UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E. LAMAR BLVD.
ARLINGTON, TX 76011-4511

November 25, 2014

EA-14-187

Louis P. Cortopassi, Vice President
and Chief Nuclear Officer
Omaha Public Power District
Fort Calhoun Station FC-2-4
P.O. Box 550
Fort Calhoun, NE 68023-0550

SUBJECT: FORT CALHOUN STATION – MANUAL CHAPTER 0350 INSPECTION REPORT AND FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION; NRC INSPECTION REPORT NO. 05000285/2013018

Dear Mr. Cortopassi:

On October 15, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed a team inspection at the Fort Calhoun Station. The inspection focused on the station's high energy line break and environmental qualification programs and the design change and modification processes. The enclosed inspection report presents the results of this inspection. A final exit briefing was conducted with you and other members of your staff on October 16, 2014.

The enclosed inspection report discusses one finding that was preliminarily determined to be White, having low to moderate safety significance. The finding involved the failure to properly implement high energy line break and environmental qualification design requirements. The station reconstituted the applicable harsh environment analysis, ensured all equipment subject to a harsh environment was properly qualified to perform its safety function, and implemented plant modifications that corrected all the identified deficiencies. These corrective actions were reviewed by the NRC and found acceptable prior to plant restart that occurred in December of 2013. On October 21, 2014, you informed Mr. Anton Vegel and Mr. Michael Hay of NRC, Region IV, that the Fort Calhoun Station agreed with the low to moderate risk significance (White) characterization of this finding and that you declined an opportunity to discuss this issue in a Regulatory Conference or to provide a written response.

After considering all available information, the NRC has concluded that the finding is appropriately characterized as White, having low to moderate safety significance. The NRC has also concluded that the failure to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break is a violation of NRC requirements, as cited in the attached Notice of Violation (Notice). The circumstances surrounding this violation are discussed in detail in the enclosed inspection report. In accordance with the NRC Enforcement Policy, the Notice is considered an escalated enforcement action because it is associated with a White finding.

The NRC has concluded that the information regarding the reason for the violation, the corrective actions implemented to correct the violation and prevent recurrence, and the date when full compliance was achieved was obtained by the NRC during our inspection activities and detailed in the enclosed inspection report. Therefore, you are not required to respond to this letter unless the description contained in the enclosed report does not accurately reflect your corrective actions or your position. Additionally, since this issue was identified and resolved by the station during the extended shutdown, under increased NRC oversight of the Inspection Manual Chapter 0350 Process, this issue will not be used for future plant performance assessment inputs and is considered closed.

There were six NRC identified findings identified during this inspection that were determined to be of very low safety significance (Green), and involved violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest these violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. 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 Fort Calhoun Station.

If you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement, 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 Fort Calhoun Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” a copy of this letter, its enclosure, and your response, if you choose to provide one, 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/

Tony Vegel
Director, Division of Reactor Safety

Docket: 50-285
License: DPR-40

Enclosure:

1. Notice of Violation
2. NRC Inspection Report 05000285/2013018
   w/Attachments:
   1. Supplemental Information
   2. Detailed Risk Assessment

cc w/ encl: Electronic Distribution

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ADAMS ACCESSION NUMBER ML14329B361

☒ SUNSI Review By: MCH		☒ Non-Sensitive ☐ Sensitive		☒ Publicly Available ☐ Non-Publicly Available		
OFFICE	SRI:DRP/C	BC:DRP/F	C:ORA/ACES	SRA	DD:DRS	
NAME	JJosey/dll	MHay	RBrowder	DLoveless	AVegel	
SIGNATURE	/RA/	/RA/	/RA/	/RA/	/RA/	
DATE	11/13/14	11/18/14	11/17/14	11/18/14	11/25/14	

NOTICE OF VIOLATION

Omaha Public Power District (OPPD)
Fort Calhoun Station
EA-14-187

Docket No. 50-285
License No. DPR-40

During a U.S. Nuclear Regulatory Commission (NRC) inspection conducted from July 8, 2013, through October 15, 2014, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that, "measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structure, systems and components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions."
>
> Contrary to the above, from initial construction through October 2013, the licensee failed to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structure, systems and components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions.
>
> Specifically, the licensee failed to fully incorporate applicable design requirements to ensure that components subjected to a harsh environment maintained the capability to shut down the reactor and maintain it in a safe shutdown condition following a postulated high energy line break. This deficiency adversely affected a number of systems and components required for safe shutdown including auxiliary feedwater, charging, containment isolation, containment cooling, and shutdown cooling.

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

The NRC has concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence, and the date when full compliance will be achieved was obtained by the NRC during our inspection activities and discussed in the enclosed report. However, you are required to submit a written statement or explanation pursuant to 10 CFR 2.201 if the description therein does not accurately reflect your corrective actions or your position. In that case, or if you choose to respond, clearly mark your response as a "Reply to a Notice of Violation," include the EA number, and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region IV, and a copy to the NRC Resident Inspector at the Fort Calhoun facility, within 30 days of the date of the letter transmitting this Notice of Violation (Notice).

If you choose to respond, your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. Therefore, to the extent possible, the response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information).

Dated this 25th day of November 2014.

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	05000285
License:	DPR-40
Report:	05000285/2013018
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	9610 Power Lane Blair, NE 68008
Dates:	July 8, 2013 through October 15, 2014
Inspectors:	J. Josey, Senior Resident Inspector, Region IV T. Lightly, Project Engineer, Region II C. Smith, Project Engineer, Region IV J. Wingebach, Resident Inspector, Region IV
Accompanying Personnel	N. Patel, Electrical Contractor, Beckman and Associates
Approved By:	Tony Vegel, Director Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000285/2013018; 07/08/2013 – 10/15/2014; Fort Calhoun Station, Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs or One Red Input.

The report covered a fifteen month period of inspection by an Inspection Manual Chapter 0350 inspection team. One White and six Green, non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The cross-cutting aspect is determined using Inspection Manual Chapter 0310, "Components Within the Cross Cutting Areas." Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. 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.

Cornerstone: Mitigating Systems

- White. The team identified a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structure, systems and components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from initial construction through October 2013, the licensee failed to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break. The licensee addressed this deficiency by reconstituting the design analysis associated with the high energy line break and environmental qualification programs, receiving a change to the facilities licensing basis, and implementing plant modifications. This issue was entered into the licensee's corrective action program as Condition Report CR 2013-2857.

  The failure to ensure that design requirements were correctly translated into installed plant equipment was a performance deficiency. This performance deficiency was more than minor, and therefore a finding, because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee's failure to translate the design requirements into installed plant equipment resulted in a condition where structures, systems, and components necessary to mitigate the effects of a high energy line break may not have functioned as required. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because it was a deficiency affecting the design and qualification of a mitigating structure, system, or component that resulted in a loss of operability or functionality and represented a loss of system and/or function.

The Region IV senior reactor analyst performed a detailed risk evaluation in accordance with Appendix A, Section 6.0, “Detailed Risk Evaluation.” The detailed risk evaluation concluded the finding was best characterized as having low to moderate safety significance (White). The minimum calculated change in core damage frequency of 4.1×10^{-6} was dominated by a reactor coolant pump seal cooler loss of coolant accident followed by the failure of four containment isolation valves that were not properly qualified for a harsh environment. The upper bound was shown quantitatively and/or qualitatively to be less than 1.0×10^{-5}. The analyst determined that the finding did not affect the external events initiator risk and would not involve a significant increase in the risk of a large early release of radiation.

The team determined that this finding does not have a cross-cutting aspect because the most significant contributor of this finding would have occurred more than three years ago, and therefore, does not reflect current licensee performance. (Section 4OA4.1)

- <u>Green</u>. The team identified two examples of a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” associated with non-conservative errors identified in station calculations. Specifically, the licensee failed to use the yield strength for the most limiting type steel installed in the facility when evaluating changes to the chemical and volume control system, and failed to ensure that the acceptance criteria used for seismic anchors and supports verified that they were within the design requirements. The licensee performed an operability determination for the affected areas that established a reasonable expectation for operability pending final resolution of the problems. This issue was entered into the licensee’s corrective action program as Condition Report CR 2013-2857.

  The use of non-conservative values in station design analyses is a performance deficiency. This performance deficiency was more than minor, and therefore a finding, because it is associated with the design control attribute of the Mitigating Systems Cornerstone and affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee’s use of non-conservative yield strength to analyze the pipe break loads during a high energy line break resulted in a condition where structures, systems, and components necessary to mitigate the effects of a high energy pipe break may not have functioned as required. Additionally, the failure to use appropriate acceptance criteria resulted in a condition where structures, systems and components may not have functioned as designed during a seismic event. Using Inspection Manual Chapter 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 2, “Mitigating Systems Screening Questions,” dated July 1, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The finding has a cross-cutting aspect in the area of human performance associated with the resources component because the licensee failed to maintain long term plant safety by maintenance of design margins. Specifically, Calculation FC 07885 failed to use the most limiting yield strength when determining potential pipe break loads which resulted in a reduction of design margin [H.2(a)]. (Section 4OA4.2)

- Green. The team identified three examples of a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVII, "Quality Assurance Records," associated with the licensee's failure to furnish evidence of an activity affecting quality. Specifically, the licensee failed to maintain records demonstrating that: the temperature limits for structural concrete in the Auxiliary building would not be exceeded during a high energy line break event, that the predicted flood level in Room 81 during a high energy line break event would not affect required equipment, and that electrical splices inside of the containment were installed in accordance with the plant and the vendor installation instructions. The licensee performed an operability determination for the deficiencies that established a reasonable expectation for operability pending final resolution of the problems. The licensee entered these deficiencies into their corrective action program for resolution as Condition Reports CR 2013-22556, and CR 2013-12359.

  The licensee's failure to furnish evidence of completing analyses or maintaining records for the flood level in Room 81 during a high energy line break event, the structural concrete temperatures in the Auxiliary building, and electrical splice installations, is a performance deficiency. This 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 Systems Cornerstone, and affected the associated cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using Inspection Manual Chapter 0609, Appendix A, "Initial Screening and Characterization of Findings," dated July 1, 2012, the inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its technical specification allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The team determined that this finding does not have a cross-cutting aspect because the most significant contributor of this finding would have occurred more than three years ago, and therefore, does not reflect current licensee performance. (Section 4OA4.3)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," associated with the licensee's failure to adequately evaluate and take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 of the Auxiliary building. Specifically, the team could not locate the analyses for water level in Room 81 following a high energy line break in the room. This deficiency had previously been identified by the licensee and entered into its corrective action program, however, it was improperly closed without completing the analysis. The licensee performed operability assessments for the affected areas that established a reasonable expectation for operability pending final resolution of the problems. The licensee entered this deficiency into their corrective action program for resolution as Condition Report CR 2013-11831.

  The licensee's failure to adequately evaluate and take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 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 affected the associated objective to ensure availability, reliability, and capability of systems that responds to initiating events to prevent undesirable consequences. Specifically, the licensee failed to take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 of the Auxiliary building. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The finding has a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee failed to thoroughly evaluate problems such that the resolutions address the causes [P.1(c)].
  (Section 4OA4.4)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the failure to use conservative inputs. Specifically, the licensee failed to verify that all inputs used in the thermal lag analysis for the environmental qualification program were representative of the most limiting condition. The licensee performed an operability determination for the affected areas that established a reasonable expectation for operability pending resolution of the problems. The licensee entered this deficiency into their corrective action program for resolution as Condition Report CR 2013-14504, and CR 2013-14168.

The failure to verify that all inputs used in the thermal lag analysis for the environmental qualification program were representative of the most limiting condition 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency called into question the availability and reliability of components required to mitigate the effects of a high energy line break. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The team determined this finding has a cross-cutting aspect in the area of human performance associated with the decision-making component involving the failure to use conservative assumptions in decision-making and adopt a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate it is unsafe in order to disapprove the action [H.1(b)]. (Section 4OA4.5)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to maintain design control of the auxiliary feedwater system. Specifically, the licensee implemented a modification to the facility that placed vent holes in the steam supply line guard piping for the steam driven auxiliary feedwater pump which were located below the evaluated flood height in Room 81 and potentially rendered the pump inoperable. The licensee implemented a facility modification to protect the vent holes from water intrusion. The licensee entered this deficiency into their corrective action program for resolution as Condition Reports CR 2013-18308 and CR 2013-18605.

  The failure to ensure that design requirements were correctly translated into installed plant equipment 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee's failure to translate the design requirements into installed plant equipment resulted in a condition where the steam driven auxiliary feedwater pump may not have been able to perform its specified safety function. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because the turbine driven auxiliary feedwater pump was inoperable for longer than the technical specification allowed outage time. A regional senior reactor analyst performed a detailed risk evaluation and determined this finding to be of very low safety significance (Green) because the bounding change to the core damage frequency was approximately 1.2E-9/year. The dominant core damage sequences included feedwater and main steam line breaks with the consequential failure of the turbine driven auxiliary feedwater pump combined with other random failures of Train A and B equipment trains. Equipment that helped mitigate the risk included the diesel driven and motor-driven auxiliary feedwater pumps, which remained functional for the vast majority of sequences. This finding has a cross-cutting aspect in the area of human performance associated with the decision-making component because the licensee failed to use conservative assumptions in decision-making and adopt a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate it is unsafe in order to disapprove the action [H.1(b)]. (Section 4OA4.6)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to maintain design control of the auxiliary feedwater system. Specifically, the licensee implemented a modification to the facility that involved the installation of flood barriers surrounding the guard pipes and portions of the steam driven auxiliary feedwater pump steam supply lines that are below the evaluated flood height in Room 81. This modification would have acted like a catch basin and potentially caused the steam driven auxiliary feedwater pump (FW-10) to be inoperable during a high energy line break event. The licensee implemented a facility modification to protect the steam supply piping and vent holes from water intrusion. The licensee entered this deficiency into their corrective action program for resolution as Condition Report CR 2013-22770.

