined that the failure to maintain emergency operating procedures which included appropriate net positive suction head limits in accordance with Technical Specification 5.4.1(b) was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating System cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding was more than minor because the procedures were in a condition that would adversely affect the licensee’s response to an emergency. Using the Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding represented a loss of safety system function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the bounding change to the core damage frequency was less than 1.8E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance. (Section 1R21.2.6)

- Green. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” which states, in part, “Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.” Specifically, from August 16, 2013, to August 21, 2013, the licensee failed to implement a prompt compensatory corrective action to correct an adverse condition in emergency operating procedures that would have led to the loss of emergency core cooling pumps due to inadequate available net positive suction head. This violation was entered into the corrective action program as Action Request 292437. On

August 21, 2013, the licensee implemented a night order giving guidance to monitor the pumps for cavitation and take actions to prevent degraded operation until the procedures are revised.

The team determined that the failure to implement an interim compensatory corrective action to promptly correct an adverse condition in emergency operating procedures in accordance with 10 CFR 50, Appendix B, Criterion XVI was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating System cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding was more than minor because the procedures were in a condition that would adversely affect the licensee's response to an emergency. Using the Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding represented a loss of safety system function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the bounding change to the core damage frequency was less than 1.8E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. The team determined that this finding has a crosscutting aspect in the area of problem identification and resolution, corrective action program, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. [P.1(d)]
(Section 1R21.2.6)

REPORT DETAILS

1 REACTOR SAFETY

This inspection of the component design bases verifies that plant components are maintained within their design and licensing bases. Additionally, this inspection provides monitoring of the capability of the selected components and operator actions to perform their design bases functions. As plants age, modifications may alter or disable important design features making the design bases difficult to determine or obsolete. The plant risk assessment model assumes the capability of safety systems and components to perform their intended safety function successfully. This inspectable area verifies aspects of the Initiating Events, Mitigating Systems and Barrier Integrity cornerstones for which there are no indicators to measure performance.

1R21 Component Design Bases Inspection (71111.21)

To assess the ability of the Columbia Generating Station equipment and operators to perform their required safety functions, the team inspected risk significant components and the licensee's responses to industry operating experience. The team selected risk significant components for review using information contained in the Columbia Generating Station probabilistic risk assessments and the U.S. Nuclear Regulatory Commission's (NRC) standardized plant analysis risk model. In general, the selection process focused on components that had a risk achievement worth factor greater than 1.3 or a risk reduction worth factor greater than 1.005. The items selected included components in both safety-related and nonsafety-related systems. The team selected the risk significant operating experience to be inspected based on its collective past experience.

.1 Inspection Scope

To verify that the selected components would function as required, the team reviewed design basis assumptions, calculations, and procedures. In some instances, the team performed calculations to independently verify the licensee's conclusions. The team also verified that the conditions of the components were consistent with the design basis and that the tested capabilities met the required criteria.

The team reviewed maintenance work records, corrective action documents, and industry operating experience records to verify that licensee personnel considered degraded conditions and their impact on the components. For the review of operator actions, the team observed operators during simulator scenarios, as well as during simulated actions in the plant.

The team performed a margin assessment and detailed review of the selected risk-significant components to verify that the design basis have been correctly implemented and maintained. This design margin assessment considered original design issues, margin reductions because of modifications, and margin reductions identified as a result of material condition issues. Equipment reliability issues were also considered in the selection of components for detailed review. These included items such as failed performance test results; significant corrective actions; repeated maintenance; 10 CFR 50.65(a)1 status; operable, but degraded, conditions; the resident inspector input of problem equipment; system health reports; industry operating experience; and licensee problem equipment lists. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense in-depth margins.

The inspection procedure requires a review of 15 to 25 total samples that include risk-significant and low design margin components, containment related components, and operating experience issues. The sample selection for this inspection was 16 components, 1 containment related component; 4 operating experience items; and 6 event based activities associated with the components. The selected inspection and associated operating experience items supported risk significant functions including the following:

a. Electrical power to mitigation systems: The team selected several components in the electrical power distribution systems to verify operability to supply alternating current (ac) and direct current (dc) power to risk significant and safety-related loads in support of safety system operation in response to initiating events such as loss of offsite power, station blackout, and a loss-of-coolant accident with offsite power available. The team selected the following components:

    - Division 1 Emergency Diesel Generator, DG-GEN-DG1
    - Critical Inverter, EN-IN-2A
    - 4160 Vac Class 1E Switchgear, SM-8
    - 4160/480 Vac Transformer, E-TR-8/83
    - 4160 Vac Circuit Breaker, E-CB-8/83

b. Components necessary to mitigate radiation releases: The team reviewed components required to perform isolation functions to prevent an unmonitored release of radiation. The team selected the following components:

    - Containment Electrical Penetration, PEN-RLK-17-7A

c. Mitigating systems needed to attain safe shutdown: The team reviewed components and support systems required to perform the safe shutdown of the plant. The team selected the following components:

    - Emergency Diesel Generator Fuel Oil Storage Tanks, DO-TK-1A , DO-TK-1B, and DO-TK-2
    - Diesel Engine Combustion Air Intake and Building Ventilation, DG-1C
    - Residual Heat Removal Pump, RHR-P-2A
    - Residual Heat Removal Valve, RHR-V-24A

- Residual Heat Removal Valve, RHR-V-48B
- High Pressure Core Injection Valve Motor, HPCS-V-4
- Reactor Core Isolation Cooling Pump, RCIC-P-1
- Reactor Core Isolation Cooling Pump Low Suction Pressure Switch, RCIC-PS-1
- Low Pressure Core Spray Pump, LPCS-P-1
- Residual Heat Removal System Pipe Support, RHR-84

.2 Results of Detailed Reviews for Components:

.2.1 Division 1 Emergency Diesel Generator, DG-GEN-DG1

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the division 1 emergency diesel generator, DG-GEN-DG1. The team also performed walkdowns, and conducted interviews with system and design engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically the team reviewed:

- Schematics for the emergency diesel start circuits and trip circuits.
- Schematics of the generator field flash and breaker close circuits and trip circuits.
- Vendor nameplate data and specifications for the generator.
- Calculations for determining diesel generator load under design/licensing basis conditions.
- Calculations and supporting documentation for determining brake horsepower loads for the major pumps loaded on the diesel generator under design/licensing basis conditions.
- Calculations and supporting documentation for determining minimum voltage at generator field flash relays, starting air solenoids, generator breaker trip coils, and generator breaker close coils under design/licensing basis conditions.
- Completion of last preventive maintenance work orders for the generator field flash, diesel starting air solenoids, and diesel generator breaker close coils and trip coils.

b. Findings

1. Failure to Support the Ability to Restore Class 1E Diesel Generator Standby Power and Recover from Station Blackout (SBO) Conditions

Introduction. The team identified a Green non-cited violation of 10 CFR 50.63, “Loss of All Alternating Current Power,” for the licensee’s failure to demonstrate the ability to withstand and recover from a station blackout. Specifically, the licensee failed to demonstrate the ability to restore Class 1E emergency diesel generator alternating current power and recover from station blackout conditions.

Description. The team reviewed Calculation 2.05.01, “125V (Div 1) Control Circuit Evaluation,” Revision 11, dated June 8, 2013. This calculation concluded that the battery voltage available after two hours into a station blackout event did not satisfy the vendor minimum voltage requirement for the division 1 emergency diesel generator output circuit breaker close coil. An evaluation for the division 2 emergency diesel generator output circuit breaker close coil contained the same conclusion. The licensee justified that the lack of sufficient voltage to close the diesel generator output circuit breakers on both emergency diesel generators was not an adverse condition because the licensee assumed offsite power would be available at four hours after a station blackout. This adverse condition was not entered into the licensee’s corrective action program.

As described in Appendix 8A of the Columbia Generating Station Updated Final Safety Analysis Report, the licensee committed to NUMARC 8700 as the standard for addressing station blackout. NUMARC 8700, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors,” recommends that the licensee should implement procedures that are necessary to restore offsite alternating current power or standby, Class 1E alternating current power sources (emergency diesel generators). The station blackout event is assumed to end once alternating current power is restored. It further assumes “a single path to achieve and maintain safe shutdown conditions in a station blackout. This consists of repeated attempts at restoring ac power to a shutdown bus while performing operations designed to stabilize the plant using available equipment.”

Based on the conclusions of the calculations and NUMARC 8700 guidelines, the team determined that insufficient voltage at the division 1 and 2 emergency diesel generator output breaker close coils would significantly degrade the ability of the licensee to restore emergency alternating current power between two and four hours into the coping period of a station blackout.

After the team identified the issue, the licensee entered the issue in the corrective action program as Action Request 291162. Subsequently, the licensee tested a spare 4160 Vac circuit breaker, similar to the diesel generator output breaker, to provide reasonable assurance that the diesel generator breaker would close after the 4-hour coping period. The test results determined that the breaker would close reliability with less than the manufacturers rated voltage and within the capability of the battery.

Analysis. The team determined that the failure to demonstrate the ability to restore emergency alternating current power to recover from a station blackout in accordance with 10 CFR 50.63 was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding represented a reasonable question of functionality of the use of emergency diesel generators to recover from a station blackout. Using the Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding was of very low safety significance (Green), because the finding was confirmed to be a qualification deficiency that did not affect the functionality of the emergency diesel generators. The team determined that this finding had a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee failed to implement a corrective action program with a low threshold for identifying issues. Specifically, the licensee failed to implement a corrective action program with a low threshold when the licensee determined, on June 8, 2013, that the station battery voltage would be below the vendor minimum rated voltage to close the diesel generator output breaker. [P.1(a)]

Enforcement. The team identified a Green non-cited violation of 10 CFR 50.63, "Loss of All Alternating Current Power," which states, in part, that each light-water-cooled nuclear power plant licensed to operate under this part must be able to withstand for a specified duration and recover from a station blackout as defined in § 50.2. Contrary to this requirement above, the licensee failed to demonstrate that the Columbia Generating Station was able to withstand for a specified duration and recover from a station blackout. Specifically, from June 8, 2013, to August 6, 2013, the licensee failed to demonstrate the ability to restore alternating current power and recover from a station blackout event when the licensee determined that the station battery voltage would be below the vendor minimum rated voltage to operate the diesel generator output breaker close coil. This finding was entered into the licensee's corrective action program as Action Request 291162. Subsequently, the licensee tested a spare 4160 Vac breaker, similar to the diesel generator output breaker, to provide reasonable assurance that the diesel generator breaker would close after the 4-hour coping period. The test results determined that the breaker would close reliability with less than the manufacturers rated voltage and within the capability of the battery. Because this finding was of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2 of the NRC Enforcement Policy. (NCV 05000397/2013007-01; Failure to Support the Ability to Restore Class 1E Diesel Generator Standby Power and Recover from Station Blackout (SBO) Conditions)

.2.2 Critical Inverter, E-IN-2A

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with critical safety-related inverter E-IN-2A and uninterruptible power supply power panel E-PP-8AA. The team also performed walkdowns and conducted interviews with system and design engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Preliminary short circuit calculations, inverter sizing calculations, preliminary coordination studies, and voltage drop calculations.
- One-line diagrams and design basis documents for the inverter electrical distribution system to identify requirements and interfaces.
- Preventive maintenance activities to verify the inverter system maintained according to manufacturer recommendations.
- Separation and independence standards criteria to ensure the inverter system was designed to provide the required independence between Class 1E and non-Class 1E loads.
- Past modifications associated with the inverter.

b. Findings

1. Failure to Demonstrate Compliance with IEEE 308-1974 for Independence of Divisions 1 and 2 Vital Instrumentation and Control Power Systems

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the failure to verify and check the adequacy of design to demonstrate compliance with IEEE 308-1974 for the required independence of divisions 1 and 2 120/240-Volt Class 1E instrumentation and control power system inverters.