  The failure to maintain design control of the auxiliary feedwater system 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the flood barrier installed only protected the FW-10 steam supply from flood waters rising from the floor; however, this water is postulated from a high energy line break, which would both spill onto the floor and spray into Room 81 without regard for direction. This resulted in a condition where the steam driven auxiliary feedwater pump may not have been able to perform its specified safety function. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because the turbine driven auxiliary feedwater pump was inoperable for longer than the technical specification allowed outage time. A regional senior reactor analyst performed a detailed risk evaluation and determined that the finding was of very low safety significance (Green) because the bounding change to the core damage frequency was approximately 1.2E-9/year. The dominant core damage sequences included feedwater and main steam line breaks with the consequential failure of the turbine driven auxiliary feedwater pump combined with other random failures of Train A and B equipment trains. Equipment that helped mitigate the risk included the diesel driven and motor-driven auxiliary feedwater pumps, which remained functional for the vast majority of sequences. The finding was determined to have a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action component because the licensee did not take appropriate corrective actions to address safety issues, in that, an additional modification was required to protect the FW-10 steam supply from the effects of a high energy line crack or break [P.1(d)]. (Section 4OA4.7)

REPORT DETAILS

4. OTHER ACTIVITIES

4OA4 IMC 0350 Inspection Activities (92702)

The inspection team conducted NRC Inspection Manual Chapter 0350 inspection activities, which include follow-up on the Restart Checklist contained in Confirmatory Action Letter (CAL) EA-13-020 issued February 26, 2013. The purpose of this inspection was to perform an assessment of the causes of the performance decline at Fort Calhoun Station (FCS), to assess whether planned corrective actions are sufficient to address the root causes and contributing causes and to prevent their recurrence, and to verify that adequate qualitative or quantitative measures for determining the effectiveness of the corrective actions are in place. These assessments were used by the NRC to independently verify that plant personnel, equipment, and processes were ready to support the safe restart and continued safe operation of the Fort Calhoun Station that occurred in December 2013.

The team used the criteria described in baseline and supplemental inspection procedures, various programmatic NRC inspection procedures, and Inspection Manual Chapter 0350 to assess Omaha Public Power District's (the licensee) performance and progress in implementing its performance improvement initiatives. The team performed on-site and in-office activities, which are described in more detail in the following sections of this report. This report covers inspection activities from July 8, 2013 through October 15, 2014. Specific documents reviewed during this inspection are listed in the attachment.

The following inspection scope, observations and findings, and assessments, are documented by Confirmatory Action Letter Restart Checklist (CL) item number.

1. Adequacy of Significant Programs and Processes

Section 3 of the Restart Checklist addressed major programs and processes in place at the Fort Calhoun Station. Section 3 reviews also included an assessment of how the licensee addressed the NRC Inspection Procedure 95003 key attributes as described in Section 5.

<u>Item 3.b.2: High Energy Line Break Program and Equipment Qualifications</u>

(1) Inspection Scope

a. The team independently assessed the licensee's actions associated with reconstitution of the high energy line break and electrical equipment qualification programs. Specifically, the team reviewed the causal analyses, reconstituted calculations, and supporting documents to ensure the plant was within the license and design basis for high energy line break effects. (CL Items 3.b.2)

b. Open items (Licensee Event Reports) related to the electrical equipment qualification and high energy line break programs were reviewed by the team. The team verified the adequacy of the licensee's causal analyses and extent of condition evaluations. In addition, the team verified that adequate corrective actions were identified associated with the licensee's root and contributing causes and extent of condition evaluations, and that, implementation of these corrective actions are either implemented or appropriately scheduled for implementation.

(2) Observations and Findings

a. <u>High Energy Line Break Reconstitution</u>

A previous NRC team inspection, NRC Inspection Report 05000285/2013008, noted that while the analysis associated with the licensee's high energy line break reconstitution program appeared to be adequate, and when all of the proposed modifications were completed should serve to demonstrate regulatory compliance, the licensee had not adequately determined the cause of the electrical equipment qualification and high energy line break program's deficiencies and implement corrective actions to prevent recurrence. The team also noted that the licensee's equipment qualification program was not ready for inspection.

This NRC inspection performed an in-depth assessment of the facilities actions associated with reconstitution of the high energy line break and equipment qualification programs, and the associated design changes and modifications.

<u>Determine that the problem was evaluated using a systematic methodology to identify the root and contributing causes</u>.

The team determined that the licensee evaluated the identified issues using a systematic methodology to identify the root and contributing causes.

Root Cause Analysis 2013-01796 employed the use of event and causal factor charting, barrier analysis, and comparative timeline. The licensee identified the following as the root cause for why code requirements for CVCS piping were exceeded:

FCS construction project management failed to ensure that initial construction procedures for design and installation of small bore piping systems and supports specified analyses that put FCS in full compliance with USAS B31.7.

The licensee's root cause analysis also identified the following contributing causes:

CC-1: Fort Calhoun Station did not recognize the value of detailed and comprehensive small bore piping and support analyses when the generic methodology was repeatedly challenged from initial construction to 1993.

CC-2: From 1993 to present, Fort Calhoun Station performed inadequate engineering analyses to demonstrate small bore piping and supports meet code compliance. These deficiencies were related to engineering judgments.

CC-3: Fort Calhoun Station did not effectively use the corrective action program to resolve issues identified with the station small bore piping.

The team determined that these root and contributing causes reasonably explain why the code requirements for CVCS piping were exceeded. Specifically the team determined that the corrective actions to replace all of the CVCS piping with butt welded piping and completing piping stress and thermal fatigue analysis would be adequate to address this problem.

Root Cause Analysis 2013-2857 stated that the analytical methods used during the investigation included event and causal factor charting and fault tree analysis. The licensee identified the following as the root causes and contributing cause for the electrical equipment qualification, and high energy line break programs deficiencies.

RC-1: Fort Calhoun Station's response to IE Bulletin 79-01B made inaccurate and simplifying assumptions, without supporting documentation, that compromised the validity and scope of the electrical equipment qualification program, ultimately resulting in the program being non-compliant with 10 CFR 50.49.

RC-2: The electrical equipment qualification program has unique processes that are not integrated into the engineering change process; creating an unnecessary burden on the electrical equipment qualification coordinator, and affecting the sustainability of the electrical equipment qualification program.

CC-1: Engineering has not effectively resolved items identified in the corrective action program.

The team determined that these root and contributing causes reasonably explain why the electrical equipment qualification and high energy line break programs were deficient. The team identified a finding, VIO 05000285/2013018-01, "Failure to Correctly Translate Design Requirements into Installed Plant Configuration," which is further discussed in Section 5 of this report.

Root Cause Analysis 2012-07724 employed the use of event and causal factor charting, barrier analysis, cause and effect tree and comparative timeline. The licensee identified the following as the root and contributing causes for why code requirements for thermal fatigue for the chemical and volume control system piping were exceeded:

RC: OPPD Engineering Personnel did not understand the significance of thermal fatigue analysis requirements in draft USAS B31.7, overly relied on Architectural Engineer guidance, and did not have a process in place to prevent the original chemical and volume control system piping design from excluding the cyclical analysis requirements of USAS B31.7.

CC-1: Fort Calhoun Station Calculation FC06484, Resolution of Design Basis Open Items 122 and 145 prescribed that Class I pressurizer spray piping be a representative subsystem for the Class I chemical and volume control system piping.

CC-2: Fort Calhoun Station personnel adopted an approach to credit current calculations, whenever possible, to close design basis document (DBD) action items.

CC-3: PED-QP-3, Calculation Preparation, Review and Approval did not require verification of the vendor calculation assumptions, inputs and conclusions in Fort Calhoun's Station Calculation FC06484.

The team determined that these root and contributing causes reasonably explain why the thermal fatigue code requirements for chemical and volume control system piping were exceeded. Specifically, the team determined that the corrective actions to replace all of the CVCS piping with butt welded piping and completing piping stress and thermal fatigue analysis would be adequate to address this problem.

Determine that the root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.

The team determined that the root cause analyses were conducted to a level of detail commensurate with the significance of the problems. Specifically, as discussed above, the licensee conducted the evaluations not only by using event and causal factor charting, barrier analysis, and comparative timeline, but also by conducting interviews, and reviewing documents. The licensee's root cause analyses techniques were generally thorough and identified the root and contributing causes of deficiencies.

Determine that the root cause evaluation included a consideration of prior occurrences of the problem and knowledge of prior operating experience.

The team determined that the root cause analyses included evaluations of both internal and industry operating experience. The team determined that the licensee's evaluations of industry operating experience provided sufficient detail such that general conclusions could be established regarding any similarities.

Determine that the root cause evaluation addressed the extent of condition and the extent of cause of the problem.

For extent of condition, the licensee evaluated the extent to which the actual condition exists with other plant equipment. The licensee's analyses used the same-same, same-similar, similar-same, and similar-similar evaluation method.

For Root Cause Analysis 2013-01796 the licensee concluded that an extent of condition does exist for small bore safety-related piping supports. However, the licensee did not include large bore piping in the extent of condition. The team questioned if elimination of large bore piping was appropriate given the non-conservative engineering judgment and assumptions documented in other piping stress calculations and thermal stress evaluations. The team identified a finding, NCV 05000285/2013018-02, "Use of Non-conservative Values in Design Analyses," which is further discussed in Section 5 of this report.

For Root Cause Analysis 2013-02857 the licensee concluded that an extent of condition exists for programs that do not implement their individual requirements.

For Root Cause Analysis 2013-07724 the licensee concluded that an extent of condition does exist for the following Class I piping systems that do not have a thermal fatigue analysis of record:

- Primary Plant Sampling
- Reactor Coolant Gas Vent
- Reactor Coolant
- Safety Injection
- Waste Disposal

For extent of cause, the licensee reviewed the root cause of an identified problem to determine where it may have impacted other plant processes, equipment, or human performance.

For Root Cause Analysis 2013-01796, the licensee determined that an extent of cause does exist related to structures, systems and components, and processes that could have been adversely affected by piping designs, and the licensee is not in full compliance to the code of record. Identified gaps between the licensing basis and full code compliance were one of the focus areas in the design basis root cause analysis. The following root cause analyses were completed to address licensing and design basis: CR 2012-08125, "Engineering Design / Configuration Control (FPD)", CR 2012-19723, "Failure to Maintain Design Basis Documents", and CR 2013-05570, "Engineering Design and Licensing."

For Root Cause Analysis 2013-02857, the licensee determined that an extent of cause did not exist for RC-1 or RC-2.

For Root Cause Analysis 2013-01796, the licensee determined that an extent of cause does exist related to structures, systems and components, and processes that could have been adversely affected by piping designs. The following root cause analyses were completed to address licensing and design basis: CR 2012-08125, "Engineering Design / Configuration Control (FPD)", CR 2012-19723, "Failure to Maintain Design Basis Documents", and CR 2013-05570, "Engineering Design and Licensing." The licensee's evaluation determined a revision of PED-GEI-3 is recommended to incorporate thermal fatigue considerations for Class I piping, and the review of the code reconciliation between USAS B31.7 and ASME III (CA-6) for other areas if CVCS did not find any additional Class 1 piping that did not comply with USAS B31.7. The licensee determined that an operability determination was required for the following systems prior to plant heat up:

- Primary Plant Sampling
- Reactor Coolant Gas Vent
- Reactor Coolant
- Safety Injection
- Waste Disposal

The team determined that open questions relating to the reclassification of safety related piping in the 1990s are currently being reviewed. The team determined that the licensee's corrective actions would only be effective once verification of the Class I and II piping is completed.

Determine that the root cause, extent of condition, and extent of cause evaluations appropriately considered the safety culture components as described in IMC 0310.

The team determined that the licensee's root cause, extent of condition, and extent of cause evaluations appropriately considered the safety culture components as described in Inspection Manual Chapter 0310. Specifically, the licensee documented their consideration of the Inspection Manual Chapter 0310 cross-cutting aspects in Attachment 6 of RCA 2013-01796, Attachment 12 of RCA 2013-02857, and Attachment 7 of RCA 2012-07724.

For Root Cause Analysis 2013-02857, the licensee identified several cross-cutting aspects in the areas of human performance, problem identification and resolution, and other components.

For Root Cause Analysis 2013-01796, the final evaluation concluded that the safety culture attributes were not applicable.

For Root Cause Analysis 2012-07724, the final evaluation concluded that the safety culture attributes were not applicable.

The team determined that the licensee's assessment appropriately considered the safety culture components described in IMC 0310.

Determine that appropriate corrective actions are specified for each root and contributing cause.