Description. The team requested the short circuit calculation and coordination study to verify that the critical Class 1E inverters were capable of providing sufficient current to interrupt circuit faults that could occur in non-Class 1E distribution circuits on the inverter power system, as specified in the Columbia Generating Station Updated Final Safety Analysis Report, Chapter 8, "Electric Power."

The team identified that the licensee failed to perform an analysis or test to demonstrate conformance with IEEE 308-1974, for the required independence of the critical inverter systems, when the Class 1E inverters were replaced in 2001. Specifically, the licensee failed to perform an analysis or test that demonstrated that the Class 1E inverters would continue to operate reliably when subjected to the effects of electrical faults that could be postulated to occur at non-Class 1E loads. As stated in Chapter 8, these postulated electrical faults could be cause by mechanical, structural, or electrical failures in the non-Class 1E raceway or equipment during seismic or other degrading events, e.g., missiles.

Once identified, the licensee performed preliminary short circuit and coordination calculations during the inspection to provide reasonable assurance that the Class 1E fuses connected to the non-Class 1E loads would operate within the first cycle of fault current, which was within the manufacturer's rated capability of the inverter.

Analysis. The team determined that the failure to demonstrate conformance to the independence requirements of IEEE 308-1974, was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding resulted in a condition where there was a reasonable doubt on the operability of the system. Using the Manual Chapter 0609, Appendix A, Exhibit 4, the team determined a detailed risk evaluation was necessary because the finding involved the total loss of safety function that contributes to an external event initiated core damage accident sequence; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined, qualitatively, that the change to the core damage frequency would be less than 1E-7 per year (Green). Since the change to the core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. (See Attachment 2 for analysis results.) This finding did not have a cross-cutting aspect because the most significant contributor did not reflect current licensee performance.

Enforcement. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which states in part, that "design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Contrary to this requirement, the licensee failed to provide for verifying or checking the adequacy of the design of divisions 1 and 2, 120/240-Volt Class 1E instrumentation and control power systems inverters by the performance of design reviews or performance of a suitable testing program. Specifically, prior to August 22, 2013, the licensee failed to verify by either an analysis or test that the Class 1E inverters would continue to operate reliably when subjected to the effects of electrical faults that could be postulated to occur at non-Class 1E loads, due to a lack of seismic qualification of the loads, during and after a design basis loss-of-offsite power (LOOP) and seismic event. This condition was entered into the corrective actions program as Action Requests 291144 and 291248. Once identified, the licensee performed preliminary short circuit and coordination calculations during the inspection to provide reasonable assurance that the Class 1E fuses in the distribution to the non-Class 1E loads would operate within the first cycle of fault current. Because this finding was of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2 of the NRC Enforcement Policy. (NCV 05000397/2013007-02; Failure to Demonstrate Independence Requirements of IEEE 308-1974 for Divisions 1 and 2 Vital Instrumentation and Control Power Systems)

.2.3 Emergency Diesel Generator Fuel Oil Storage Tanks, DO-TK-1A , DO-TK-1B, and DO-TK-2

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, procedures, and condition reports associated with the emergency diesel generator fuel oil storage tanks DO-TK-1A, DO-TK-1B, and DO-TK-2. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history, work history, and corrective action program reports.
- Procedures for preventive maintenance, inspection, calibration, and surveillance testing.
- Compliance with Regulatory Guide 1.137.
- Modifications to install overflow lines from day tank to storage tanks.

b. Findings

1. Failure to Establish Emergency Procedures for Filling and Venting Diesel Fuel Oil Tanks after Tornado Damage

Introduction. The team identified a Green non-cited violation of Technical Specification 5.4.1(a), "Procedures" for failure to establish, implement, and maintain a procedure recommended in Regulatory Guide 1.33, Revision 2, Appendix A, Section 6.w. Specifically, the licensee failed to provide procedures for filling and venting the emergency diesel generator fuel oil tanks after potential tornado damage.

Description. The team reviewed the design basis documents for the diesel generator fuel oil storage tanks and associated fill and vent piping. The regular fill and vent lines for the diesel fuel oil system are not protected from tornado and associated missiles. Typically the safety-related emergency diesel generator fuel oil storage tank fill and vent lines are tornado-missile protected to conform with 10 CFR Part 50 Appendix A, Criterion 2, "Design bases for protection against natural phenomena." However during the original licensing of the plant, the licensee stated that there are additional connections which can be used as fill and vent openings; therefore, the regular fill and vent lines do not need to be protected from natural phenomenon.

Section 9.5.4.2 of the FSAR states "In the event of fill line damage due to a missile the pump-out connection (which is protected by a metal enclosure located at ground level) may be used for the fuel oil filling operation." The team reviewed procedures applicable for this scenario, and found that emergency procedure ABN-WIND had no specific actions to accomplish the filling and venting of the diesel engine fuel oil storage tank.

Analysis. The team determined that failure to establish procedures for filling and venting diesel engine fuel oil storage tanks after tornado damage in accordance with Technical Specification 5.4.1(a) was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the procedures attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Manual Chapter 0609, Appendix A, Exhibit 4, the inspectors determined a detailed risk evaluation was necessary because, during an external initiating event, the finding would degrade one or more trains of a system that supports a risk significant system or function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the change in core damage frequency was 1.2E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. (See Attachment 2 for analysis results.) This finding had a crosscutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. Specifically, the licensee performed an audit, prior to this inspection, and identified that the fill and vent lines for the diesel fuel oil storage tank were not protected from tornado missiles, but did not confirm any procedures were in place. [P.1(d)]

Enforcement. The team identified a Green non-cited violation of Technical Specification 5.4.1(a), "Procedures" which requires, "Written procedures shall be established, implemented, and maintained covering the following activities: (a) The applicable procedures recommended in Regulatory Guide 1.22, Revision 2, Appendix A, February 1978. Contrary to this requirement, the licensee did not did not establish, implement, or maintain procedures as recommended by Regulatory Guide 1.33, Appendix A, Section 6.w. Specifically, from April 4, 1984, to August 7, 2013, the licensee failed to establish procedures for filling and venting the emergency diesel generator fuel oil tanks after potential tornado damage. The condition was entered into the licensee's corrective action program as Action Request 291543. Subsequently, the licensee implemented Night Order 1477, to provide interim procedural guidance to operators prior to developing a formal emergency procedure. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2, of the NRC Enforcement Policy. (NCV 05000397/2013007-03; Failure to Establish Emergency Procedures for Filling and Venting Diesel Fuel Oil Tanks after Tornado Damage)

2. Failure to Update the FSAR for the Cleaning and Inspection Frequency of the Diesel Fuel Oil Storage Tanks

Introduction. The inspectors identified a Severity Level IV non-cited violation for the licensee's failure to update the final safety analysis report in accordance with 10 CFR 50.71(e) to include a description of the inspection frequency for the safety-related diesel fuel oil storage tanks in Section 9.5.4.4.

Description. The inspectors reviewed the final safety analysis report to verify the testing and inspection requirements for the diesel engine fuel oil storage tanks. The inspectors identified that Section 9.5.4.4 "Testing and Inspection Requirements," listed the cleaning frequency for the diesel engine fuel oil storage tanks as every 12 years. The licensee is committed to Regulatory Guide 1.137 "Fuel Oil Systems for Standby Diesel Generators" and Section C.2.f. states "As a minimum, the fuel oil stored in the supply tanks should be removed, the accumulated sediment removed, and the tanks cleaned at 10-year intervals." The inspectors found that in July, 2000, the licensee issued Licensing Document Change Notice Form LDCN-FSAR-00-41 to change the inspection interval to every 12 years for budget constraints.

In May 2009, the licensee generated Action Request 196395 to update the program procedure MOT-DIESEL-1-1 for the diesel fuel oil storage tank inspection frequency from 10 years to 12 years, to align with the specific preventative maintenance procedure MMP-DO-E001. In February 2011, the licensee issued Action Request 234519, to change the inspection interval back to 10 years to align with the commitments however the final safety analysis report was not updated to reflect the correct cleaning frequency of 10 years specified by Regulatory Guide 1.137.

Analysis. The licensee's failure to update the final safety analysis report to reflect the cleaning and inspection frequency of the diesel engine fuel oil storage tanks in Section 9.5.4.4, "Testing and Inspection Requirements" was a violation of the requirements. The inspectors determined that this violation was also a performance deficiency. However, the inspectors determined that the performance deficiency was minor. The inspectors considered this issue to be within the traditional enforcement process because it had the potential to impact the NRC's ability to perform its regulatory oversight function. The inspectors used the NRC Enforcement Policy to evaluate the significance of this violation. The inspectors determined that the violation was a Severity Level IV because it was similar to an example provided in Section 6.1 of the NRC Enforcement Policy. The inspectors did not assign a cross-cutting aspect to this non-cited violation because there was no finding associated with this traditional enforcement violation.