The team reviewed the licensee's corrective actions for each of the identified root and contributing causes. The team found that the corrective actions addressed the root and contributing causes.

For Root Cause Analyses 2013-01796 and 2012-07724, the team noted that the corrective actions focused primarily on engineering procedures, and updating the licensing basis to bring it into compliance with code requirements. The team noted that a lot of the corrective actions have been rescheduled. In addition, questions related to the reclassification of safety related piping in the 1990s are currently being reviewed. The team determined that the licensee's corrective actions would only be effective once verification of the Class I and II piping is completed.

The team determined that the licensee's efforts to reconstitute the high energy line break and electrical equipment qualification programs had missed opportunities to identify nonconformances and the use of non-conservative calculation inputs. Specifically, during the inspection the team identified the following issues:

- NCV 05000285/2013018-03, "Failure to Furnish Evidence of Activities Affecting Quality"
- NCV 05000285/2013018-04, "Failure to Promptly Identify and Correct Inadequate Internal Flooding Analysis"

- NCV 05000285/2013018-05, “Use of Non-Conservative Inputs in Thermal Lag Analyses”

- NCV 05000285/2013018-06, “Failure to Recognize Adverse Design Changes”

These findings are further discussed in Section 5 of this report.

Determine that a schedule has been established for implementing and completing the corrective actions.

The team determined that a schedule has been established for implementing and completing the corrective actions. The team found that corrective actions to prevent recurrence had been scheduled or implemented which included procedures changes and implementation of necessary training for engineers. Additionally, corrective actions to address the contributing causes had been scheduled. The team determined that that licensee’s schedule for implementing corrective actions appeared to be commensurate with the significance of the issues they are addressing.

Determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

The team determined that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

For Root Cause Analysis 2013-01796, the licensee established, in part, an effectiveness review consisting of modification reviews of design products completed after implementation of the corrective actions to prevent recurrence to determine if modification packages included pipe stress and piping support analysis.

For Root Cause Analysis 2013—2857, the licensee established, in part, self-assessment requirements for the electrical equipment qualification program, and completed work order reviews for environmentally qualified equipment to ensure that maintenance did not invalidate equipment qualification.

For Root Cause Analyses 2012-07724, the licensee established, in part, an effectiveness review consisting of modification reviews of design products completed after implementation of the corrective actions to prevent recurrence to determine if modification packages included thermal fatigue analysis and piping support analysis. The licensee also implemented interim actions for the corrective actions to prevent recurrence that would not be completed until 2018. The interim actions will review design basis reconstitution milestones to ensure the licensee is on track for completing corrective actions to prevent recurrence. The interim effectiveness actions also will review the procedure and training changes to ensure they are in compliance with current guidelines.

The team determined that the licensee’s effectiveness criteria did meet the criteria established in Procedure FCSG 24-7, “Effectiveness Review of Corrective Actions to

Prevent Recurrence (CAPRs)," Revision 1, in that the effectiveness review specified specific success criteria.

b. The NRC reviewed the licensee's causal analyses, corrective actions, and extent of condition associated with Licensee Event Reports 2012-017, "Containment Valve Actuators Design Temperature Ratings Below those Required for Design Basis Accidents," 2013-011, "Inadequate Design for High Energy Line Break in Rooms 13 and 19 of the Auxiliary building," 2013-015, "Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82," and 2013-016, "Reporting of Additional High Energy Line Break Concerns." In addition, the team verified that adequate corrective actions were identified associated with the causes and extent of condition evaluations and that implementation of these corrective actions were either implemented or appropriately scheduled for implementation.

(3) Assessment

a. The NRC performed an independent assessment of the licensee's actions associated with reconstitution of the high energy line break and electrical equipment qualification programs. Based on these reviews, the team concluded that the licensee's analyses, design changes, and modifications associated with the reconstituted programs were adequate and demonstrated regulatory compliance.

The team concluded that the licensee continues to demonstrate weaknesses with regard to identifying nonconforming conditions, and recognizing the use of non-conservative inputs into design calculations. The team noted that these areas are being addressed by the licensee under long term corrective actions that will be reviewed by the NRC during future inspections.

The following Restart Checklist Items were closed:

3.b.2.1 Licensee assessment of high energy line break program and equipment qualifications

3.b.2.2 Adequacy of extent of condition and extent of causes

3.b.2.3 Adequacy of corrective actions

4.5.1.8 Complete EEQ Harsh Environment analysis for Room 13 crack in Steam Generator Blowdown system

4.5.1.9 Develop plan to address Room 13 EEQ harsh environment qualification of electrical equipment

4.5.1.10 Initiate actions to resolve Room 13 EEQ harsh environment qualification of equipment which must be addressed prior to leaving cold shutdown

4.5.1.11 Resolve Room 13 EEQ harsh environment qualification of equipment which must be addressed prior to leaving cold shutdown

4.5.1.12 Perform analysis to address HCV-1385/1386 Main Steam Line Break/Feedwater isolation concern (CR 2011-6757)

4.5.1.13 Implement resolution of HCV-1385/1386 Main Steam Line Break/Feedwater isolation concern

b. Licensee Event Reports 2012-017-2, “Containment Valve Actuators Design Temperature Ratings Below those Required for Design Basis Accidents,” 2013-011-0, “Inadequate Design for High Energy Line Break in Rooms 13 and 19 of the Auxiliary building,” 2013-015-1, “Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82,” and 2013-016-0, “Reporting of Additional High Energy Line Break Concerns,” are closed.

Item 3.c: Design Changes and Modifications

(1) Inspection Scope

A previous NRC team inspection, NRC Inspection Report 05000285/2013008, had performed a limited scope review of Modification EC 53202, “Modify Piping and Supports for FW-10 MS Supply for HELB Concerns,” Revision 0, looking only at the modification package, since the in-plant modification was not completed at the time of this inspection. The team determined that it appeared that the licensee had appropriately evaluated the modification package, but pending installation and acceptance of this modification and follow-up assessment by the NRC, Restart Checklist Item 3.c would remain open.

This NRC inspection team performed an in-depth assessment of the licensee’s actions that were taken to address design changes and modifications to the facility. These items are listed in the Fort Calhoun Station Flooding and Recovery Action Plan, Revision 3, dated July 9, 2012. Specifically, the team assessed the effectiveness of the licensee’s implementation of changes to facility structures, systems, and components, evaluations required by 10 CFR 50.59, and the Updated Safety Analysis Report, to provide assurance that changes implemented by the licensee have been appropriately implemented. (CL Item 3.c)

(2) Observations and Findings

The team performed an independent review of the modifications implemented by the licensee to correct deficiencies identified during the reconstitution of the high energy line break and electrical equipment qualification programs. During this review, the team assessed the effectiveness of the licensee’s process for preparing the modifications; the associated evaluations required by 10 CFR 50.59, the implementation of the modifications, and how required updates to the Updated Safety Analysis Report were identified for incorporation.

The team determined that during the implementation of Modification EC 53202, the licensee failed to identify non-conformances and the use of non-conservative calculation inputs. Specifically, during the inspection the team identified the following issue:

- NCV 05000285/2013018-07, “Failure to Maintain Design Control of the Auxiliary Feedwater System”

This finding is further discussed in Section 4 of this report.

(3) Assessment Results

The team concluded, based on their reviews of the licensee's modifications, and actions taken to address the identified deficiencies, that this area had been adequately addressed by the licensee.

The following Restart Checklist Items were closed:

4.5.1.1	Review of EC 53202; FW-10 Steam Line HELB Modification
4.5.1.2	Final SMART Review of EC 53202; FW-10 Steam Line HELB Modification
4.5.1.3	Plant Review Committee review of EC 53202; FW-10 Steam Line HELB Modification
4.5.1.4	Develop Construction Work Orders for EC 53202; FW-10 Steam Line HELB Modification
4.5.1.5	Complete installation of EC 53202; FW-10 Steam Line HELB Modification
4.5.1.6	Prepare EC 52662; Add a new Pipe Support on the SGBD vertical line above FW-1020
4.5.1.7	Install EC 52662; Add a new Pipe Support on the SGBD vertical line above FW-1020

5. Specific Issues Identified During This Inspection

1. Failure to Correctly Translate Design Requirements into Installed Plant Configuration

Introduction. The team identified a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structure, systems and components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from initial construction through October 2013, the licensee failed to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break.

Description. The team reviewed the licensee's efforts to reconstitute the station's design analyses for the high energy line break program. During this review, the team determined that the licensee had failed to ensure that design requirements were correctly translated into installed plant equipment.

On December 18, 1972, and January 22, 1973, the NRC sent letters to the licensee requesting a detailed design evaluation to substantiate that the design of the Fort Calhoun Station was adequate to withstand the effects of a postulated rupture in any high energy fluid piping systems outside the primary containment.

On March 14, 1973, the licensee submitted their response to the NRC letters referenced above. In their response, the licensee identified the essential structures and equipment required for a safe shutdown which could be damaged by a pipe rupture, and stated that the main steam and main feedwater systems had been identified as the major high energy systems which had the greatest potential to inhibit safe shutdown in the event of a postulated pipe rupture. The licensee also stated that evaluations would continue to complete the analysis of the effects of a rupture in high energy fluid piping systems. On March 15, 1973, the licensee submitted their final response to the NRC letters. In this response, the licensee identified other piping systems as non-major high energy systems, and determined that they either had no effect on safe shutdown capability, or required deflector plates to be installed to prevent jet impingement on electrical cables.

On May 31, 1978, the NRC Office of Inspection and Enforcement (IE) issued IE Circular 78-08, "Environmental Qualification of Safety-Related Electrical Equipment at Nuclear Power Plants," which requested all licensees of operating plants to examine their installed safety-related electrical equipment that are required to function under postulated accident conditions. On February 8, 1979, the NRC issued IE Bulletin 79-01, which was intended to raise IE Circular 78-08 to the level of a Bulletin (i.e., action requiring a licensee response). This Bulletin required a complete re-review of the environmental qualification of safety-related electrical equipment as described in IE Circular 78-08. Subsequently, on January 14, 1980, the NRC issued IE Bulletin 79-01B which expanded the scope of IE Bulletin 79-01 and requested additional information on environmental qualification of safety-related electrical equipment at operating plants.

On March 3, 1980, the licensee submitted their response to IE Bulletin 79-01B. In this letter, the licensee stated that only the main steam and main feedwater line breaks could cause accident conditions that would challenge safety related electrical equipment. It stated that all other systems had been excluded from review because they did not affect the ability to bring the unit to safe shutdown. This response formed the licensee's basis for the station's environmental qualifications, and superseded their high energy pipe rupture response letter dated March 15, 1973.

In August 2007, the licensee initiated Condition Reports CR 2007-02715 and CR 2008-01186, to document issues with the electrical equipment qualification and high energy line break programs. As a result, the licensee performed a focused self-assessment (FSA-07-47) to evaluate the station's environmental qualification program as it relates to the industries best practices. During this assessment, the licensee identified that the station did not meet industry best practices, and the station's response to IE Bulletin 79-01B had made inaccurate simplifying assumptions with regard to high energy piping systems failures.

The licensee ultimately determined that all regulatory requirements were currently being met by the program; the issue was a failure to meet industry best practices. The licensee subsequently performed a root cause analysis to determine why the station's electrical equipment qualification program (this includes the high energy line break program) did not meet industry standards. The licensee determined the root cause of this issue to be, organizational changes caused a loss of knowledge transfer and documentation which was exacerbated by; the historical design basis documents not always being retrievable and auditable, and there being no rigorous review of the environmental qualification program since the early 1990s. The licensee's corrective actions focused on complying with industry best practices.

The team noted that the licensee continued to document programmatic weaknesses and documentation deficiencies associated with the electrical equipment qualification and high energy line break programs in the corrective action program. As these issues were resolved, the licensee discovered additional issues with the programs, including lack of design bases analyses, and equipment configuration qualification issues. Based on this, the licensee had recognized the need to reconstitute the electrical equipment qualification and high energy line break programs, and initiated the electrical equipment qualification program corrective action project in 2008. The team noted that this project was being performed outside of the station's corrective action program. As a result of this observation by the team, the licensee initiated Condition Report CR 2013-2857 to evaluate the cause of the programmatic breakdown and correct this issue.

The team reviewed the licensee's root cause analyses and noted that the licensee had determined that the causes of the programmatic break downs to be:

> RC-1: Fort Calhoun Station's response to IE Bulletin 79-01B made inaccurate and simplifying assumptions, without supporting documentation, that compromised the validity and scope of the electrical equipment qualification program, ultimately resulting in the program being non-compliant with 10 CFR 50.49.
>
> RC-2: The electrical equipment qualification program has unique processes that are not integrated into the engineering change process; creating an unnecessary burden on the electrical equipment qualification coordinator, and affecting the sustainability of the electrical equipment qualification program.

The team determined that this issue had resulted in a condition where twenty four areas in the facility that contained high energy piping had not been evaluated for the effects of a rupture in this piping to ensure that the structures, systems, and components necessary to bring the reactor to safe shutdown following a high energy line break were qualified to be able to perform their specified safety function. Specifically, multiple system components affecting:

- auxiliary feedwater
- charging
- containment isolation
- containment cooling; and
- shutdown cooling

may not have functioned as designed following a high energy line break. A detailed listing of affected equipment is contained in Attachment 3 of this document.