Enforcement. The team identified a Severity Level IV non-cited violation of 10 CFR 50.71(e), which states, in part, that each person licensed to operate a nuclear power reactor shall update, periodically, the final safety analysis report originally submitted as part of the application for the license, to assure that the information included in the report contains the latest information developed. Contrary to this requirement, the licensee failed to update, periodically, the final safety analysis report originally submitted as part of the application for the license, to assure that the information included in the report contains the latest information developed. Specifically, from May 2009 to August 22, 2013, the inspectors identified that the diesel engine fuel oil storage tanks cleaning and inspection frequency was not updated in the final safety analysis report to include the latest information developed. This violation was entered into the licensee's corrective action program as Action Request 292360. Because this violation was a Severity Level IV violation and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2, of the NRC Enforcement Policy. (NCV

05000397/2013007-04; Failure to Update the FSAR for the Cleaning and Inspection Frequency of the Diesel Fuel Oil Storage Tanks)

.2.4 Diesel Engine Combustion Air Intake and Building Ventilation, DG-1C

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the diesel engine combustion air intake and building ventilation, DG-1C. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history and corrective action program reports.
- Procedures for preventive maintenance, inspection, and testing.
- Structural calculations for the nitrogen storage tank and associated equipment
- Nitrogen tank foundation and anchorage calculations.
- Emergency diesel generator monthly test and assessed the adequacy of increase in differential pressure across combustion and ventilation air filters.
- The validity of the maximum allowable temperature with respect to temperature sensitive safety related components located in the EDG room.

b. Findings

1. Failure to Provide Technical Basis for Assuming Turbulent Mixing of Diesel Combustion Air

Introduction. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control” for the licensee’s failure to verify or check the adequacy of the design basis for assuming that a failure of a nonsafety-related liquid nitrogen tank would not affect the diesel generator combustion air. Specifically, the licensee incorrectly assumed that, if the nitrogen tank were to fail from a tornado missile, there would be sufficient turbulent mixing of the air from tornado winds to preclude unacceptable levels of nitrogen in the combustion air supply for the emergency diesel generators.

Description. The Columbia Generating Station has a nonsafety-related liquid nitrogen tank located outside of the diesel generator building that is in close proximity to the air intakes for the emergency diesel generators. The team reviewed final safety analysis report statements in Section 3.3.2.4, that stated, “due to the turbulent mixing produced in close proximity to a tornado, no oxygen deficiency condition could sustained outdoors at the diesel generator intake structures.” The team requested the analysis to justify that position. The team noted that the nitrogen tank is not protected from tornado missiles and reviewed a calculation that determined the nitrogen tank would affect the diesel combustion air for a period of up to 8 minutes in calm weather as the nitrogen content of the tank is drained. The team was concerned that the wind may not be favorable for dispersing nitrogen and wind may not be present for the full 8 minute duration required to empty the tank (i.e. the winds may calm after the passing storm).

Based on the team's question, the licensee wrote Action Request 292253, to evaluate the teams concerns. The licensee commissioned a calculation to determine if the turbulent mixing would preclude an oxygen deficiency. However, the preliminary results of the calculation indicated that all three diesel generators could be stalled for approximately one minute regardless of wind speed and that there was not a dramatic improvement of nitrogen dispersion with wind speed.

Analysis. The team determined that the failure to verify the adequacy of the technical basis that justified the dispersion of nitrogen in a tornado event was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to verify the adequacy of the technical basis of the effects of nitrogen leaking from its tank would have the potential to question the functionality of the diesel generators during a tornado event. Using the Manual Chapter 0609, Appendix A, Exhibit 4, the inspectors determined a detailed risk evaluation was necessary because, during an external initiating event, the finding would degrade one or more trains of a system that supports a risk significant system or function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the change in core damage frequency was 1.2E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. (See Attachment 2 for analysis results.) This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance.

Enforcement. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which states in part, that "design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Contrary to this requirement, the licensee failed to provide for verifying or checking the adequacy of the by the use of alternate or simplified calculational methods. Specifically, from June 6, 1992, to August 20, 2013, the licensee failed to for verify or check the adequacy of the design by the use of alternate or simplified calculational methods the technical basis that justified the dispersion of nitrogen in a tornado event to prevent loss of function of the emergency diesel generators. This violation was entered into the licensee's corrective action program as Action Request 292322. The violation did not represent an immediate safety concern. Because this finding was of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2, of the

NRC Enforcement Policy. (NCV 05000397/2013007-05; Failure to Provide Technical Basis for Assuming Turbulent Mixing of Diesel Combustion Air)

.2.5 4160 Vac Class 1E Switchgear, SM-8

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the safety-related 4160 Vac Class 1E switchgear, SM-8. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Calculations for electrical distribution system load flow/voltage drop, short-circuit, and electrical protection and coordination
- Protective device settings and circuit breaker ratings to confirm adequate selective protection and coordination of connected equipment during worst-case short circuit conditions
- Circuit breaker preventive maintenance, inspection, and testing procedures to confirm inclusion of relative industry operating experience and vendor recommendations
- Results of completed preventive maintenance on 4160 Vac switchgear
- Degraded voltage protection scheme and circuit breaker control logics that initiate automatic bus transfers
- NRC Information Notice 95-05, “Undervoltage Protection Relay Settings Out of Tolerance Due To Test Equipment Harmonics”

b. Findings

1. Failure to Analyze the Effect of System, Test Source, and Transient Harmonics on Proper Operation of Undervoltage Relays

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” for the licensee’s failure to analyze the cumulative effect of system, test source, and transient harmonics on the degraded voltage relays.

Description. 4160 Vac switchgear bus, SM-8, is equipped with primary and secondary undervoltage relays. The primary undervoltage relays are high speed, instantaneous undervoltage relays that are utilized for detection of undervoltage at the switchgear buses. The secondary level undervoltage relays are static undervoltage relays with definite time delay that are utilized for detection of sustained degraded voltage in the offsite power system. The secondary level undervoltage relays are part of a protection scheme designed to complement the primary undervoltage relays by ensuring engineered safety feature motors fed from critical 480 Vac, and 4160 Vac, buses do not operate continuously when connected to a degraded voltage source exceeding the motor (NEMA MG-1) design tolerance of ±10 percent of nameplate.

The team requested the vendor manual for these relays, and the licensee’s response to Information Notice (IN) 95-05. The vendor manual for the Model ITE-27N undervoltage relay, BBC Instruction Bulletin 7.4.1.7-7, states that harmonic distortion in the ac waveform can have a noticeable effect on the relay operating point and on measuring instruments used to calibrate the relay. The bulletin also notes that the relay is available with an internal harmonic filter for applications where waveform distortion is a factor. The licensee’s response to Information Notice 95-05, states that a power system harmonic study was performed in 2001, to assess system harmonics, and that the voltage test sources acquired, as recommended by the relay manufacturer, were bought with a low harmonic distortion content. However, various times since 2001, the licensee stated that there have been changes in the equipment connected to the system. Therefore, the team determined that the study’s conclusion was invalid as to the state of the current system. The team was concerned that persistent harmonics on the 4160 Vac systems could cause the relays to fail to actuate at the setpoint specified in technical specifications.

Persistent harmonics can be produced by the electrical system (internal or external to the site), test sources, and transient operation of equipment. Typical internal sources of system harmonics at nuclear power plants are non-linear loads, and defects in rotating equipment that are not detectable without special instrumentation. The voltage test source used to calibrate the relays can inject harmonics into the relay resulting in an undesired calibration shift, and inaccurate setpoints. Transient harmonics could cause the relays to spuriously reset, in the presence of an actual degraded voltage event thereby delaying the protective function beyond the time delays stipulated in the design bases. Transient harmonics can be produced by circuit breaker switching operations inside the plant or originating from the grid. The inspectors noted that typical industry specifications for allowable power system harmonics (e.g., IEEE 141-1993, Table 9-6) considerably exceed the 0.3% total harmonic distortion specified for test sources in IB 7.4.1.7-7.

Neither Calculation 2.12.58, “Second Level Undervoltage Relay Settings for SM-4, SM-7, and SM-8,” nor Calculation E/I-02-87-07, “Load Flow & Voltage Analysis for the Plant Main Buses AC Distribution Systems,” included considerations pertaining to system and transient harmonic distortion. In Action Request 291665, the licensee confirmed that the ITE 27N undervoltage relays did not have harmonic filters. The inspectors determined that the licensee did not analyze the cumulative effect of the three possible sources of harmonics that could affect the relay setpoints: system harmonics, test source harmonics, and transient harmonics (resulting from motor loads starting, breaker switching, etc.). Therefore, the licensee was unable to identify and mitigate any event where the relay setpoints were offset. In addition, during a degraded voltage condition, concurrent with an accident, could potentially delay the transfer of Class 1E buses to a reliable source of power beyond the required time.

In response to the inspectors' inquiries, the licensee provided Action Request 292405, which states that the licensee needs to perform an additional review of Information Notice 95-05, including the assessment of the need for harmonic filters for the undervoltage relays, the evaluation of the impact of the upgrades to the electrical distribution system of the plant to the system harmonics, the determination on whether routine harmonic distortion measurements should be taken, and the review of degraded voltage relay testing and calibration procedures to minimize harmonic distortion.

The team noted that for this issue to present an operability concern an actual degraded voltage condition would need to exist. The team further noted that per the licensee's response to Generic Letter 2006-02, the licensee has established Letter Agreement 04TX-11739, which establishes communication protocols such that the Columbia Generating Station safety system maintenance and testing activities are coordinated with grid maintenance (e.g., grid switching operations) and testing activities. The Columbia Generating Station operators are provided early warning from Bonneville Power Administration on switching actions or planned outages, and if the voltage drops below a specified level an alarm will be generated at the Munro Control Center. The grid state estimator along with the online contingency analysis run by the Pacific Northwest Security Coordinator will also generate an alarm if the predicted voltages drop below the alarm levels for the contingencies studied. Based on these considerations, the inspectors concluded that the violation did not represent an immediate safety concern.

<u>Analysis</u>. The licensee's failure to analyze the cumulative effect of electrical system harmonics on the secondary level undervoltage relays was a performance deficiency. The performance deficiency was more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to analyze the cumulative effect of electrical system harmonics on the degraded voltage relays would have the potential to cause the relays to fail to actuate at the setpoints specified in technical specifications. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding is of very low safety significance (Green), because the finding was confirmed to be a qualification deficiency that did not affect the functionality of the undervoltage relays. This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance.

<u>Enforcement</u>. The team identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," states in part, that "design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program." Contrary to this requirement, the licensee's design control measures had failed to check the adequacy of the design of the undervoltage relays. Specifically, prior to August 22, 2013, the licensee failed to assess the cumulative effects of the 4160 Vac system, test source, and transient harmonics on the degraded voltage relays. This violation was entered into the licensee's corrective action program as Action Requests 291665 and 292405. The violation did not represent an immediate safety concern. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program, this violation is being

treated as a non-cited violation consistent with Section 2.3.2, of the NRC Enforcement Policy. (NCV 05000397/2013007-06; Failure to Analyze the Effect of System, Test Source, and Transient Harmonics on Proper Operation of Undervoltage Relays)

.2.6 Residual Heat Removal Pump, RHR-P-2A

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the safety-related residual heat removal pump, RHR-P-2A. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Design and operational requirements with respect to pump flow rate, developed head, achieved system flow rate, and net positive suction head.
- The team verified that minimum flow requirements as described in the NRC Bulletin 88-04, were satisfied to avoid pump damage.
- The adequacy of pump discharge check valve testing, the associated acceptance criteria, and the measures taken to avoid pump damage during emergency operation.
- The adequacy of assumptions, limiting parameters, the pump's protection from the formation of air vortexes, and the adequacy of its suction from the suppression pool.
- The tests and analyses served to validate component operation under accident and transients.
- The adequacy of the pump baseline for inservice testing.

b. Findings

1. Failure to Include ECCS Pump NPSH Limits in the Emergency Operating Procedures

Introduction. The team identified a Green non-cited violation of Technical Specification 5.4.1(b), "Procedures," for failure to establish, implement, and maintain emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1. Specifically, the licensee failed to maintain emergency operating procedures when it determined that the net positive suction head limits for the emergency core cooling pumps were no longer bound by the vortex limits included in the emergency operating procedures.

Description. In 1989, the licensee calculated the net positive suction head limits and the vortex limit for all emergency core cooling system pumps. The calculation showed that in all cases, the vortex limits were at higher elevations of the suppression pool and, therefore, all net positive suction head limits were removed from the emergency operating procedures for reactor pressure vessel control and primary containment control.

The net positive suction head limits were deleted from the emergency operating procedures as a result of the Columbia Generating Station EOP/SAG Technical Document TM-2120, Rev. 7, Item 1.4.1, which states, “The NPSH required (NPSHR) for the Columbia ECCS (including RCIC) pumps is always less than the NPSH available (NPSHA) for these pumps at any pump flow or wetwell temperature condition when suppression pool level is at or above the vortex limits of the respective pumps. Consequently, vortex limits bound the NPSH limits and would always be invoked before NPSH becomes limiting.”

In 1997, the licensee discovered that the required net positive suction head for the high pressure core spray pump was significantly greater than it was in the 1989, net positive suction head limit calculation and a new net positive suction head limit calculation was performed. The result of the new calculation showed that the net positive suction head limit of the high pressure core spray pump was more limiting than its vortex limit by about 8 feet. However, the licensee failed to reintroduce the high pressure core spray net positive suction head limit back into the emergency operating procedures although the statement in Technical Document TM-2120, was no longer valid.

As required, the licensee also calculated the net positive suction head limits with suction strainer design debris loadings. The results of these calculations demonstrated that all emergency core cooling pumps’ net positive suction head limits were more limiting than their vortex limits. The net positive suction head limits for the low pressure core spray, residual heat removal A, and residual heat removal C pumps were more limiting than their vortex limits by about 4 feet. Residual heat removal pump B was more limiting by approximately 6 feet. Similarly, the high pressure core spray pump’s net positive suction head limit with suction strainer design loading was more limiting than its vortex limit by approximately 20 feet.

The team determined that the new calculations of the net positive suction head limits invalidate the Technical Document TM-2120 assertion that all emergency core cooling pumps are all bounded by the pumps’ vortex limits and therefore the NPSH Limits should be removed from the emergency operating procedures.

The Columbia Generating Station engineering personnel showed the inspectors a proprietary emergency procedure guideline training document stating that for the containment spray, as well as the residual heat removal pumps, loaded strainers are to be considered in the determination of the net positive suction head limits. The material added that “alternatively” the loaded strainers’ net positive suction head limits may be in the Technical Support Guidelines.

Following discovery, the issue was entered into the corrective action program as Action Request 292153 to correct the condition. The operators were directed to institute a “compensatory action for when suppression pool level is below normal (low level alarm): Monitor the ECCS pumps and RCIC pump for cavitation.” The inspectors were notified that a night order was issued to alert the operators to the deficiency.

The team determined that by not providing the operators with the emergency core cooling pumps' net positive suction head limits in Emergency Operating Procedure 5.1.1, "RPV Control," and Emergency Operating Procedure 5.2.1, "Primary Containment Control," flowcharts deprives the operators the opportunity to throttle pump flow and avoid damage or loss of pumps when net positive suction head limits are exceeded (ref. Emergency Procedure Guidelines/Severe Accident Guidelines, Appendix B, Step C1-3). It also deprives the operators the opportunity to limit the reduction of primary containment pressure by initiating drywell sprays because reducing primary containment pressure will reduce primary containment overpressure, hence, reducing the available net positive suction head for pumps taking suction from the suppression pool (ref. Emergency Procedure Guidelines/Severe Accident Guidelines, Appendix B, Caution 7).

Analysis. The team determined that the failure to maintain emergency operating procedures which included appropriate net positive suction head limits in accordance with Technical Specification 5.4.1(b) was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating System cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding was more than minor because the procedures were in a condition that would adversely affect the licensee's response to an emergency. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding represented a loss of safety system function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the bounding change to the core damage frequency was less than 1.8E-8 per year (Green). Since the change in core damage frequency was less than 1E 7 per year, the finding was not significant to the larger early release frequency. (See Attachment 2 for analysis results.) This finding did not have a crosscutting aspect because the most significant contributor to the performance deficiency did not reflect current licensee performance.

Enforcement. The inspectors identified a Green non-cited violation of Technical Specification 5.4.1(b) which states, in part, "Written procedures shall be established, implemented, and maintained covering the following activities: The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33." Contrary to the above, the licensee failed to maintain emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1. Specifically, from 1997 to August 21, 2013, the licensee failed to revise emergency operating procedures for reactor pressure vessel control and primary containment control when it determined that the required net positive suction head for the emergency core cooling pump were no longer bounded by the pumps vortex limits. This violation was entered into the corrective action program as Action Request 292153. On August 21, 2013, the licensee implemented a night order giving guidance to monitor the pumps for cavitation and take actions to prevent degraded operation until the procedures are revised. Because this finding was of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2, of the NRC Enforcement Policy.

(NCV 05000397/2013007-07; Failure to Include ECCS Pumps' NPSH Limits in the Emergency Operating Procedures)

2. Failure to Correct a Condition Adverse to Quality with Emergency Operating Procedures

Introduction. The team identified a Green non-cited violation 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for failure to correct a condition adverse to quality. Specifically, the licensee failed to implement a prompt compensatory corrective action to correct an adverse condition in emergency operating procedures that would have led to the loss of emergency core cooling pumps due to inadequate available net positive suction head.

Description. On August 16, 2013, the team identified a condition where the vortex limits for emergency core cooling pumps contained in the Columbia Generating Station emergency operating procedures were no longer conservative compared to the net positive suction head limits of all of the emergency core cooling pumps. (See b.1 above for details.) Upon identification, the operators were directed to institute a "compensatory action for when suppression pool level is below normal (low level alarm): Monitor the ECCS pumps and RCIC pump for cavitation." The issue was entered into the corrective action program as Action Request 292153, on August 16, 2013. The team was notified that a night order would be immediately issued to alert the operators of the adverse condition in the emergency operation procedures. However, the night order was not issued until August 21, 2013, after the team requested a copy of the interim corrective action.

Analysis. The team determined that the failure to implement an interim compensatory corrective action to promptly correct an adverse condition in emergency operating procedures in accordance with 10 CFR 50, Appendix B, Criterion XVI, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating System cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding was more than minor because the procedures were in a condition that would adversely affect the licensee's response to an emergency. Using the NRC Manual Chapter 0609, Appendix A, Exhibit 2, the team determined the finding represented a loss of safety system function; therefore, the senior reactor analyst performed a bounding detailed risk evaluation. The analyst determined that the bounding change to the core damage frequency was less than 1.8E-8 per year (Green). Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency. (See Attachment 2 for analysis results.) The team determined that this finding has a crosscutting aspect in the area of problem identification and resolution, corrective action program component, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. Specifically, the licensee did not implement interim compensatory corrective actions in a timely manner to correct an adverse condition associated with the operation limits of the emergency core cooling pumps in emergency operating procedures. [P.1(d)]

Enforcement. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," which states, in part, "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to this requirement, the licensee failed to assure that conditions adverse to quality were promptly corrected. Specifically, from August 16, 2013, to August 21, 2013, the licensee failed to implement a prompt compensatory corrective action to correct an adverse condition in emergency operating procedures that would have led to the loss of emergency core cooling pumps due to inadequate available net positive suction head. The violation was entered into the corrective action program as Action Request 292437. On August 21, 2013, the licensee implemented a night order giving guidance to monitor the pumps for cavitation and take actions to prevent degraded operation until the procedures are revised. Because this finding was of very low safety significance and has been entered into the licensee's corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2, of the NRC Enforcement Policy.
(NCV 05000397/2013007-08; Failure to Correct a Condition Adverse to Quality with Emergency Operating Procedures)

.2.7 Residual Heat Removal Valve, RHR-V-24A

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the safety-related residual heat removal valve, RHR-V-24A. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Motor operated valve thrust, setpoint, and stroke time calculations.
- Diagnostic tests to validate the adequacy of the valve size, orientation, and location.
- Operational and maintenance history to verify that potentially degraded conditions were being appropriately addressed.
- Calculations and design basis documents to ensure acceptance criteria for tested parameters were valid to support operation under accident conditions.

b. Findings

No findings were identified.

.2.8 Residual Heat Removal Valve, RHR-V-48B

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the safety-related residual heat removal valve, RHR-V-48B. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Motor operated valve thrust, setpoint, and stroke time calculations.
- Diagnostic tests to validate the adequacy of the valve size, orientation, and location.
- Operational and maintenance history to verify that potentially degraded conditions were being appropriately addressed.
- Calculations and design basis documents to ensure acceptance criteria for tested parameters were valid to support operation under accident conditions.

b. Findings

No findings were identified.

.2.9 High Pressure Core Injection Valve Motor, HPCS-V-4

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the high pressure core injection motor, HPCS-V-4. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Schematics and one-line diagrams for the valve motor starter.
- Vendor nameplate data and specifications for the motor.
- Calculations for determining minimum motor terminal voltage under design/licensing basis conditions.
- Calculations for determining minimum contactor terminal voltage under design/licensing basis conditions.
- Selection criteria for the motor starter breaker and motor thermal overload heater selection.

- Environmental design requirements under design/licensing basis conditions.

b. Findings

No findings were identified.

.2.10 4160/480 Vac Transformer, E-TR-8/83

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the 4160/480 Vac transformer, E-TR-8/83. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- One-line diagrams to verify that the revised design conformed to the system requirements.

- Calculations for electrical distribution, system load flow/voltage drop, short-circuit, and electrical protection to verify that transformer capacity and voltages remained within minimum acceptable limits in accordance to nameplate rating data.

- Component maintenance history and corrective action program reports to verify the monitoring of potential degradation.

- Procedures for transformer preventive maintenance, inspection, and testing to compare maintenance practices against industry and vendor guidance.

b. Findings

No findings were identified

.2.11 4160 Vac Circuit Breaker, E-CB-8/83

a. Inspection Scope

The team reviewed the updated safety analysis report, design basis documents, system description, selected drawings, calculations, maintenance and test procedures, and condition reports associated with the 4160 Vac circuit breaker, E-CB-8/83. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- One-line diagrams to verify that the revised design conformed to the system requirements.