The licensee addressed this deficiency by reconstituting the design analysis associated with the programs, receiving a change to the facilities licensing basis, and implementing plant modifications.

Analysis. The failure to ensure that design requirements were correctly translated into installed plant equipment was a performance deficiency. This 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee's failure to translate the design requirements into installed plant equipment resulted in a condition where structures, systems, and components necessary to mitigate the effects of a high energy pipe break may not have functioned as required. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because it was a deficiency affecting the design and qualification of a mitigating structure, system, or component that resulted in a loss of operability or functionality and represented a loss of system and/or function.

The Region IV senior reactor analyst performed a detailed risk evaluation in accordance with Appendix A, Section 6.0, "Detailed Risk Evaluation." The evaluation concluded the finding was best characterized as having low to moderate safety significance (White). The minimum calculated change in core damage frequency of 4.1×10^{-6} was dominated by a reactor coolant pump seal cooler loss of coolant accident followed by the failure of four isolation valves containing inappropriate elastomers. The upper bound was shown quantitatively and/or qualitatively to be less than 1.0×10^{-5}. The analyst determined that the finding did not affect the external events initiator risk and that the finding would not involve a significant increase in the risk of a large early release of radiation.

The team determined that this finding does not have a cross-cutting aspect because the most significant contributor of this finding would have occurred more than three years ago, and therefore, does not reflect current licensee performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that, "measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions." Contrary to the above, measures established by the licensee did not assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from initial construction through October 2013, the licensee failed to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break. The licensee addressed this deficiency by implementing plant modifications and receiving a change to the facilities licensing basis. This finding is associated with a Notice of Violation attached to this report: VIO 05000285/2013018-01, "Failure to Correctly Translate Design Requirements into Installed Plant Configuration."

2. Use of Non-conservative Values in Design Analyses

Introduction. The team identified two examples of a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with non-conservative errors identified in station calculations.

Description. The team identified two examples where the licensee had non-conservative inputs used in station design analyses.

Example 1: The team reviewed Calculation FC07885, "Stress Analysis for Small Bore Piping on Isometric CH4106 High Energy Line Break Assessment," which compared ASME Section III requirements to the requirements of USAS B31.7 for the chemical volume control system small bore piping and supports. This analysis was performed to ensure the piping was capable of withstanding a high energy line break event. During their review the team determined that the calculation did not use the most conservative yield strength between USAS B31.7 and ASME Section III. Specifically, Calculation FC07885 identified that steel type SA312 TP304 had a yield strength (S_y) of 18,900 lbs/in^2 and type SA376 TP316 had a yield strength (S_y) of 20,900lbs/in^2. However, the licensee had used the less conservative yield strength of 20,900 lbs/in^2 to calculate potential pipe break locations. The team determined that this was non-conservative and informed the licensee of their concerns.

The licensee initiated Condition Report CR 2013-13743 to capture this issue in the station's corrective action program. This does not represent an immediate safety concern because the licensee performed an operability determination for the affected areas, which established a reasonable expectation for operability pending resolution of the identified issue.

Example 2: The team reviewed Calculation FC07234, "Evaluation of Shutdown Cooling Mode Temperature and Pressure increase on the SI System Piping and Pipe Supports," Revision 0, which had been prepared to analyze the shutdown cooling system piping and supports because of changes to the entry conditions. During this review, the team determined that the calculation contained the following non-conservative errors:

- The analyses identified an instance where an analyzed piping node exceeded pipe allowable stresses. However, the licensee had instituted non-conservative acceptance criteria that allowed this node to be accepted. Specifically, a finite analysis was used to lower the stress intensification factor for a pipe tee in subsystem SI-191A. This was not fully bounded by the design specifications of the system.

- The calculation allowed the use of piping support displacement criteria which was contrary to the facilities current licensing basis. Specifically, the calculations criterion for additional evaluation for thermal and seismic anchor movements was 1/8 of an inch. However, the station's current licensing basis required that additional evaluation for seismic anchor or support movement be performed at 1/16 of an inch.

- The calculation determined that a pipe support, SIH-243, would experience uplift which would exceed the allowable stress for that support. However, this was determined to be acceptable because the load would distribute to other supports, SIH-8 and SIH-9, and would be within faulted capacities of these supports. The team determined that this was non-conservative because piping supports are required to meet stress allowables for all normal required loadings without crediting faulted load (accident) allowables.

The licensee initiated Condition Reports CR 2013-18639, CR 2013-18253, CR 2013-18086, CR 2013-14637, and CR 2013-18390 to capture these issues in the station's corrective action program. This does not represent an immediate safety concern because the licensee performed an operability determination for the affected areas, which established a reasonable expectation for operability pending resolution of the identified issues.

The team determined the cause of these issues was that the licensee had failed to recognize the use of non-conservative inputs into design analyses, which resulted in a reduction in design margin for the systems.

<u>Analysis</u>. The use of non-conservative values in station design analyses is a performance deficiency. This 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the licensee's use of non-conservative yield strength to analyze the pipe break loads during a high energy line break resulted in a condition where structures, systems, and components, necessary to mitigate the effects of a high energy pipe break, may not have functioned as required, and the failure to use the correct acceptance criteria resulted in a condition where structures, systems, and components may not have functioned as designed during a seismic event. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program.

The finding has a cross-cutting aspect in the area of human performance associated with the resources component because the licensee failed to maintain long term plant safety by maintenance of design margins. Specifically, Calculation FC 07885 failed to use the most limiting yield strength when determining potential pipe break loads which resulted in a reduction of design margin [H.2(a)].

<u>Enforcement</u>. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, 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 the above, measures established by the licensee did not assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from August 2007 through October 2013, Station

Calculations FC07234 and FC07885 contained non-conservative inputs which resulted in the analyses failing to demonstrate that design requirements were met. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as Condition Reports CR 2013-13743, CR 2013-18639, CR 2013-18253, CR 2013-18086, CR 2013-14637, and CR 2013-18390. (NCV 05000285/2013018-02, "Use of Non-conservative Values in Design Analyses")

3. Failure to Furnish Evidence of Activities Affecting Quality

Introduction. The team identified three examples of a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVII, "Quality Assurance Records," associated with the licensee's failure to furnish evidence of an activity affecting quality.

Description. The team identified three examples of the licensee's failure to maintain quality records.

Example 1: Guard pipes surround the steam driven auxiliary feedwater pumps (FW-10) steam supply lines and protect safety-related equipment in the event of a FW-10 steam supply line break. The guard pipes are embedded in the concrete floor of Room 81, and are therefore considered penetrations. The concrete has specific temperature limitations based upon normal operations and accident or short-term operations. The guard pipes have cooling fins to aid in dissipating heat from the steam supply lines to the environment to maintain the temperature of the concrete surrounding the guard pipes within limits.

While reviewing Engineering Change 62391, "FW-10 Steam Supply Line A and B Flood Barriers," Revision 0, the team noted that the Engineering Review Group had identified that no calculation was found for the cooling fins for guard pipes AE-31 and AE-32, but the Engineering Review Group failed to enter this deficiency into the corrective action program.

The team questioned whether the fins were adequately sized due to other modifications regarding the guard pipes. The team informed the licensee of their concerns, and the licensee initiated Condition Report CR 2013-22556 to track formal documentation of the heat transfer capability of guard pipe AE-31 and AE-32's fins. The licensee subsequently measured the concrete temperatures surrounding the guard pipes and performed an evaluation to determine whether the concrete would remain below temperature limits during accident conditions. Both the temperature measurements and evaluation determined that the concrete would remain below limits.

The team determined that sufficient records had not been maintained to furnish evidence of activities affecting quality. Specifically: (1) the licensee could not furnish a calculation that demonstrated the guard pipe fin sizing was adequate; (2) a calculation would have been required to appropriately size the fins initially; and (3) the results of the calculation directly affected the auxiliary feedwater system and the structure of the Auxiliary building.

Example 2: While reviewing the station's Environmental Qualification records the team noted that there was no documented record that demonstrated that the Raychem

Splices inside containment were installed in accordance with the specified installation instructions. The team noted that the incorrect installation of these splices could result in the ingress of the moisture into the splice which could affect the ability of the equipment to perform its specified safety functions.

The team informed the licensee of their concerns and the licensee initiated Condition Report CR 2013-14585 to capture this issue in the station's corrective action program. During subsequent reviews, the licensee determined that the these splices had been installed and inspected as part of the station's response to Information Notice 86-53, "Improper Installation of Heat Shrinkable Tubing," and the NRC had reviewed the station's response and found it acceptable. This provided a reasonable basis for operability. However, the team determined that sufficient records had not been maintained to furnish evidence of activities affecting quality.

Example 3: While reviewing Calculations EA-FC-06-032, "Environmental Parameters for Electrical Equipment Qualification," Revision 0, and FC 05291, "Aux Building Room 81 Flooding Analysis," Revision 0, the team questioned the basis of the maximum flood height used for environmental qualification of equipment in Room 81. Specifically, FC 05291 evaluated the effect of a modification that added an additional potential source of flooding to Room 81, and used as an input of 1.36 feet for the maximum flood level in the room due to a high energy line break. This was cited as coming from USAR, Appendix M, "Postulated High Energy Line Rupture Outside Containment," Revision 12, because the original analyses was unavailable. The team reviewed Appendix M and noted that there was not an analytical basis to support the determination of a flood depth of 1.36 feet. The team requested the analyses that supported this determination and the licensee was not able to locate it. The licensee initiated Condition Report CR 2013-12359 to capture this issue in the station's corrective action program.

The licensee subsequently determined that the analyses which established the flood depth in Room 81 following a high energy line break had not been maintained. The licensee performed an operability evaluation for this issue and implemented compensatory measures pending reconstitution of the analyses. The team determined that sufficient records had not been maintained to furnish evidence of activities affecting quality.

Analysis. The licensee's failure to furnish evidence of activities which affected quality was a performance deficiency. The performance deficiency is more-than-minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affected the associated cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of evidence of calculations for concrete temperatures in the Auxiliary building and the flood height in Room 81 following a high energy line break, and records which demonstrated that the Raychem Splices inside containment were installed in accordance with the specified installation instructions, represents instances where the licensee was not able to substantiate that the design of the facility was adequate following modifications. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, the team determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. This finding does not have a cross-cutting aspect because the most significant contributor of this finding, which could not be determined, would have occurred prior to three years ago, and therefore, is not representative of current licensee performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVII, Quality Assurance Records states, in part, that, "sufficient records shall be maintained to furnish evidence of activities affecting quality." Contrary to the above, the licensee failed to maintain sufficient records to furnish evidence of activities affecting quality. Specifically, prior to December 13, 2013, the licensee was unable to furnish evidence of calculations that demonstrated that the structural concrete temperatures would remain below limits, what the flood height in Room 81 following a high energy line break would be, and records which demonstrated that the Raychem Splices inside containment were installed in accordance with the specified installation instructions. Because this finding is of very low safety significance and has been entered into the corrective action program as Condition Report CR 2013-22556, the violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy:
NCV 05000285/2013018-03, "Failure to Furnish Evidence of Activities Affecting Quality."

4. Failure to Promptly Identify and Correct Inadequate Internal Flooding Analysis

Introduction. The team identified a Green, non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," associated with the licensee's failure to adequately evaluate and take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 of the Auxiliary building.

Description. While reviewing the station's high energy line break reconstitution efforts, the team noted an issue with Calculations EA-FC-06-032, "Environmental Parameters for Electrical Equipment Qualification," Revision 0, and FC 05291, "Aux Building Room 81 Flooding Analysis," Revision 0 (NCV 2013018-03). Specifically, the team could not locate the analyses for water level in Room 81 following a high energy line break in the room.

The team informed the licensee of their concern and during follow up discussions the team determined that the licensee had previously entered this issue in the station's corrective action program as Condition Report CR 2012-07534. Through subsequent review of this condition report the team determined that the action item associated with this issue, 2012-07534-002 RE, had been closed improperly without the issue being resolved. The team determined that the licensee had failed to promptly correct a condition adverse to quality.

The team informed the licensee of their concerns and the licensee initiated Condition Report CR 2013-12359 to capture this issue in the station's corrective action program. This does not represent an immediate safety concern because the licensee performed operability assessments for the affected areas, which established a reasonable expectation for operability pending resolution of the identified issue.

Analysis. The licensee's failure to adequately evaluate and take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 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 affected the associated objective to ensure availability, reliability, and capability of systems that responds to initiating events to prevent undesirable consequences. Specifically, the licensee failed to take prompt corrective actions to address an identified condition adverse to quality related to the internal flooding analysis for Room 81 of the Auxiliary building. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The finding has a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action program component because the licensee failed to thoroughly evaluate problems such that the resolutions address the causes [P.1(c)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformance's are promptly identified and corrected. Contrary to the above, the licensee failed to establish measures to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformance's were promptly identified and corrected. Specifically, from 1989 until present, the licensee failed to properly calculate the flood level in Room 81 following a high energy line break. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as Condition Report CR 2013-11831. (NCV 05000285/2013013-04, "Failure to Promptly Identify and Correct Inadequate Internal Flooding Analysis")

5. Use of Non-Conservative Inputs in Thermal Lag Analyses

Introduction. The team identified a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the failure to use conservative inputs.