- Calculations for electrical distribution, system load flow/voltage drop, short-circuit, and electrical protection to verify that circuit breaker capacity and voltages remained within minimum acceptable limits in accordance to nameplate rating data.

- The protective device settings and circuit breaker ratings to ensure adequate selective protection coordination of connected equipment during worst-case short circuit conditions.

- Procedures for circuit breaker preventive maintenance, inspection, and testing to compare maintenance practices against industry and vendor guidance.

b. Findings

No findings were identified.

.2.12 Reactor Core Isolation Cooling Pump, RCIC-P-1

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the reactor core isolation cooling pump, RCIC-P-1. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history and corrective action program reports.

- Calculations for vortex prevention and available net positive suction head.

- Procedures for preventive maintenance, inspection, and testing.

- Condensate storage tank minimum volume requirement calculations.

- Reactor core isolation cooling pump lubricating oil sample test results.

- Reactor core isolation cooling instrument data sheet.

- Reactor core isolation cooling pump surveillance and trend data.

- Reactor core isolation cooling pump vendor manual.

- Reactor core isolation cooling pump room cooling calculation.

b. Findings

No findings were identified.

.2.13 Reactor Core Isolation Cooling Pump Low Suction Pressure Switch, RCIC-PS-1

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and calibration procedures, and condition reports associated with the reactor core isolation cooling pump low suction pressure switch, RCIC-PS-1. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history and corrective action program reports.
- Procedures for preventive maintenance, inspection, calibration, and testing.
- Vendor manual for reactor core isolation cooling pressure switch, RCIC-PS-6.
- Calculation for the setting range determination of RCIC-PS-6.
- Reactor Core isolation cooling system flow and logic diagrams.

b. Findings

No findings were identified.

.2.14 Low Pressure Core Spray Pump, LPCS-P-1

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the low pressure core spray pump, LPCS-P-1. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history and corrective action program reports
- Calculations for vortex prevention and available net positive suction head
- Procedures for preventive maintenance, inspection, and testing
- Low pressure core spray pump motor lubricating oil sample test results
- Low pressure core spray pump surveillance and trend data
- Low pressure core spray pump and motor vendor manuals
- Low pressure core spray pump room cooling and flooding calculations

- Low pressure core spray system fill verification results
- Low pressure core spray system flow diagrams

b. Findings

No findings were identified.

.2.15 Containment electrical penetration, PEN-RLK-17-7A

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the containment electrical penetration, PEN-RLK-17-7A. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- Component maintenance history and corrective action program reports
- Containment electrical penetration cross sectional diagrams
- Containment electrical penetration equipment qualification files
- Containment electrical penetration vendor manuals
- Containment electrical penetration seismic test data
- Containment electrical penetration construction reports
- Verification no incompatible materials present (e.g. Teflon)
- Verification vent holes installed on inboard electrical junction boxes

b. Findings

No findings were identified.

.2.16 Residual Heat Removal System Pipe Support, RHR-84

a. Inspection Scope

The team reviewed the updated safety analysis report, system description, the current system health report, selected drawings, maintenance and test procedures, and condition reports associated with the residual heat removal system pipe support, RHR-84. The team also performed walkdowns and conducted interviews with system engineering personnel to ensure the capability of this component to perform its desired design basis function. Specifically, the team reviewed:

- System modifications effect on pipe supports.
- Calculations for pipe, concrete expansion anchor, baseplate, and thermal stresses

b. Findings

No findings were identified.

.3 Results of Reviews for Operating Experience:

.3.1 Inspection of the NRC Bulletin 1979-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts"

a. Inspection Scope

The team reviewed the licensee's evaluation of 1979-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts" to verify that the concerns of the bulletin were addressed. The team verified that the licensee's review adequately addressed the issues in the NRC Bulletin.

b. Findings

No findings were identified.

.3.2 Inspection of the NRC Bulletin 1979-14, "Seismic Analyses for As-Built Safety-Related Piping Systems"

a. Inspection Scope

The team reviewed the licensee's evaluation of 1979-14, "Seismic Analyses for As-Built Safety-Related Piping Systems," to verify that the concerns of the bulletin were addressed. The team verified that the licensee's review adequately addressed the issues in the NRC Bulletin.

b. Findings

No findings were identified.

.3.3 Inspection of NRC Bulletin 1988-04, "Potential Safety-Related Pump Loss"

a. Inspection Scope

The team reviewed the licensee's evaluation of the NRC Bulletin 1988-04, "Potential Safety-Related Pump Loss," to verify that the concerns of the bulletin were addressed. The team verified that the licensee's review adequately addressed the issues in the NRC Bulletin.

b. Findings

No findings were identified.

.3.4 Inspection of the NRC Information Notice 2010-23, “Malfunctions of Emergency Diesel Generator Speed Switch Contacts”

a. Inspection Scope

The team reviewed the licensee’s evaluation of Information Notice 2010-23, “Malfunctions of Emergency Diesel Generator Speed Switch Contacts,” to verify that the concerns of the notice were addressed. The team verified that the licensee’s review adequately addressed the issues in the information notice. Additionally, the team reviewed actions completed in AR 228770 to verify that corrective actions were being implemented.

b. Findings

No findings were identified.

.4 Results of Reviews for Operator Actions:

The team selected risk-significant components and operator actions for review using information contained in the licensee’s probabilistic risk assessment. This included components and operator actions that had a risk achievement worth factor greater than two or Birnbaum value greater than 1E-6.

a. Inspection Scope

The team observed operators during simulator scenarios associated with the selected components, as well as observing simulated actions in the plant.

The selected operator actions were:

- Provide Alternate Cooling to Division 1 and Division 2 Switchgear Rooms
- Align Tower Make-up System to Fill Service Water Spray Ponds
- Reduce Station Battery Loads During Station Blackout
- Station Blackout Control Room Actions
- Vent Containment Without AC or DC Power

b. Findings

No findings were identified.

4 OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

The team reviewed actions requests associated with the selected components, operator actions, and operating experience notifications. Any related findings are documented in prior sections of this report.

4OA6 Meetings, Including Exit

On August 22, 2013, the team leader presented the preliminary inspection results to B. MacKissock, Plant Manager, and other members of the licensee's staff. The licensee acknowledged the findings during the meeting. While some proprietary information was reviewed during this inspection, no proprietary information was included in this report.

ATTACHMENT 1 – SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
M. Davis, Manager, Radiation Protection
P. Donavin, Manager (Acting), Design Engineering
J. Dunn, Engineer, Design Engineering
C. England, Manager, Organizational Effectiveness
D. Gregoire, Manager, Regulatory Affairs
W. Guldemond, Manager, Recovery, Site Vice President Office
K. Hudson, Coordinator, Corrective Action Program, Organization Effectiveness
A. Javorik, Vice President, Engineering
S. Kartchner, Engineer, System Engineering
D. Kettering, Engineer, System Engineering
C. King, Assistant Plant Manager
B. MacKissock, Plant Manager
T. McLaen, Engineer, Design Engineering
R. Parmelee, Manager, Operations Support
T. Rak, Supervisor, Design Engineering
M. Rice, Design Engineering
N. Robles, Engineer, Technical Services
J. Sims, Manager, System Engineering
R. Torres, Manager, Quality Assurance
J. R. Trauvetter, Supervisor, Compliance, Regulatory Affairs
A. Vorpagel, Engineer, Design Engineering
D. Wolfgramm, Senior Engineer, Licensing, Regulatory Affairs

NRC personnel
J. Groom, Senior Resident Inspector
M. Hayes, Resident Inspector
G. Matharu, Senior Electrical Engineer, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000397/2013007-01	NCV	Failure to Support the Ability to Restore Class 1E Diesel Generator Standby Power and Recover from Station Blackout (SBO) Conditions (Section 1R21.2.1)
05000397/2013007-02	NCV	Failure to Demonstrate Independence Requirements of IEEE 308-1974 for Divisions 1 and 2 Vital Instrumentation and Control Power Systems (Section 1R21.2.2)

Opened and Closed

05000397/2013007-03	NCV	Failure to Establish Emergency Procedures for Filling and Venting Diesel Fuel Oil Tanks after Tornado Damage (Section 1R21.2.3)
05000397/2013007-04	NCV	Failure to Update the FSAR for the Cleaning and Inspection Frequency of the Diesel Fuel Oil Storage Tanks (Section 1R21.2.3)
05000397/2013007-05	NCV	Failure to Provide Technical Basis for Assuming Turbulent Mixing of Diesel Combustion Air (Section 1R21.2.4)
05000397/2013007-06	NCV	Failure to Analyze the Effect of System, Test Source, and Transient Harmonics on Proper Operation of Undervoltage Relays (Section 1R21.2.5)
05000397/2013007-07	NCV	Failure to Include ECCS Pumps' NPSH Limits in the Emergency Operating Procedures (Section 1R21.2.6)
05000397/2013007-08	NCV	Failure to Correct a Condition Adverse to Quality with Emergency Operating Procedures (Section 1R21.2.6)

LIST OF DOCUMENTS REVIEWED

Calculations

NUMBER	TITLE	REVISION/DATE
10.04.72	WPPSS NP #2 Analyze Vortex Formation at the HPCS/RCIC Suction Inlets in the Condensate Storage Tanks	0
10.07.77	Residual Heat Removal System Cavitation Provisions	0
2.05.01	Spring Charging Motor Inrush	11
2.12.58	Second Level Undervoltage Relay Settings for SM-4, SM-7, and SM-8	5
25709-000-30R-H01G-00001-000	Dispersion analysis for WNP-2 nitrogen tank failure due to tornado missile impact	Draft
3808-05	Pressure Drop Calculation - RHR System	August 19, 1977
5.17.14	RHR Shutdown Cooling Loop – Head Loss and Press in the RHR H/X	1

Calculations

NUMBER	TITLE	REVISION/DATE
5.19.10	High Pressure Core Spray System – ECCS Minimum NPSH Calculations - Reg. Guide 1.1 Rev. 0	0
5.19.10	High Pressure Core Spray System – ECCS, Minimum NPSH Calculations – Reg. Guide 1.1, Rev. 0	0
5.19.15	ECCS Relief Valve Setpoint	3
5.20.10	Pressure Drop Calculation – Reactor Core Isolation Cooling System	2
5.20.19	NPSH of RCIC Pump – Maximum Allowable Suppression Pool Temperature	0
5.44.08	Anticipated Maximum Internal Pressure – Pump Discharge Piping	1
5.51.58	Flooding Safe Shutdown Analysis	4
5.51.60	High Energy Flooding Analysis	1
6.92.19	Motor Control Centers Seismic Supports	0
6.93.19	Radwaste MCC Base Restraint	0
8.14.61B	Stress Analysis of ISO:M200-SHT106	7
8.14.61C	Status As-Built Verification of Piping Calculation	9
8.16.654	RHR-84 Pipe Support Review/Redesign	3
BR File #49-00-00913	Seismic Test Report	0
CE-02-87-33	Calculation for Liquid Nitrogen Tank CN-TK-1 Support	0
E/I-02-89-02	Evaluation of the Design of 120 VAC Starter Control Circuits for 480 VAC Motors	2
E/I-02-90-01	Low Voltage System Loading Calculation	9

Calculations

NUMBER	TITLE	REVISION/DATE
E/I-02-91-03	Div. 1, Div. 2, and Div. 3 Diesel Generator Loading Calculation	16
E/I-02-91-1011	Setting Range Determination for Instrument Loops HPCS-LS-1A and HPCS-LS-1B	1
E/I-02-92-1053	Setting Range Determination for RCIC-PS-22A	0
E/I-02-92-11	Setting Range Determination for RCIC-PS-6	0
E/I-02-98-1002	Setpoint Determination for COND-LS-41A	0
EES-5	General Fuse Selection Criteria and the Electrical Protection of 460VAC and 125-250VDC Motors	7
E/I-02-09 App B3.3	AC Short Circuit Current Analysis for 6.9kV, 4.16kV and 480 Systems	3
E/I-02-87-07	Load Flow & Voltage Analysis for the Plant Main Buses AC Distribution Systems	6
E/I-02-92-09	AC Short Circuit Current Analysis for 6.9kV, 4.16kV and 480 Systems	2
E/I-02-92-17	AC Short Circuit Current Analysis for 6.9kV, 4.16kV and 480 Systems, Pages 5.162-5.164, 5.061-5.071, 5.141-5.143, 5.146-5.147, 5.010-5.015	1
E/I-02-92-17 App A	AC Short Circuit Current Analysis for 6.9kV, 4.16kV and 480 Systems, Pages 9-12	1
EQ-02-92-10	Diesel Generator equipment Temperature Capability Evaluation	3
ME-02-02-02	Reactor Building Flooding Analysis	2
ME-02-02-27	MOV Thrust and Setpoint Calculation – RHR-MO-048A	1
ME-02-04-09	Pressure Drop Verification for RCIC System	0
ME-02-12-07	Attachment 4 Minimum Flow & Closed Discharge Operation (RCIC)	June 5, 1974

Calculations

NUMBER	TITLE	REVISION/DATE
ME-02-88-03	Installation of Ash Fall Prefilters as Permanent Filters and Pressure Loss Through Air Intake System for Ash Fall Event	2
ME-02-90-16	Pressure Drop Verification for LPCS System	2
ME-02-92-43	Room Temperature Calculation for DG Building, Reactor Building, Radwaste Building and Service Water Pumphouse Under Design Basis Accident Conditions	8
ME-02-93-17	RHR Shutdown Cooling Temperature Transients and Profiles	0
ME-02-99-03	Alternate decay heat removal using RHR with suction from the Fuel Pool	0
NE-02-03-05	EOP/SAG calculations	1
NE-02-03-06	EOP/SAG Calculations	1
NE-02-82-11	Head Loss Calculations on ECCS Suppression Pool Suction Strainers	0
NE-02-88-06	Safety Related Motor Operated Valve Functional Review	0
QID 216001	Seismic capabilities	15
QID382003-5	Electrical Penetration Assembly seismic analysis	2

Procedures

NUMBER	TITLE	REVISION/DATE
10.2.14	Maintenance Coating Program	26
10.25.1	Inspections and Cleaning Division 1, E-IN-3A and E-IN-3B, and Division 2, E-IN-2A and E-IN-2B, Inverters	26

Procedures

NUMBER	TITLE	REVISION/DATE
10.27.86	RCIC Turbine Trip on Low Pump Suction Pressure Calibration	3
10.7.1	RCIC Turbine (RCIC-DT-1) Inspection/Repair/Overhaul	13
4.601.A2	RHR B Pump Discharge Press High/Low	24
4.800.C5	800.C5 Annunciator Panel Alarms	27
8.4.42	Thermal Performance Monitoring of RHR-HX-1A and RHR-HX-1B	11
ABN-WIND	Abnormal procedure wind	13
ESP-RHR-Q902	RHR Pump B Time Delay (LPCI Mode) – CFT/CC	11
ESP-RLY278345-X301	4.16 kV Emergency Bus Undervoltage Relays (E-RLY-27/8/3, E-RLY-27/8/4, AND E-RLY-27/8/5) - CC	10
ESP-SM8UV-M401	4.16 kV Emergency Bus Degraded Voltage (SM8) - CFT	12
ISP-HPCS-Q901	HPCS System Transfer on CST Low Level - CFT/CC	7
ISP-MS-Q912	ECCS – LPCS (A) and LPCS Valve Permissive on Low Reactor Pressure – Channels A and C – CFT/CC	5
ISP-RCIC-Q902	RCIC Suction Transfer on CST Low Level - CFT/CC	8
MI-3.4	Coatings Daily Work Practices	15
MMP-DO-E002	Pressure test of the diesel fuel oil system	2
MMP-RCIC/IST-F701	RCIC-RD-1 and RCIC-RD-2 Replacement	2
OSP-DO	DO-P-1A operability	12
OSP-ELEC-M701	Diesel Generator 1 - Monthly Operability Test	53

Procedures

NUMBER	TITLE	REVISION/DATE
OSP-ELEC-M702	Diesel Generator 2 - Monthly Operability Test	58
OSP-ELEC-S701	Diesel Generator 1 Semi-Annual Operability Test	53
OSP-ELEC-S702	Diesel Generator 2 Semi-Annual Operability Test	54
OSP-ELEC-W102	Electrical Distribution Subsystem Breaker Alignment and Power Availability Verification	26
OSP-LPCS/IST-Q702	LPCS System Operability Test	34
OSP-LPCS-M101	LPCS Fill Verification	6
OSP-RCIC/IST-Q701	RCIC Operability Test	51
OSP-RCIC/IST-R701	RCIC Check Valve Operability - Refueling Shutdown	5
OSP-RHR/IST-Q703	RHR Loop B Operability Test	43
OSP-RHR-A701	RHR Loop A Keep Fill Integrity Test	9
OSP-RHR-A702	RHR Loop B Keep Fill Integrity Test	8
PPM 1.5.13	Preventive Maintenance Optimization Living Program	28
SOP-DG1-START	Emergency Diesel Generator (Div. 1) Start	25
SOP-DG2-START	Emergency Diesel Generator (Div. 2) Start	24
SOP-FO-OPS	Diesel fuel oil filter/polisher/transfer system	6
SOP-RHR-Injection	RHR RPV Injection	3
SOP-RHR-SDC	RHR Shutdown Cooling	24
SOP-RHR-STBY	Placing RHR in Standby Status	4

Procedures

NUMBER	TITLE	REVISION/DATE
SWP-CAP-01	Corrective Action Program	27.2
SWP-CHE-02	Chemical Process management and Control	20
TP*8.3.151	MCC-4A Contactor Degraded Voltage Pickup Test	6
TSP-LPCS/RHRA-B501	LPCS/RHRA LSFT	10
TSP-RCIC-B801	RCIC System Leakage Surveillance	2

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02-210A-08, Sheet 11	Containment Inerting System Equipment Pad (Resteel)	0
02-210A-08, Sheet 12	Containment Inerting System Equipment Pad (Lift Dwg)	1
02E51-05,5	Reactor Core Isolation Cooling – Instrument Data Sheet	June 24, 1974
2-2E51-06	Reactor Core Isolation Cooling Pump – Characteristic Curve Sheet	November 10, 1971
2648-3	18”-300# Globe Stop, Bolted Bonnet, Cast Carbon Steel Trim, Butt Weld Ends Motor Operator SMB-3	1
35-836R	Outer Sleeve Cable Assembly	0
5.1.1	RPV Control	19
5.2.1	Primary Containment Control	20
556-30530	Permutit Outline and Assembly Flow Limiter nozzles	February 29, 1976
761E428	Heat Exchanger	June 22, 1979

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807E173TC	RCIC Elementary Diagram & Relay Tabulation	36
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COND-4631-3	RCIC-LS-15A on RCIC-HPCS Switchover Standpipe	6
COND-4631-4	RCIC-LS-15B on RCIC-HPCS Switchover Standpipe	6
D-220-3500-6.0-RCIC-PS-21	Tube Erection Isometric for RCIC-PS-21 & PS-6, and RCIC-PT-5 & PI-2 Reactor Building Floor El. 422'-3"	5
E-2677	Westinghouse Canister Type	1
E-2722	Canister Cable Support	A
E-3698	Modular Design Penetration Types 1-5,7	D
E502-1	Main One Line Diagram	50
E502-2	Main One Line Diagram	60
E503-9	Auxiliary One Line Diagram	73
E504-1	Vital One Line Diagram	1
E528-49	MCC Equip. Overload Summary	24
E535	Connection Wiring Diagram Motor Control Centers Sheet No. 18C	20
EWD-46E-076	AC Electrical Distribution Systems 480V Substation 83 4.16kV FDR Breaker E-CB-8/83 SH1	15
EWD-46E-077	AC Electrical Distribution Systems 480V Substation 83 4.16kV FDR Breaker E-CB-8/83 SH2	9
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EWD-46E-248	Electrical Wiring Diagram AC Distribution System Main Control Room UPS Power Panel E-PP-8AA	43
EWD-47E-003	Electrical Wiring Diagram Standby AC Power System Diesel Generator Breaker E-CB-DG1/7	23
EWD-47E-031	Electrical Wiring Diagram Standby AC Power System Diesel Generator 1 Excitation System	11
EWD-47E-042	Electrical Wiring Diagram Standby AC Power System Diesel Generator 1 Engine Start/Stop Controls	14
EWD-47E-046	Electrical Wiring Diagram Standby AC Power System Diesel Generator 1 Governor Speed Control	9
EWD-47E-048	Electrical Wiring Diagram Standby AC Power System Diesel Generator 1 Unit Protection Circuits	14
EWD-6E-001	Electrical Wiring Diagram – Reactor Core Isolation Cooling System – MOV RCIC-V-1 (Turbine Trip and Throttling Valve)	18
EWD-6E-001A	Electrical Wiring Diagram – Reactor Core Isolation Cooling System – MOV RCIC-V-1 (Turbine Trip and Throttling Valve)	5
EWD-6E-031	Electrical Wiring Diagram - Reactor Core Isolation Cooling System - MOV RCIC-V-8 (E51-F008)	22
EWD-7E-016	Electrical Wiring Diagram High Pressure Core Spray System MOV HPCS-V-4	20
EWD-7E-016A	Electrical Wiring Diagram High Pressure Core Spray System MOV HPCS-V-4	1
F-29APKD500X3-A	APKD Pump	August 7, 1972
I-810807-A	Suppression Pool Plate Strainer	August 7, 1981
M200-SHT106	RHR Pipe Supports	6