Description. While reviewing Calculation FC 08060, "Thermal Lag Analysis for Equipment in Room 81 at Fort Calhoun Station," Revision 0, the team identified four instances where the licensee had failed to verify inputs used in the analysis. Specifically:

1. Emissivity values for stainless steel ranges from 0.17-0.9. However, the emissivity value used in the analysis was 0.8.

2. An assumption used in the analysis was that no equipment was within the zone of influence of jet impingement of the High Energy Line Breaks. The team walked the area down and determined that this assumption was not correct.

3. During a walkdown of Room 81, the inspector identified that there is Rockbestos cable Firewall III which was not evaluated in the thermal lag analysis.

4. The team identified that the process fluid temperature was not considered in the thermal lag analysis.

The team determined that: (1) not all of the inputs were conservative; (2) not all the assumptions used were verified; (3) not all of the equipment and components were analyzed; and (4) not all of the process fluid temperatures were considered in the thermal lag analysis.

The team informed the licensee of their concerns and the licensee initiated Condition Reports CR 2013-14504 and CR 2013-14168 to capture these issues in the station's corrective action program. This does not represent an immediate safety concern because the licensee performed an operability determination for the affected areas, which established a reasonable expectation for operability pending resolution of the identified issue.

Analyses. The failure to verify that all inputs used in the thermal lag analysis for the environmental qualification program were representative of the most limiting condition 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 affected the associated objective to ensure availability, reliability, and capability of systems that responds to initiating events to prevent undesirable consequences. Specifically, the performance deficiency called into question the availability and reliability of components required to mitigate the effects of a high energy line break. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated July 1, 2012, inspectors determined that the finding was of very low safety significance (Green) because the finding: (1) was not a deficiency affecting the design and qualification of a mitigating structure, system, or component, and did not result in a loss of operability or functionality; (2) did not represent a loss of system and/or function; (3) did not represent an actual loss of function of at least a single train for longer than its allowed outage time, or two separate safety systems out-of-service for longer than their technical specification allowed outage time; and (4) does not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours in accordance with the licensee's maintenance rule program. The team determined this finding has a cross-cutting aspect in the area of human performance associated with the decision-making component involving the failure to use conservative assumptions in decision-making and adopt a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate it is unsafe in order to disapprove the action [H.1(b)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that, "measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions." Contrary to the above, the licensee failed to establish measures which assured that applicable regulatory requirements and the design bases, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from June 12, 2012, through July 2013, the licensee failed to verify that all inputs used in the thermal lag analysis for the environmental qualification program were representative of the most limiting condition. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as Condition Reports CR 2013-14504 and CR 2013-14168. (NCV 05000285/2013018-05, "Use of Non-Conservative Inputs in Thermal Lag Analyses")

6. Failure to Recognize Adverse Design Changes

Introduction. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to maintain design control of the auxiliary feedwater system.

Description. While reviewing Engineering Change 53202, "Modify Piping and Supports for FW-10 MS Supply for HELB Concerns," Revision 0, the team identified that the licensee had added vent holes to the AE-31 and AE-32 guard pipes. The guard pipes encapsulate the steam supply lines to the turbine-driven auxiliary feedwater pump (FW-10), and were installed to contain steam in the event of a break in the supply lines. The vent holes were added to provide a relief path for this steam. However, the vent holes were located below the evaluated flood height in Room 81. Flood water, which is postulated to occur from a high energy line break in piping, such as the main steam or main feedwater systems in Room 81, could condense steam within the supply lines to FW-10, resulting in slug flow or insufficient steam quality to the turbine, rendering FW-10 inoperable.

The team informed the licensee of their concern and the licensee initiated Condition Reports CR 2013-18308 and CR 2013-18605. During an extent of condition review, the licensee identified that a portion of the FW-10 steam supply line would be below the evaluated flood height in Room 81. To address the identified issues the licensee implemented Engineering Change 62391, "FW-10 Steam Supply Line A and B Flood Barriers," Revision 0, in order to protect the AE-31 and AE-32 guard pipe vent holes and steam supply lines from flood water.

The team determined that the licensee had failed to fully evaluate all impacts of adding vent holes in the guard pipes when developing the modification.

Analysis. The failure to ensure that design requirements were correctly translated into installed plant equipment 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 affected the associated objective to ensure availability, reliability, and capability of systems that responds to initiating events to prevent undesirable consequences. Specifically, the licensee's failure to translate the design requirements into installed plant equipment resulted in a condition where the steam driven auxiliary feedwater pump may not have been able to perform its specified safety function. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because the turbine driven auxiliary feedwater pump was inoperable for longer than the technical specification allowed outage time. A regional senior reactor analyst performed a detailed risk evaluation and determined this finding to be of very low safety significance (Green) because the bounding change to the core damage frequency was approximately 1.2E-9/year. The dominant core damage sequences included feedwater and main steam line breaks with the consequential failure of the turbine driven auxiliary feedwater pump combined with other random failures of Train A and B equipment trains. Equipment that helped mitigate the risk included the diesel driven and motor-driven auxiliary feedwater pumps, which would remain functional for the vast majority of sequences. This finding has a cross-cutting aspect in the area of human performance associated with the decision-making component because the licensee failed to use conservative assumptions in decision-making and adopt a requirement to demonstrate that the proposed action is safe in order to proceed rather than a requirement to demonstrate it is unsafe in order to disapprove the action [H.1(b)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that, "measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions." Contrary to the above, measures established by the licensee did not assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from initial construction through September 26, 2013, the licensee failed to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as Condition Reports CR 2013-18308 and CR 2013-18605. (NCV 05000285/2013018-06, "Failure to Recognize Adverse Design Changes")

7. Failure to Maintain Design Control of the Auxiliary Feedwater System

Introduction. The team identified a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," associated with the licensee's failure to maintain design control of the auxiliary feedwater system.

Description. While reviewing Engineering Change 53202, "Modify Piping and Supports for FW-10 MS Supply for HELB Concerns," Revision 0, the inspectors identified that the AE-31 and AE-32 guard pipe vent holes were located below the evaluated flood height in Room 81 (05000285/2013018-06).

In order to protect the steam supply lines from flood waters resulting from a high energy line break the licensee prepared Engineering Change 62391, "FW-10 Steam Supply Line A and B Flood Barriers," Revision 0. This modification involved the installation of flood barriers, rectangular boxes without lids, surrounding the guard pipes and portions of the FW-10 steam supply lines that are below the evaluated flood height in Room 81.

The team reviewed Engineering Change 62391 and determined that the licensee had not evaluated the effects of water spraying into the flood barriers from a crack or break in any of the high energy systems in Room 81, which is the same source of water in the flood analysis. Major high energy systems in Room 81 include main steam and main feedwater systems. Water spraying into the flood barrier from a high energy line break in Room 81 could have the same effect as with the flood barrier not in place.

The team informed the licensee of their concerns, and the licensee initiated Condition Report CR 2013-22770 to capture this issue in the station's corrective action program. To address the identified issues the licensee issued a Field Design Change Request to Engineering Change 62965 to add a cover to the flood barriers.

Analysis. The failure to maintain design control of the auxiliary feedwater system 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 affected the associated objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the flood barrier installed only protected the FW-10 steam supply from flood waters rising from the floor; however, this water is postulated from a high energy line break, which would both spill onto the floor and spray into Room 81 without regard for direction. This resulted in a condition where the steam driven auxiliary feedwater pump may not have been able to perform its specified safety function. The team evaluated the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, "The Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, and determined that this finding required a detailed risk evaluation because the turbine driven auxiliary feedwater pump was inoperable for longer than the technical specification allowed outage time. A regional senior reactor analyst performed a detailed risk evaluation and determined that the finding was of very low safety significance (Green) because the bounding change to the core damage frequency was approximately 1.2E-9/year. The dominant core damage sequences included feedwater and main steam line breaks with the consequential failure of the turbine driven auxiliary feedwater pump combined with other random failures of Train A and B equipment trains. Equipment that helped mitigate the risk included the diesel driven and motor-driven auxiliary feedwater pumps, which should remain functional for the vast majority of sequences. The finding was determined to have a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action component because the licensee did not take appropriate corrective actions to address safety issues, in that, an additional modification was required to protect the FW-10 steam supply from the effects of a high energy line crack or break [P.1(d)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” states, in part, that, “measures shall be established to assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, are correctly translated into specifications, drawings, procedures, and instructions.” Contrary to the above, measures established by the licensee did not assure that applicable regulatory requirements and the design bases, as defined in 10 CFR 50.2 and as specified in the license application, for those components to which this appendix applies, were correctly translated into specifications, drawings, procedures, and instructions. Specifically, from November 24, 2013, until December 15, 2013, the licensee failed to fully incorporate applicable design requirements for components needed to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition following a high energy line break. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee’s corrective action program as Condition Reports CR 2013-18308 and CR 2013-18605. (NCV 05000285/2013018-07, “Failure to Maintain Design Control of the Auxiliary Feedwater System”)

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

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R. Haug, Senior Consultant
K. Ihnen, Manager, Site Nuclear Oversight
R. Hugenroth, Supervisor, Nuclear Assessments
E. Matzke, Senior Licensing Engineer
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M. Prospero, Division Manager, Plant Operations
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R. Short, Manager, Recovery
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K. Wells, Nuclear Design Engineer Design Electrical/I&C
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G. Wilhelmsen, Exelon Nuclear Partners
J. Zagata, Reliability Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000285/2013018-01	VIO	Failure to Correctly Translate Design Requirements into Installed Plant Configuration (Section 4OA4)
05000285/2013018-02	NCV	Use of Non-conservative Values in Design Analyses (Section 4OA4)
05000285/2013018-03	NCV	Failure to Furnish Evidence of Activities Affecting Quality (Section 4OA4)
05000285/2013018-04	NCV	Failure to Promptly Identify and Correct Inadequate Internal Flooding Analysis (Section 4OA4)
05000285/2013018-05	NCV	Use of Non-Conservative Inputs in Thermal Lag Analyses (Section 4OA4)
05000285/2013018-06	NCV	Failure to Recognize Adverse Design Changes (Section 4OA4)
05000285/2013018-07	NCV	Failure to Maintain Design Control of the Auxiliary Feedwater System (Section 4OA4)

Closed

05000285/2012-017-2	LER	Containment Valve Actuators Design Temperature Ratings Below those Required for Design Basis Accidents (Section 4OA4)
05000285/2013-011-0	LER	Inadequate Design for High Energy Line Break in Rooms 13 and 19 of the Auxiliary Building (Section 4OA4)
05000285/2013-015-1	LER	Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82 (Section 4OA4)
05000285/2013-016-0	LER	Reporting of Additional High Energy Line Break Concerns (Section 4OA4)

CONDITION REPORTS

NUMBER			
2013-12245	2013-02857	2013-12249	2013-05570
2013-11502	2013-11532	2013-08675	2012-07724
2013-05206	2013-22784	2013-15555	199600523
2011-3198	200500704	200501568	200002402
200700120	200601796	200601606	200601755
200502333	200501568	200500704	200402691
200402145	200304519	200002147	2013-21877
2013-21820	2013-20453	2013-18633	2013-18162
2013-18343	2013-18158	2013-16341	2013-14793
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2007-2692	199801227	2013-01796	920184
200700702	920468	2013-21285	2013-18639
2013-18390	2013-18253	2013-18252	2013-18086
2013-14706	2013-14703	2013-14637	2013-11287
2013-09422	2013-07551	2013-06943	2012-05244
2012-05202	2012-04847	2011-4979	200101822
199802045	2008-5517	2010-5603	2013-15223
2013-04590	2013-14637	199500039	199500437
199600082	199600137	199600331	199600340
199600353	199600400	199600639	199600786
199600791	199600858	199601225	199601226
199601321	199601368	199601403	199601405
199601491	199601624	199700008	199700177
199700198	199700205	199700422	199700426
199700472	199700475	199700473	199700495
199700782	199701020	199701073	199701160
199701261	199701532	199701566	199701623
199701679	199701710	199800072	199800376
199800828	199800855	199800888	199800889
199800915	199800918	199800938	199801153

199801225	199801227	199801822	199801826
199801877	198802168	199900484	199901002
199901103	199901198	199901492	199901677
199901953	199902001	199902028	199902047
199902321	199902307	200000377	200000699
200002018	200002147	200100051	200100391
200100690	200101212	200101367	200001921
200002145	200002525	200100374	200100606
200101093	200101352	199902276	200000133
200001844	200002079	200002402	200100372
200100577	200100959	201101332	200101300
200100909	200100536	200100368	200002401
200002079	200001511	199902515	199902183
199902129	199902485	200001495	200002065
200002345	200100317	200100507	200100894
200101288	199902123	199902417	200001078
20002050	200002252	200100290	200100476
200100827	200101255	200101382	200101581
200101597	200101873	200102142	200102204
200102283	200102386	200102440	200102482
200102491	200102306	200120470	200102598
200102654	200102873	200102985	200103118
200103278	200103285	200103316	200103369
200103499	200103499	200103565	200103573
200103831	200200898	200200906	200201000
200200720	200200970	200200973	200201112
200201144	200201140	200201368	200201564
200201851	200201563	200201557	200201319
200202320	200201237	200201840	200201705
200201619	200301841	200201612	200201593
200203684	200201924	200201860	200203079
200201950	200201923	200302036	200301129
200300403	200204171	200202827	200301044
200300772	200301590	200303065	200303438