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M512-4	Diesel Oil Day Tank	10
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M521-3	Flow Diagram Residual Heat Removal Loop C	9
M527-1	Flow Diagram – Condensate Supply System – Reactor, Turbine Gen., & Radwaste Buildings, Radwaste/Reactor Building Corridor, & Yard	102
M551	Flow Diagram HVAC Circulating water, Make Up Water & Service Water Pump Houses & Diesel generator Building	62
RCIC-656-5.8	Suction from Suppression Pool to RCIC Pump-P-1	17
S830	Structural Containment Vessel Lower Spray Head Pipe	1
SK-20 SHT. 1	DO Storage Tank Outline HP Core Spray	9
WNP2-ECCS 8016-1300	WPPSS Nuclear Plant No. 2, Sure-Flow Strainer – Module Type 3, Physical Design Information	December 8, 1997

Design Basis Document

NUMBER	TITLE	REVISION
16	Design Specification for Section 16E Electrical Penetration Assemblies	8
315	Reactor Core Isolation Cooling System	8
316	Low Pressure Core Spray System	8
317-AC	AC Electrical Distribution System	2
317-DC	DC Electrical Distribution System	1

Design Basis Document

NUMBER	TITLE	REVISION
Division 200 Section 206	Design Specification for Station Blackout	3
Division 200 Section 201	Design Specification for Electrical Separation Requirements	11

Engineering Changes

NUMBER	TITLE	REVISION/DATE
EC 0000011984	125V (DIV 1) Control Circuit Evaluation	0
EC 0000012249	Vital Instrument Bus Circuit Isolation and Coordination Requirements	0
EC 008902340A	Replace Inverter 2 & 3	0
EC 0000001351	5.17.19 Rev. 3, Effect of As Built Strainer Head Losses and the Increase in Suppression Pool Temperature on RHR	November 29, 2001

Action Requests (AR/CR-…)

183963	191350	186407	197734	205297
208348	209463	223039	223042	001742
044241	035641	271352	183656	228770
271177	250120	286635	271764	

Action Requests Generated During the Inspection (AR/CR-…)

290866	290877	290885	290907	290912
290914	290926	290956	290974	290976

Action Requests Generated During the Inspection (AR/CR-…)

291040	291042	291062	291118	291143
291144	29111	291160	291162	291164
291166	291197	291224	291225	291235
291248	291277	291283	291285	291320
291324	291396	291410	291487	291543
291590	291593	291624	291665	291751
291762	291763	291764	291921	291929
291935	292031	292105	292119	292129
292144	292151	292153	292215	292241
292251	292253	292266	292322	292326
292352	292357	292361	292362	292402
292405	292419	292420	292437	

Work Orders

291410-01	2023762-01	2046724-01	2046725-01	2007290-01
1135786	1138038	1177907	1130484	2035456
1183485	1177922	2034409	1081906	2006662
1185541	1025933	1191243	1127993	1137586
2006301-01	2017725-03	2046724	2024498	2035069
2022071-01	2036179-01	2017725-02	2015791-08	2034581

Work Orders

2033241	1141853	1179142-01	2000170

Preventive Maintenance Requirements (PMR-)

9670	9727	9699	6966	7795

Problem Evaluation Requests (PER-)

299-1210	299-1817	294-0901	293-0053

Vendor Documents

NUMBER	TITLE	REVISION/DATE
PS-G-1002	ABB, Power Substation Transformers	Dec 1993
I.B. 6513C80F	Eaton Cutler-Hammer, Instruction for Installation, Operation, and Maintenance of Type DHP-VR Vacuum Replacement Circuit Breakers for DHP Switchgear	Nov 2003
ABB IB 7.4.1.7-7	Instructions, Single Phase Voltage Relays	E
N-621	Pump 29APKD-3, Ingersol Rand Certified Head Capacity Curve	0
0801MP004399-1	Flowserve Certified Head Capacity Curve	September 8, 2008

Miscellaneous

NUMBER	TITLE	REVISION/DATE
	LPCS-P-1 Surveillance Data (01/03/03 – 06/13/13)	
	RCIC-P-1 Surveillance Data (01/22/03 – 12/14/12)	
	Email from D.E. Gregory of Flowserve to Columbia's D. Reising	August 15, 2013

Miscellaneous

NUMBER	TITLE	REVISION/DATE
	Phone Conversation Record, Woodward Governor Component Operability at Elevated Temperatures	June 2, 1992
	RHR System Health Report	Current, no date
02-01,1,1	Instruction Manual for Vendor Supplied Instruments	3
02-02E51-07	Instruction Manual for Terry Turbine Maintenance	2
028337 0903	Product Data Bulletin	
028337 1689	General Specifications SS Plus	
028337 1693	General Specifications SS Plus	
028337 1969	General Specifications SS Plus	
02E12-08, 10	Ingersol Dresser, RHR Pumps and Graphalloy Bushings	3
02E21-06,7	Low Pressure Core Spray Pump	7
02E51-06,17	Instruction Manual for RCIC Pump - Type CP	3
02E51-07	Instruction Manual for RCIC Turbine	37
41B-00,75	Anchor darling Valves, Globe, Tilting Disc Check, and Swing Check Valves	5
5.0.10	Flowchart Training Manual	17
5059SCREEN-12-0193	LDCN-FSAR-12-036	February 25, 2013
946Y	Ingersol Rand Emergency Core Cooling (ECCS) Pumps	February 10, 1989
C-30181	NRC Bulletin 88-04, Review of Min Flow Rates	January 27, 1989
CGS-FTS-0168	Columbia Generating Station Alternative Source Term	2

Miscellaneous

NUMBER	TITLE	REVISION/DATE
CR# 2-06-03322	Calculation E/I-02-91-1011, Appendix C, did not address all scenarios resulting in a non-conservative TSSR	May 3, 2006
CVI 02-942-00	Schematic 15 KVA Inverter 125VDC 120/240 VAC 1 Phase 60 HZ Dwg. No. 20-106672	2
CVI 942-00,15	Solidstate Controls, Inc. 15KVA Inverter/Static Switch	4
CVI-767-00-142	GE Power Systems, Instruction Manual for Power System Harmonic Study	2001
E514-8	4.16 kV Switchgear SM-8 Relay Settings List	20
G02-88-150	Response to IEB 88-04, “Potential Safety Related Pump Loss”	July 8, 1988
G02-88-208	Response to IEB 88-04, “Potential Safety Related Pump Loss”	September 28, 1988
G02-89-062	Response to station blackout rule using HPCS division III as alternate AC power	April 17, 1989
G02-91-128	Additional Information Regarding Station Blackout	July 1, 1991
G02-93-079	Response to IEB 88-04, “Potential Safety Related Pump Loss”	April 1, 1993
G02-95-212	Request Approval to Revise Tornado Design Criteria	October 10,1995
G12-91-001	Review of Unanalyzed Failure Mode for the Rupture of the Liquid Nitrogen Tank at WNP-2	January 2, 1991
GO2-06-053	60-Day Response to the NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"	April 3, 2006
IEEE 141	IEEE Recommended Practice for Electric Power Distribution for Industrial Plants, Table 9-6	1993
IST Trend	RHR-P-2B Tech Spec Margin	January 1, 2013

Miscellaneous

NUMBER	TITLE	REVISION/DATE
Letter to NRC GO2-94-292	WNP-2, OPERATING LICENSE NPF-21 NRC INSPECTION OF WNP-2, EMERGENCY OPERATING PROCEDURES (NRC INSPECTION REPORTS NO. 91-27 AND 94-01)	December 30, 1994
Letter to NRC, 1300.2-927S	Response to IEB 88-04, Potential Safety Related pump Loss	September 28, 1988
MOT-BKR-1-1 (SM-8)	Westinghouse Switchgear MOT	
MOT-BKR-1-2 (E-CB-8/83)	Cutler-Hammer DHP-VP Breakers MOT	
MOT-XFMR-1-1	Load Center Transformer MOT	
Night Order 1480	Reference CR 292153	August 21, 2013
PED 218-CS-4538	Technical direction for fabricating vent holes in NEMA-4 junction boxes inside primary containment	March 8, 1982
QID 221001EL	Environmental Qualification Limitorque Vol. 01B	
SD000168	Emergency Core Cooling Systems (ECCS) – System Description	11
SD000192	Low Pressure Core Spray – System Description	12
SS2-PE-93-0671	Testing and Inspection of the Diesel Oil System to Meet ASME Section XI and Washington State Requirements for Underground Storage Tanks	September 27, 1993
TM-2115	TSG-Mechanical Engineer	4
TM-2123	Design Basis Evaluation of Temperature, Pressure and Humidity Limits in FSAR Table 3.11-1	February 29, 2000

ATTACHMENT 2 – DETAILED RISK EVALUATIONS FOR THE COLUMBIA GENERATING STATION COMPONENT DESIGN BASES INSPECTION

Section 1R21.2.2: NCV 05000397/2013007-02; Failure to Demonstrate Compliance with IEEE 308-1974 for Independence of Divisions 1 and 2 Vital Instrumentation and Control Power Systems

The team completed the initial significance determination for the inverter finding. The team used the NRC Inspection Manual 0609, Attachment 4, "Initial Characterization of Findings," to evaluate this issue. The finding required a detailed analysis because both inverters could fail during a seismic induced loss of offsite power event. The finding was potentially significant for external events. Therefore, the senior reactor analyst performed a bounding detailed risk evaluation.

The analyst used the NRC's Columbia Generating Station Standardized Plant Analysis Risk (SPAR) model, Revision 8.16, with a truncation limit of 1E-11. The analyst assumed a full year exposure period.

Seismic initiators could cause a loss of offsite power and induce the failure of non-safety loads attached to each inverter. For a narrow range of non-safety component electrical faults, each inverter could over-load and fail prior to fuse operation. Once the fuses cleared, the inverters would automatically reset and recovery. This would have no impact on the starting and loading of the emergency diesel generators and other plant components, but operators could briefly lose power to plant instruments and control room indications for less than one minute. The oxygen and hydrogen monitors would not automatically restart, but these components would be used significantly later (for indication only) and could be easily recovered. These components are not risk important and are not included in the NRC's SPAR model.

Based on the above, the analyst could not use the SPAR model to determine the change in core damage frequency for this finding. However, the analyst determined, qualitatively, that the change to the core damage frequency (Δ-CDF) would be less than 1E-7 per year (Green). The frequency for a seismic induced loss of offsite power at the Columbia Generating Station was 1.8E-4 per year and all of the equipment that would automatically start and mitigate the accident would remain functional.