200300251	200301628	200303165	200302959
200501758	200501809	200502284	200502286
200502281	200502242	2010-2250	2012-08621
2013-02857	2011-7463	2012-15687	2013-10907
2013-05217	2013-04395	2012-07901	2012-19124
2012-10165	2012-18937	2013-14168	2013-14477
2008-1176	2011-7462	2011-7496	2011-7494
2012-01655	200302881	200302324	200303503
200303510	200303549	200303555	200303662
200303665	200304010	200303990	2007-2452
200304189	2007-0591	2007-1969	2007-3312
2007-00613	2007-00662	2007-3435	2007-0494
2007-4815	2007-4772	2007-0354	2007-2596
2007-4787	2008-0811	2007-2540	2008-2481
2008-0990	2008-1628	2007-4352	2008-2495
2008-1630	2008-1716	2008-0195	2008-2567
2008-2253	2008-2484	2008-1602	2008-2609
2008-2491	2007-2692	2008-1707	2008-2660
2008-2489	2007-4758	2008-2482	2008-2900
2008-1813	2008-0649	2007-4007	2008-3002
2008-1629	2008-1605	2007-4967	2008-3092
2008-0930	2008-1715	2008-1569	2008-3905
2007-2925	2008-2483	2008-1706	2008-4172
2011-05242	2011-05243	2013-22770	2013-22556
2013-04544	2013-02711	2007-02715	2013-20253
2011-07496	2012-08520	2012-02498	2013-13217
2012-02115	2013-02857	2013-13217	2013-19500

PROCEDURES

NUMBER	TITLE	REVISION
PED-QP-15	Electrical Equipment Qualification Program	13
SO-G-56	Qualified Life Program	26
PED-GEI-5	Electrical Equipment Qualification Evaluation	12
EEQ	Electrical Equipment Qualification Manual –Enclosure 1	

PROCEDURES

NUMBER	TITLE	REVISION
PED-QP-2	Configuration Change Control	61
PED-GEI-60	Preparation Substitute Replacement Items	48

CALCULATIONS

FC08060	FC07885	FC08027	FC07234
FC08145	FC08025	FC06421	FC07283
EA-FC-12-205	FC04276	FC06740	FC07096
EA11-023	FC08255	FC08303	FC08302
FC08304	EA90-031	EA-FC-93-003	FC 08124
FC 05361	FC 07890	FC 08038	EA-FC-02-004

ENGINEERING CHANGES

53202	54173	54335	54246
62391	57139		

DRAWINGS

NUMBER	TITLE	REVISION
C-4113	Subsystem #MS-4099A Aux. Feedwater Pump FW-10 Pipe Routing From MS-383A Penetrations & Restraint Details	A
C-4114	Subsystem #MS-4099A Aux. Feedwater Pump FW-10 Pipe Routing from MS-381A, Penetrations, & Restraints Details	0
D-4318	CQE Piping Isometrics – Seismic Sub. System - # MS-4099A	5

MISCELLANOUS

NUMBER	TITLE	REVISION/ DATE
Technical Report 13-0376-TR-001	Metallurgical Evaluation of Small Bore Socket Welds	Rev. 0
LIC-88-0873	NRC Bulletin 88-08, Thermal Stresses in Piping Connected to Reactor Coolant Systems	
AREVA Doc No 32-9146950-000	Exemption from Fatigue for RCS attached Class 1 piping for Fort Calhoun Station	
AREVA Doc No 51-9148493-000	Fort Calhoun Code Reconciliation for Class 1 Attached Piping Reanalysis	
LIC-13-0187	Fort Calhoun Station (FCS) License Amendment	December 13,

MISCELLANOUS

NUMBER	TITLE	REVISION/ DATE
	Commitment - Piping Code Discrepancies	2013
EEQ-H-01	ASCO Solenoid NP Series Valves	21
EEQ-H-02	Namco Limit switches	23
EEQ-H-05	Conax Electrical Penetrations	9
EEQ-H-21	Rockbestos Pyrotrol Cables	9
EEQ-H-24	Victoreen Radiation Monitor	8
LER 2012-015	Electrical Equipment Impacted by HELB outside Containment	0
EEQ-H-31	Graboot Connectors	8
EEQ-H-03	ITT Conoflow	11
NED-11-0098 DEN	SMART Assignment Approval for EC 53202, “Modifying Piping and Supports for FW-10 MS Supply for HELB Concerns”	August 15, 2011

WORK ORDERS

00492949-01	00199528-01	411399-01	395469-03
54232	54039	54110	57732
62965	00455673	00455680	00455678

ACTION REQUEST

00060099	00060100

(1) The Model Revision and Other Probabilistic Risk Assessment Tools Used

The analyst utilized the Standardized Plant Analysis Risk Model for Fort Calhoun Station, Versions 8.20 and 8.21, and hand calculation methods to quantify the risk of the subject performance deficiency.

(2) Assumptions

1. The risk impact of the subject performance deficiency was limited to high-energy line breaks in the rooms or areas of concern.

2. The subject performance deficiency impacted plant risk from initial reactor startup through October 2013. Therefore, in accordance with the Risk Assessment of Operational Events Handbook, Volume 1, "Internal Events," Revision 2, Section 2.6, "Exposure Time Greater than 1 Year," the maximum exposure time was set to the 1 year assessment period.

3. The best available model for quantifying the risk for high-energy line breaks is the Standardized Plant Analysis Risk (SPAR) model for Fort Calhoun Station, Unit 1, Versions 8.20 and 8.21.

4. The analyst noted that neither version of the SPAR model provided for evaluation of conditions affecting a reactor coolant pump seal cooler loss of coolant accident. Therefore, the best available evaluation method was to create a model specifically designed for this initiator, using the SPAR Version 8.20.

5. The best available source of information related to pipe failure rates for Fort Calhoun Site is the EPRI Technical Report 3002000079.

6. The best available source of information related to failures of auxiliary steam system and their potential impacts for the Fort Calhoun Station is Combustion Engineering Nuclear Power LLC Report ST-2000-0627.

7. The failure of the diaphragms in HCV-438A and HCV-438C would be unlikely to very unlikely upon successful cooldown by operators following a reactor coolant pump seal cooler failure as described in the licensee's white paper entitled, "Overview of RCP Seal Cooler Containment Isolation Valve Elastomer Significance."

8. The change in core damage probability for all air-operated valves that fail upon loss of air to their risk-significant position would be negligible given inadequate elastomers.

9. The ΔCDF for inadequate elastomers would be negligible for all valves that fail in the direction that supports system function for the high-energy line break that causes the failure.

10. The failure of hot leg injection at the Fort Calhoun Station would only impact the plant response to a large-break loss of coolant accident.

11. The inability of operators to sample the containment environment following an accident would not significantly impact the core damage frequency.

12. Components that exceeded their harsh environment qualification limits during a postulated event would fail.

13. Upon failure of the elastomers in an air-operated valve, the valve would move to the position it was designed for upon loss of instrument air.

14. Overfilling of the steam generators results in failure of Pump FW-10, Turbine-Driven Auxiliary Feedwater Pump, via flooding of the steam supply line.

15. A break in the auxiliary steam system piping in either diesel generator room would not result in a direct transient.

16. Following a postulated break in the auxiliary steam system piping in either diesel generator room, the associated diesel generator would be restored to operable status within the Technical Specification allowed outage time or the plant would be shut down and cooled down.

17. A failure frequency of 1 x 10^{-3}/year provides a clear upper bound for the frequency of an auxiliary steam system pipe break in any room in the plant.

18. Upon a postulated auxiliary steam line break on the Intake Structure operating deck the rotating screens would fail causing a loss of raw water.

19. The change in failure frequency of socket welded pipe caused by the lack of ability to perform nondestructive examination can be bounded by increasing the failure frequency by a factor of approximately 100.

20. Given the as-found condition of the turbine-driven auxiliary feedwater pump steam supply piping guard pipe, a postulated failure of the supply piping would supply steam to Room 56E in sufficient quantities to fail the 1A3 side electrical busses in the room.

21. The licensee's initiating event frequencies for main-steam line break and main feedwater line break outside containment include a wide range of pipe break sizes.

22. Given Assumption 21, the use of the licensee's initiating event frequencies for an evaluation of post-break flooding in Room 81 provides an upper bound.

(3) Calculation discussion

The licensee failed to correctly translate the design requirements associated with high-energy line breaks into structures, systems, and components necessary to bring the reactor to safe shutdown. The analyst determined that this performance deficiency affected plant risk in three ways. Specifically:

(1) Fifty-eight air-operated valves had diaphragms and/or other elastomers that were not qualified for the harsh environment they would be subjected to following a postulated accident and/or high-energy line break. The characterization of each of these valves is documented in Table 1.

(2) Nineteen areas in the plant contained auxiliary steam system piping. The licensee had not evaluated these areas for breaks in the auxiliary steam system piping, resulting in some components not being capable of withstanding such an environment. The plant areas and the functional groups identified for these areas are documented in Table 4.

(3) Five areas in the plant contained high-energy piping that had not been evaluated for breaks. As a result, multiple risk-significant components were not properly protected or qualified for the resulting harsh environment. The characterization of these areas is documented in Table 5.

<u>Evaluation 1: Air-Operated Valves with Inappropriate Elastomers</u>

The licensee identified 58 air-operated valves had diaphragms and/or other elastomers that were not qualified for the harsh environment they would be subjected to following a postulated accident and/or high-energy line break. The analyst identified similarities among various valves and grouped them into nine functional groups to simplify the analysis. The functional groups and characterization of these valves are documented in Table 1.

Table 1 Air-Operated Valves Containing Inappropriate Elastomers						
Valve	Description	Location	Group	Frequency (per year)	Bounding CCDF	ΔCDF
HCV-1107A	STEAM GENERATOR RC-2A ; AUXILIARY FEEDWATER INLET VALVE	Containment	3	8.46×10^{-4}	2.75×10^{-3}	7.19×10^{-9}
HCV-1108A	STEAM GENERATOR RC-2B ; AUXILIARY FEEDWATER INLET VALVE	Containment	3	8.46×10^{-4}	2.75×10^{-3}	7.19×10^{-9}
IA-HCV-1107A-FR	HCV-1107A INSTRUMENT AIR SUPPLY FILTER/REGULATOR	Containment	3	8.46×10^{-4}	2.75×10^{-3}	7.19×10^{-9}
IA-HCV-1108A-FR	HCV-1108A INSTRUMENT AIR SUPPLY FILTER/REGULATOR	Containment	3	8.46×10^{-4}	2.75×10^{-3}	7.19×10^{-9}
HCV-238	REACTOR COOLANT SYSTEM LOOP 1A CHARGING LINE STOP VALVE	Containment	4	8.46×10^{-4}	4.92×10^{-3}	7.55×10^{-9}
HCV-239	REACTOR COOLANT SYSTEM LOOP 2A CHARGING LINE STOP VALVE	Containment	4	8.46×10^{-4}		Note 1
HCV-240	PRESSURIZER RC-4 ; AUXILIARY SPRAY INLET VALVE	Containment	4	8.46×10^{-4}		Note 1
IA-HCV-238-FR	HCV-238 INSTRUMENT AIR SUPPLY FILTER/REGULATOR	Containment	4	8.46×10^{-4}		Note 1
IA-HCV-239-FR	HCV-239 INSTRUMENT AIR SUPPLY FILTER/REGULATOR	Containment	4	8.46×10^{-4}		Note 1
IA-HCV-240-FR	HCV-240 INSTRUMENT AIR SUPPLY FILTER/REGULATOR	Containment	4	8.46×10^{-4}		Note 1
PCV-742G	RADIATION MONITORING CABINET ; INLET INBOARD ISOLATION VALVE	Containment	8	8.46×10^{-4}	0.0	0.0
HCV-1107B	STEAM GENERATOR RC-2A AUXILIARY FEEDWATER INLET VALVE	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}
HCV-1108B	STEAM GENERATOR RC-2B AUXILIARY FEEDWATER INLET VALVE	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}
IA-HCV-1107B-FR1	AUX FEED INLET VALVE HCV-1107B NORMAL AIR SUPPLY FILTER REGULATOR	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}
IA-HCV-1107B-FR2	AUX FEED INLET VALVE HCV-1107B BACKUP AIR SUPPLY FILTER	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}

Table 1 Air-Operated Valves Containing Inappropriate Elastomers						
Valve	Description	Location	Group	Frequency (per year)	Bounding CCDF	ΔCDF
	REGULATOR					
IA-HCV-1108B-FR1	AUX FEED INLET VALVE HCV-1108B NORMAL AIR SUPPLY FILTER REGULATOR	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}
IA-HCV-1108B-FR2	AUX FEED INLET VALVE HCV-1108B BACKUP AIR SUPPLY FILTER REGULATOR	AB081	3	4.80×10^{-4}	2.96×10^{-4}	1.19×10^{-10}
YCV-1045A-O	MAIN STEAM LINE "A" TO ; AUX FEEDWATER PUMP FW-10 ; SUPPLY VALVE	AB081	5	4.80×10^{-4}	0.0	0.0
YCV-1045B-O	MAIN STEAM LOOP "B" ; AUX FEEDWATER PUMP FW-10 ; SUPPLY VALVE	AB081	5	4.80×10^{-4}	0.0	0.0
HCV-2898A	CONTROL ROOM VA UNIT VA-46A CCW INLET VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
HCV-2898B	CONTROL ROOM VA UNIT VA-46A CCW OUTLET VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
HCV-2899A	CONTROL ROOM VA UNIT VA-46B CCW INLET VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
HCV-2899B	CONTROL ROOM VA UNIT VA-46B CCW OUTLET VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
PCV-6680A-1	CONTROL ROOM FAN VA-63A SUCTION PRESS CONTROL VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
PCV-6680A-2	CONTROL ROOM FILTER VA-64A DISCHARGE PRESSURE CONTROL VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
PCV-6680B-1	CONTROL ROOM FAN VA-63B SUCTION PRESS CONTROL VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
PCV-6680B-2	CONTROL ROOM FILTER VA-64B DISCHARGE PRESS CONTROL VALVE	AB081	6	4.80×10^{-4}	0.0	0.0
HCV-400B	CNTMT VA-1A COOLING COIL ; CCW	AB069	2	9.6×10^{-5}	0.0	0.0

Table 1 Air-Operated Valves Containing Inappropriate Elastomers						
Valve	Description	Location	Group	Frequency (per year)	Bounding CCDF	ΔCDF
	INLET VALVE					
HCV-400D	CONTAINMENT COOLING COIL VA-1A; CCW RETURN ISOLATION VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-401B	CONTAINMENT COOLING COIL VA-1B; CCW INLET ISOLATION VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-401D	CONTAINMENT COOLING COIL VA-1B; CCW RETURN ISOLATION VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-402B	CNTMT VA-8A COOLING COIL ; CCW INLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-402D	CNTMT VA-8A COOLING COIL ; CCW OUTLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-403B	CNTMT VA-8B COOLING COIL ; CCW INLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-403D	CNTMT VA-8B COOLING COIL ; CCW OUTLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-400A	CNTMT VA-1A COOLING COIL ; CCW INLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-400C	CNTMT VA-1A COOLING COIL ; CCW OUTLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-401A	CONTAINMENT COOLING COIL VA-1B; CCW SUPPLY ISOLATION VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-401C	CNTMT VA-1B COOLING COIL ; CCW OUTLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-402A	CNTMT VA-8A COOLING COIL ; CCW INLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-403A	CNTMT VA-8B COOLING COIL ; CCW INLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-403C	CNTMT VA-8B COOLING COIL ; CCW OUTLET VALVE	AB069	2	9.6×10^{-5}	0.0	0.0
HCV-1559B	DEMIN WATER SUPPLY CONTAINMENT	AB069	1	9.6×10^{-5}	0.0	0.0

Table 1 Air-Operated Valves Containing Inappropriate Elastomers						
Valve	Description	Location	Group	Frequency (per year)	Bounding CCDF	ΔCDF
	ISOLATION VALVE					
IA-HCV-401A-R	CCW INLET VALVE HCV-401A INSTRUMENT AIR PRESSURE REGULATOR	AB069	1	9.6×10^{-5}	0.0	0.0
HCV-344-P	CONTAINMENT SPRAY HEADER ISOLATION VALVE	AB059	1	5.0×10^{-4}	0.0	0.0
HCV-345-P	CONTAINMENT SPRAY HEADER ISOLATION VALVE	AB059	1	5.0×10^{-4}	0.0	0.0
FCV-1368	AUX FEEDPUMP FW-6 RECIRC CONTROL VALVE	AB019	1	8.4×10^{-5}	0.0	0.0
FCV-1369	TURBINE-DRIVEN AUX FEED PUMP FW-10 RECIRCULATION VALVE	AB019	1	8.4×10^{-5}	0.0	0.0
YCV-1045-O	AUX FEEDWATER PUMP FW-10 ; INLET VALVE	AB019	1	8.4×10^{-5}	0.0	0.0
HCV-2987	HPSI ALTERNATE HEADER ISOLATION VALVE	AB013	7	2.5×10^{-6}	0.1	2.50×10^{-7}
HCV-438B	RCP RC-3A-D LUBE OIL & SEAL CLRS; CCW INLET OUTBOARD ISO VALVE	AB013	9	5.0×10^{-4}	7.62×10^{-3}	3.81×10^{-6}
HCV-438D	RCP RC-3A-D LUBE OIL & SEAL CLRS; CCW OUTLET OUTBOARD ISOL VLV	AB013	9	5.0×10^{-4}		NOTE 2
HCV-480	SHUTDOWN COOLING HT EXCH AC-4A ; CCW INLET VALVE	AB004	1	5.0×10^{-4}	0.0	0.0
HCV-481	SHUTDOWN COOLING HT EXCH AC-4B ; CCW INLET VALVE	AB004	1	5.0×10^{-4}	0.0	0.0
HCV-484	SHUTDOWN COOLING HT EXCH AC-4A ; CCW OUTLET VALVE	AB004	1	5.0×10^{-4}	0.0	0.0
HCV-485	SHUTDOWN COOLING HT EXCH AC-4B ; CCW OUTLET VALVE	AB004	1	5.0×10^{-4}	0.0	0.0
HCV-438A	RCP RC-3A-D LUBE OIL & SEAL CLRS; CCW INLET INBOARD ISO VALVE	Containment	9	5.0×10^{-4}		NOTE 2
HCV-438C	RCP RC-3A-D LUBE OIL & SEAL CLRS;	Containment	9	5.0×10^{-4}		NOTE 2

Table 1 Air-Operated Valves Containing Inappropriate Elastomers						
Valve	Description	Location	Group	Frequency (per year)	Bounding CCDF	ΔCDF
	CCW INLET INBOARD ISO VALVE					
Total Change in Core Damage Frequency for Inappropriate Elastomers:						4.10×10^{-6}

NOTES:

NOTE 1: All Group 4 valves were analyzed together. The total risk is documented as the risk for Valve HCV-238 in Table 1.
NOTE 2: The various failure modes and combinations for the valves in Group 9 were analyzed in a single model. The total risk evaluated for all four valves is documented as the risk for Valve HCV-438B in Table 1.

Group 1: Valves fail in the safety/risk-significant direction.
Group 2: For the harsh environment of concern, the valves would fail in the risk-significant direction.
Group 3: Valves would fail open and increase the likelihood of over filling the steam generators.
Group 4: Valve failures affect hot leg injection and are only of concern during large-break loss of coolant accidents.
Group 5: These valves fail in the risk-significant direction (open), but are required to isolate a failure of line.
Group 6: These valves do not have a risk-significant function for high-energy line break.
Group 7: Valve is normally open and fails as is. Open is dominant risk function. Valve must close for hot leg injection.
Group 8: Valve fails closed effecting containment isolation, but sampling function is lost.
Group 9: Component cooling water isolation valves affect plant response to reactor coolant pump heat exchanger intersystem loss of coolant accident.

For the 58 valves in Table 1, the licensee had determined that each of these valves contained the elastomer Nitrile which would be exposed to elevated temperatures beyond its nominal design range following postulated high-energy line break scenarios. While the Nitrile elastomers are not rated for operation in harsh environments, the licensee noted that manufacturers' literature indicates that operation of elastomers for restricted time periods in these environments may be acceptable. The analyst evaluated each of the valve groups from Table 1 as follows:

Group 1: All Group 1 valves were determined to fail in the risk-significant direction. Should the elastomers in any of these valve actuators fail, springs would drive the valve in the appropriate direction. Therefore, the change in risk, given the performance deficiency was negligible for these valves.

Group 2: The analyst noted that Group 2 valves had risk-significant functions that required the valve to open or close depending on the system function demanded. The analyst reviewed the initiating events that would result in a harsh environment surrounding each valve. In each case, the risk-significant function of the valve following the initiator causing the harsh environment was to go to the failed position. Should the elastomers in the valve actuator fail, springs would drive the valve in the appropriate direction. Therefore, the change in risk, given the performance deficiency was negligible for these valves.

Group 3: The analyst determined that all Group 3 valves would fail open and increase the likelihood of over filling the steam generators. Over filling the steam generators, while providing additional short-term cooling, results in the failure of the turbine-driven auxiliary feedwater pump by flooding the steam supply line. The analyst used the Standardized Plant Analysis Risk (SPAR) Model for Fort Calhoun Station, Version 8.20 to quantify a bounding conditional core damage probability ($CCDP_{FW-10}$) for the loss of Feedwater Pump FW-10 following a high-energy line break. The baseline ($CCDP_{Base}$) for each scenario was also quantified. In accordance with Assumption 2, the exposure period (EXP) used was one year. The frequency ($\lambda_{Containment}$) of a high-energy line break for containment was determined to be approximately the sum of the frequencies of the following initiators:

From plant-specific SPAR model:

- Large-break loss of coolant accident (2.50×10^{-6} /year)
- Medium-break loss of coolant accident (1.50×10^{-4} /year)
- Small-break loss of coolant accident (3.67×10^{-4} /year)
- Reactor vessel rupture (1.00×10^{-7} /year)

From licensee's probabilistic risk assessment:

- Main steam line break inside containment (2.10×10^{-4} /year)
- Main feedwater line break inside containment (7.70×10^{-5} /year)
- Main feedwater line break upstream of check valve (3.90×10^{-5} /year)

The resulting high-energy line break frequency for containment was 8.46×10^{-4} /year.

The frequency ($\lambda_{Room\ 81}$) of a high-energy line break in auxiliary building Room 81 was determined to be approximately the sum of the frequencies of the following initiators:

- Main Steam Line Break (1.80×10^{-4} /year)
- Main Feedwater Line Break (3.00×10^{-4} /year)

The resulting high-energy line break frequency for Room 81 was 4.80×10^{-4}/year.

The analyst noted that for each high-energy line break initiator; there was an alternate valve in another area that was not impacted directly by the harsh environment. Should the alternate valve close, the steam generators would not overfill. Therefore, the analyst used a single train failure rate (P_{Random}) of 1.0×10^{-2} to account for the random failure of the opposite train valve.

The analyst determined that a high-energy line break in Room 81 was best represented by a loss of main feedwater initiator in the site-specific SPAR model. The analyst quantified the conditional core damage probability for a loss of main feedwater ($CCDP_{BaseMF81}$) as the baseline for breaks in Room 81 (4.75×10^{-6}). Given the performance deficiency, over filling of steam generators is possible and would fail Pump FW-10. The analyst quantified the conditional core damage probability for this scenario ($CCDP_{MF\text{-}FW\text{-}10}$) providing a probability of 2.96×10^{-5}. For each of the six valves in Room 81, the analyst hand calculated the ΔCDF as follows:

$$\begin{aligned}\Delta CDF &= \lambda_{Room\ 81} * EXP * (CCDP_{MF\text{-}FW\text{-}10} - CCDP_{BaseMF81}) * P_{Random}\\ &= 4.80 \times 10^{-4}\ /year * 1\ year * (2.96 \times 10^{-5} - 4.75 \times 10^{-6}) * 1.0 \times 10^{-2}\\ &= 1.19 \times 10^{-10}\end{aligned}$$

The analyst determined that a high-energy line break in Containment was best represented by a large-break loss of coolant accident in the site-specific SPAR model. The analyst quantified the conditional core damage probability for this initiator ($CCDP_{BaseLL}$) as the baseline for breaks in Containment (1.90×10^{-3}). Given the performance deficiency, over filling of steam generators is possible and would fail Pump FW-10. The analyst quantified the conditional core damage probability for this scenario ($CCDP_{LL\text{-}FW\text{-}10}$) providing a probability of 2.75×10^{-3}. For each of the four valves in Containment, the analyst hand calculated the ΔCDF as follows:

$$\begin{aligned}\Delta CDF &= \lambda_{Containment} * EXP * (CCDP_{LL\text{-}FW\text{-}10} - CCDP_{BaseLL}) * P_{Random}\\ &= 8.46 \times 10^{-4}\ /year * 1\ year * (2.75 \times 10^{-3} - 1.90 \times 10^{-3}) * 1.0 \times 10^{-2}\\ &= 7.19 \times 10^{-9}\end{aligned}$$

The analyst noted that the total ΔCDF for Group 3 valves was the sum of the change for each individual valve: 3.70×10^{-8}.

<u>Group 4</u>: The analyst noted that all Group 4 valves would affect the reliability of hot leg injection upon failure. Hot leg injection is a necessary function to ensure that there will not be unacceptably high concentrations of boric acid in the core region (resulting in precipitation of a solid phase) during the long-term cooling phase following a postulated large-break loss of coolant accident. The analyst noted that failure of the Group 4 valves would not cause a complete loss of hot-leg injection capability.

Alternate hot-leg injection would be available through motor-operated valves, and solenoid-operated valves, in series provided redundancy to isolate the lines affected.