Since the affected components were not modeled in the NRC's SPAR model, no dominant accident sequences were identified. However, operators could be distracted when all instrumentation briefly failed during an event. The inverter's automatic recovery features helped to minimize the risk.

Large Early Release Frequency: Since the change in core damage frequency was less than 1E-7 per year, the finding was not significant to the larger early release frequency.

Section 1R21.2.3: NCV 05000397/2013007-03; Failure to Establish Emergency Procedures for Filling and Venting Diesel Fuel Oil Tanks after Tornado Damage

The team completed the initial significance determination for the nitrogen tank tornado vulnerability. The team used the NRC Inspection Manual 0609, Attachment 4, "Initial Characterization of Findings," to evaluate this issue. The finding required a detailed analysis because it was potentially risk significant for external events (tornados). Therefore, the senior reactor analyst performed a bounding detailed risk evaluation.

Tornado Frequency: About one out of every three tornadoes is classified as "strong." Strong tornadoes have an average path length of 9 miles and a path width of 200 yards (approximately 1 square mile of land is affected). Although very rare, about 2 percent of tornados are violent. Violent tornadoes can last for hours. Average path lengths and widths are 26 miles and 425 yards, respectively. (See http://www.weatherexplained.com/Vol-1/Tornadoes.html)

Since strong tornados can affect approximately 1 square mile, weaker tornados, on average, would affect significantly less than 1 square mile. Most tornados are of the weaker variety. Violent tornados can affect approximately 6 to 7 square miles (on average), but are relatively rare. Therefore, the analyst conservatively assumed that the average tornado would affect 1 square mile of land.

The average number of tornados in the state of Washington per year was 1 (http://www.erh.noaa.gov/cae/svrwx/tornadobystate.htm).

The total area for the state of Washington was 71,300 square miles (http://www.enchantedlearning.com/usa/states/area.shtml).

Plant Area: For this risk evaluation, the analyst assumed that the Columbia Generating Station and switchyard occupied one square mile of land. This was conservative, in that this equipment occupied less than one square mile.

The analyst conservatively assumed that a tornado within a 1 square mile area would cause a loss of offsite power and cause physical damage to the nitrogen tank. This in turn would cause all three emergency diesel generators to fail. The diesel generators would be recoverable when the nitrogen dissipated to a normal concentration (no longer than 1.0 hour). Because a tornado striking the plant would not likely directly hit the nitrogen tank, or generate large debris that would directly hit and damage the nitrogen tank, this was a very conservative assumption.

Tornado Frequency: The frequency of a tornado hitting the Columbia Generating Station was:

$$\lambda = 1 \text{ tornado per year} \times 1 \text{ square mile} / 71{,}300 \text{ square miles} = 1.4\text{E-5 tornado per year.}$$

Approximately 6 feet of the fill and vent lines were exposed to damage from a tornado and/or tornado generated missiles. This was a relatively small target. Since a tornado that affected offsite power was unlikely to also cause significant damage to the fill and vent lines, the analyst reduced the tornado frequency by one order of magnitude, which was still conservative. The resultant frequency was 1.4E-6 tornado per year.

Change in Core Damage Frequency: The analyst used the NRC's the Columbia Generating Station Standardized Plant Analysis Risk (SPAR) model, Revision 8.16, with a truncation limit of 1E-11. The analyst assumed a full year exposure period.

The analyst calculated the change in core damage frequency considering a loss of offsite power (LOOP) coincident with the failure of all three emergency diesel generators. The analyst set the basic events for a grid centered LOOP and the common cause diesel generator failure to start to 1.0. The analyst allowed the emergency diesel generator and offsite power recovery events to occur. The analyst solved only the grid centered LOOP sequences. The conditional core damage probability was 8.5E-3.

The Δ-CDF was 1.4E-6 × 8.5E-3 = 1.2E-8 per year. (Green) This value was bounding

The dominant core damage sequences included tornado induced losses of offsite power, structural failure of the tornado fill and vent lines and the consequential failure of the emergency diesel generators because of the damaged fill and vent line. The low frequency of tornado initiators helped to reduce the risk.

Large Early Release Frequency: Since the Δ-CDF was less than 1E-7 per year, the finding was not significant to the larger early release frequency.

Section 1R21.2.4: NCV 05000397/2013007-05; Failure to Provide Technical Basis for Assuming Turbulent Mixing of Diesel Combustion Air

As established for the previous issue, the frequency for a tornado at the Columbia Generating Station was 1.4E-5 tornado per year.

Change in Core Damage Frequency: The analyst used the NRC's the Columbia Generating Station Standardized Plant Analysis Risk (SPAR) model, Revision 8.16, with a truncation limit of E-11. The analyst assumed a full year exposure period.

The analyst calculated the Δ-CDF considering a loss of offsite power (LOOP) coincident with the failure of all three emergency diesel generators. The analyst set the basic events for a grid centered LOOP and the common cause diesel generator failure to start to 1.0. The analyst allowed the emergency diesel generator and offsite power recovery events to occur.

The analyst noted that the emergency diesel generator recovery basic events involved diesel failures of all types, not just this narrow failure mode. Compared to other failure modes, the excessive nitrogen failure mode was much easier to resolve (it was self-clearing). After 1.0 hour the diesels should be easily recoverable. To account for this difference, the analyst reduced the diesel non-recovery probabilities by one order of magnitude. The analyst solved only the grid centered LOOP sequences. The conditional core damage probability was 8.5E-4.

The Δ-CDF was 1.4E-5 per year × 8.5E-4 = 1.2E-8 per year. (Green) This value was bounding.

The dominant core damage sequences included tornado induced losses of offsite power, structural failure of the nitrogen tank, and the failure of the emergency diesel generators because of excessive nitrogen in the air intakes. The low frequency of tornado initiators helped to reduce the risk. This finding is not representative of current licensee performance and therefore did not have a crosscutting aspect.

Large Early Release Frequency: Since the Δ-CDF was less than 1E-7 per year, the finding was not significant to the larger early release frequency.

Section 1R21.2.6: NCV 05000397/2013007-07; Failure to Include ECCS Pump NPSH Limits in the Emergency Operating Procedures, and NCV05000397/2013007-08; Failure to Correct a Condition Adverse to Quality with Emergency Operating Procedures

The team completed the initial significance determination for the inverter finding.
The inspector used the NRC Inspection Manual 0609, Attachment 4, "Initial Characterization of Findings," to evaluate this issue. The finding required a detailed analysis because, during a few scenarios, suppression pool level could be so low that the emergency core cooling system pumps could fail because of inadequate net positive suction head (NPSH). Therefore, the safety functions could be lost. The senior reactor analyst performed a bounding detailed risk evaluation.

Under all of the design basis accident scenarios (safety-related scenarios), pump NPSH limits would not be challenged. Normal suppression pool levels alone would ensure adequate NPSH. A significant loss of suppression pool inventory would need to occur prior to challenging pump operability, which would require containment failure.

Change in Core Damage Frequency: The pump with the least NPSH margin was the high pressure core spray (HPCS) pump. This pump would approach the NPSH limits with an approximate 4 foot suppression pool level during large break loss of coolant accident (LOCA) scenarios. During other accident sequences, the HPCS pump could be challenged when and if the suppression pool lost 20 feet of inventory. (The remaining pumps would only be affected during the large break LOCA sequences.)

The analyst broke the evaluation up into two segments. The first included the large break LOCA sequences and the second involved the remainder of the applicable accident sequences. The analyst used the NRC's the Columbia Generating Station Standardized Plant Analysis Risk (SPAR) model, Revision 8.16, with a truncation limit of 1E-11. The analyst assumed a full year exposure period.

Large Break LOCA Sequences: Prior to pump failure, a large break LOCA would need to occur followed by a consequential containment failure. The nominal large break LOCA frequency was 1E-5 per year. In order to challenge containment integrity, both divisions of residual heat removal (RHR) would need to fail. The analyst solved a modified residual heat removal system fault tree to fail just the two heat removal divisions. The resultant failure probability for both divisions was 8.9E-4. The Δ-CDF for a large break LOCA coincident with the failure of the division I and II RHR trains was 1E-5 per year × 8.9E-4 = 9E-9 per year. This frequency bounded the Δ-CDF for the large break LOCA sequences.

Remainder of the Accident Sequences: For the remainder of the sequences, only the HPCS was affected. Containment failure coincident with a 20 foot loss of suppression pool inventory would be needed prior to HPCS pump failure. The analyst neglected the transient events where offsite power remained functional. These included events where the condenser but condensate pumps were available. The additional non-safety equipment made these sequences much less likely to result in containment failure and the loss of suppression pool inventory. The combined initiating event frequencies were 6.2E-2 per year.

As noted earlier, the analyst assumed that both trains of RHR would need to fail in order to drive containment failure. However, operator failure to preventively vent containment periodically would still be required for gross containment failure. In addition, efforts to recovery suppression pool level would also need to fail. Operators could recover condensate storage tank level by using a temporary fire pump and refilling the tank. Suppression pool level would start to recover when the HPCS or the reactor core isolation cooling system used the condensate storage tank to feed the reactor vessel and containment.

The RHR failure probability was 8.9E-4. The analyst assumed the nominal human reliability failure probability of 1.1E-2 for 1) failure to vent containment; and 2) failure to refill the condensate storage tank. This last assumption was very conservative because it would take considerable time to lose 20 feet of suppression pool inventory. The expansive time available would normally lead to lower human error failure probabilities. The Δ-CDF was bounded by the combined initiating event frequencies multiplied by the probability of RHR failure and the noted human reliability events.

$$\Delta\text{-CDF} < 6.2\text{E-}2 \times 8.9\text{E-}4 \times 1.1\text{E-}2 \times 1.1\text{E-}2 = 6.7\text{E-}9 \text{ per year}$$

External Events: The analyst noted that the frequencies for the seismic induced loss of offsite power events as well as the fire induced loss of offsite power events were small compared to the initiating events frequencies already used in this analysis. Inclusion of these events in would not affect the results in a significant way. Therefore, the analyst did not consider these events further.

Total Change in Core Damage Frequency: The total Δ-CDF was the sum of the Δ-CDF contributors. The total Δ-CDF was bounded at Δ-CDF = 1.5E-8 per year (Green)

The dominant sequences included large break loss of coolant accidents (with suppression pool screen debris loading), containment failure (which allows a loss of inventory), followed by the failure emergency core cooling system pumps. The low frequency of the large break loss of coolant accidents combined with the need to lose large amounts of inventory from containment helped to minimize the risk.

Large Early Release Frequency: Since the change to the core damage frequency was less than 1E-7/year, this finding was not a significant contributor to the large early release frequency.