Using the SPAR model, the analyst noted that the frequency of a large-break loss of coolant accident (λ_{LLOCA}) was 2.5×10^{-6} /year. The analyst quantified the model to determine the conditional core damage probability for a large-break loss of coolant accident and failure of all Group 4 valves. The analyst used Basic Event LPI-XHE-XM-HTLEG, "Operator Fails to Initiate LPR Hot Leg Recirculation," as a surrogate for the failure of the valves. Substituting the baseline failure of this basic event for an estimated 4.0×10^{-3} probability that alternate methods of hot leg injection would fail resulted in a conditional core damage probability ($CCDP_{Group4}$) of 4.92×10^{-3}. The baseline conditional core damage probability ($CCDP_{Base}$) was 1.9×10^{-3} for a large-break loss of coolant accident. The analyst hand calculated the ΔCDF as follows:

$$\begin{aligned}\Delta CDF &= \lambda_{LLOCA} \ * \ EXP \ * \ (CCDP_{Group4} - CCDP_{Base}) \\ &= 2.5 \times 10^{-6} \text{ /year} \ * \ 1 \text{ year} \ * \ (4.92 \times 10^{-3} - 1.90 \times 10^{-3}) \\ &= 7.55 \times 10^{-9}\end{aligned}$$

<u>Group 5</u>: Given a high-energy line break, valves in Group 5 would fail open. To maintain the steam supply to the turbine-driven auxiliary feedwater pump, Group 5 valves failing open supports the risk-significant function. However, these valves are also required to isolate a line break in the steam supply line. The analyst reviewed Drawing 11405-M-252, Sheet 1, "Flow Diagram Steam P & ID." The analyst did not identify any line break in Room 81 that would degrade the function of Pump FW-10 because of the failure to isolate the break. Therefore, the change in risk, given the performance deficiency was negligible for these valves.

<u>Group 6</u>: The analyst reviewed the function for each of the eight valves in Group 6. The postulated failure of these valves would only occur with a high-energy line break in auxiliary building Room 81. Given this line break, the valves in Group 6 would fail closed when the risk-significant function is open. However, the analyst determined that the risk-significant function for Group 6 valves would not be needed in response to a high-energy line break in auxiliary building Room 81. Therefore, the change in risk, given the performance deficiency was negligible for these valves.

<u>Group 7</u>: Valve HCV-2987, "HPSI Alternate Header Isolation Valve," is the only valve in Group 7. The valve is maintained open during normal plant operations and would fail 'as-is' given a high-energy line break. The analyst noted that open is the dominant risk function for this valve. However, the valve is required to close for hot leg injection. Hot leg injection is a necessary function to ensure that there will not be unacceptably high concentrations of boric acid in the core region (resulting in precipitation of a solid phase) during the long-term cooling phase following a postulated large-break loss of coolant accident. Using the SPAR model, the analyst noted that the frequency of a large-break loss of coolant accident (λ_{LLOCA}) was 2.5×10^{-6} /year. The analyst quantified the model to determine that the conditional core damage probability for a large-break loss of coolant accident and failure of all hot leg injection was 1.0 ($CCDP_{HLI}$). The analyst determined that there would be sufficient time following a large-break loss of coolant accident for operators to safely enter Room 13 and manually reposition Valve HCV-2987. Therefore, the analyst provided a screening value (P_{screen}) of 0.1 for the probability that operators failed to reposition the valve prior

to the need for hot leg injection. The baseline conditional core damage probability ($CCDP_{Base}$) was 1.9×10^{-3} for a large-break loss of coolant accident. The analyst hand calculated the ΔCDF as follows:

$$\begin{aligned} \Delta CDF &= \lambda_{LLOCA} \ * \ EXP \ * \ (CCDP_{HLI} - CCDP_{Base}) \ * \ P_{screen} \\ &= 2.5 \times 10^{-6} \text{ /year} \ * \ 1 \text{ year} \ * \ (1.0 - 1.90 \times 10^{-3}) \ * \ 1.0 \times 10^{-1} \\ &= 2.50 \times 10^{-7} \end{aligned}$$

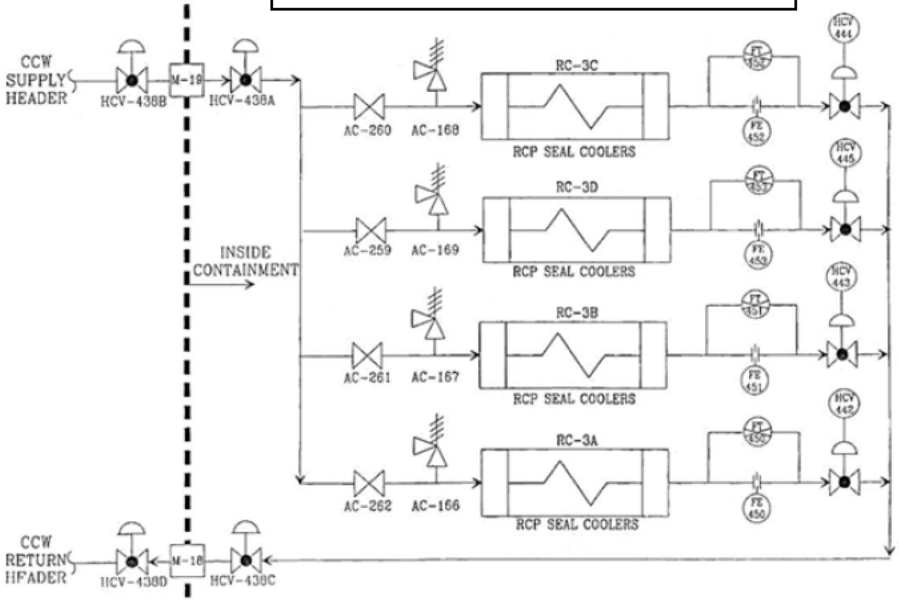
<u>Group 8</u>: Valve PCV-742G, “Radiation Monitoring Cabinet; Inlet Inboard Isolation Valve,” is the only valve in Group 8. The risk-significant function for the valve is to close, supporting containment isolation. Given a high-energy line break, Valve PCV-742G would fail closed. The primary operational function of the valve is to open following an accident to sample the containment environment. The analyst determined that, while the inability to sample would cause difficulties in understanding the condition of the containment environment, it would not have an impact on the core damage frequency. Therefore, the change in risk, given the performance deficiency was negligible for this valve.

<u>Group 9</u>: Group 9 consists of Valves HCV-428A, HCV-438B, HCV-438C, and HCV-438D. These valves are the inlet and outlet containment isolation valves for component cooling water going to the reactor coolant pump seal coolers. The valves have two primary functions:

1) To close for containment isolation, and
2) To close to isolate a postulated intersystem loss of coolant accident following a break of one of four reactor coolant pump seal cooler helix coils.

A one-line diagram of the seal coolers and the Group 9 valves is provided as Figure 1.

Figure 1
RCP Seal Coolers
One-Line Drawing



The analyst quantified the risk of the Group 9 valves as a package. The analyst noted that the SPAR model did not quantify the effects of the failure of the Group 9 valves. Therefore, the analyst developed a model using the SPAR, Version 8.20. The primary event tree for the seal cooler failure is shown in Figure 3. The initiating event frequency was taken from the licensee's probabilistic safety analysis (5.0×10^{-4}/year). The following top events were included in the tree:

1. Top Event "RPS," provided from the SPAR, models the probability that the reactor protection system fails to actuate following the initiator. Failure of the system transfers the tree to the anticipated transient without scram tree from the SPAR.

2. Figure 4 shows the top event, "Inboard-Isol." This fault tree was created by the analyst and added to the event tree to account for the potential that operators fail to isolate the intersystem loss of coolant accident following the failure of the component cooling water system surge tank. The value provided was the single failure to close probability of an air-operated valve from the SPAR model. Upon failure the model transfers to the intersystem loss of coolant accident – shutdown cooling event tree, from the SPAR, as a surrogate to the operators' ability to diagnose and recover from the event.

3. Top Event "FW," provided from the SPAR, models the likelihood that all water sources will fail to feed the steam generators including main and auxiliary feedwater.

4. Top Event "HPI," provided from the SPAR, models various failure modes of the high pressure injection system.

5. Top Event "SSC," provided from the SPAR, models various failures of the secondary plant systems that would prevent normal cool down of the plant.

6. Top Event "OTC," provided from the SPAR, models failures of the high pressure injection system and the primary power-operated relief valves, failures of which would prevent the feed and bleed function described in the emergency operating procedures.

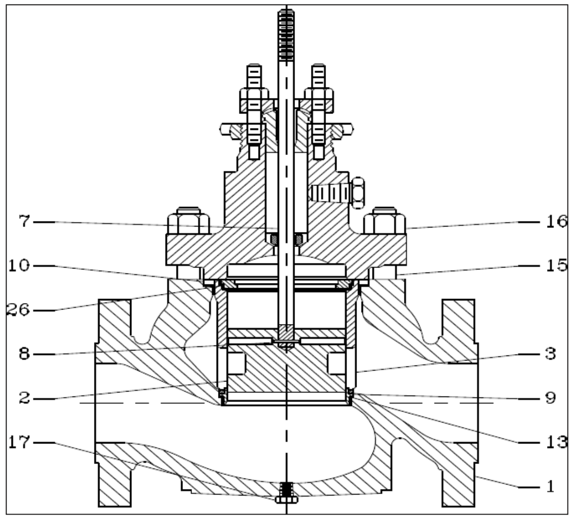
7. Top Event "CSR," provided from the SPAR, models various failure modes of the containment spray system assuming that containment coolers are unavailable because of failure of the component cooling water system.

8. Figure 5 shows the top event, "Inboard-Iso-Holds." This fault tree was created by the analyst and added to the event tree to account for the potential that Valves HCV-438A and HCV-438C operators fail to remain closed in the containment environment created by a small-break loss of coolant accident. The failure of the valves as a result of the performance deficiency were modeled differently at high reactor coolant system pressures and following a reactor depressurization directed by the emergency operating procedures. The failure probabilities used were developed by the analyst using qualitative information provided by the licensee in a white paper entitled, "Overview of RCP Seal Cooler Containment Isolation Valve Elastomer Significance." The analyst noted that these valves would remain closed with a differential pressure of approximately 300 psig based on the design of the plug (See Figure 2).

   The licensee performed an assessment to provide background information regarding the high temperature behavior of Nitrile, the substance used as the primary elastomer in the 58 subject valves. The Parker O-ring handbook (Reference 1) indicated that Nitrile materials can be used for limited periods when exposed to temperatures in the 200-300 degrees Fahrenheit range. However, that handbook does not specify a relationship between Nitrile lifetime and exposure temperature. Other references, including earlier versions of the Parker handbook have provided time/temperature relationships for various elastomers. The licensee extrapolated this information to estimate the lifetime-exposure temperature relations for Nitrile for the purposes of gaining insight with regard to risks of loss of function for selected valves with Nitrile components. Specifically, this information was used to support the licensee's judgments regarding the failure probability of Nitrile when subjected to limited duration exposures to elevated temperatures beyond their nominal design ranges.

   Valves HCV-438A, HCV-438B, HCV-438C, and HCV-438D use Nitrile based elastomers for the air filter regulator and actuator. Valves HCV-438A and HCV-438C, located in containment, perform a function in the closed position to establish containment isolation upon receipt of a Containment Isolation Actuation Signal coincident with Component Cooling Water low pressure. These valves fail open.

Figure 2
CCW Isolation Valve Design



1	Body	**10**	Spiral Wound Gasket, Shim, and Bonnet gasket
2	Plug	**13**	Seat Ring Gasket
3	Cage	**15**	Stud
7	Stem	**16**	Nut
8	Groove Pin	**17**	Body Drain
9	Seat Ring	**26**	Load Ring (8 inch only)

9. Figure 6 shows the top event, “Out-Iso-Holds.” This fault tree was created by the analyst and added to the event tree to account for the potential that Valve Operators for HCV-438B and HCV-438D fail to remain closed against the differential pressure created when Valves HCV-438A and HCV-438C fail open following a break of one of four reactor coolant pump seal cooler helix coils. The analyst noted that the valves would fail open under differential pressures near 180 psig, indicating that the valves would most likely always fail open. However, Emergency Operating Procedure EOP-20, “Functional Recovery Procedure,” Step 14.c.2 directs operators to manually close these valves with a hand jack. The analyst used a screening value of 0.1 as the human error probability for operators failing to close the outboard valves. This action requires depressurization of the reactor coolant system; an environment in Room 13 that would permit operator access; and access to necessary equipment.

10. Top Event “SDC,” provided from the SPAR, models various failures of the shutdown cooling system that would prevent placing the plant in cold shutdown.

11. Top Event “HPR,” provided from the SPAR, models various failures of the high pressure injection system and other components that would prevent establishing recirculation by successfully transferring the system suction source from the refueling water storage tank to the containment sump.

12. Top Event “LSHR,” provided from the SPAR, models the failure of operators to refill the emergency feedwater storage tank so that long-term secondary heat removal can continue if depressurization of the reactor is not successful.

The analyst quantified the event tree shown in Figure 3 using the SAPHIRE software and quantification engine with a truncation value of 1×10^{-13}. For the reader’s benefit, the approximate split fractions for each top event are provided in Table 2. The sequence results for the baseline and case evaluations are documented in Table 3. The total ΔCDF for the Group 9 valves was determined to be 3.8×10^{-6}.

Figure 3
RCP Seal Cooler LOCA
Event Tree

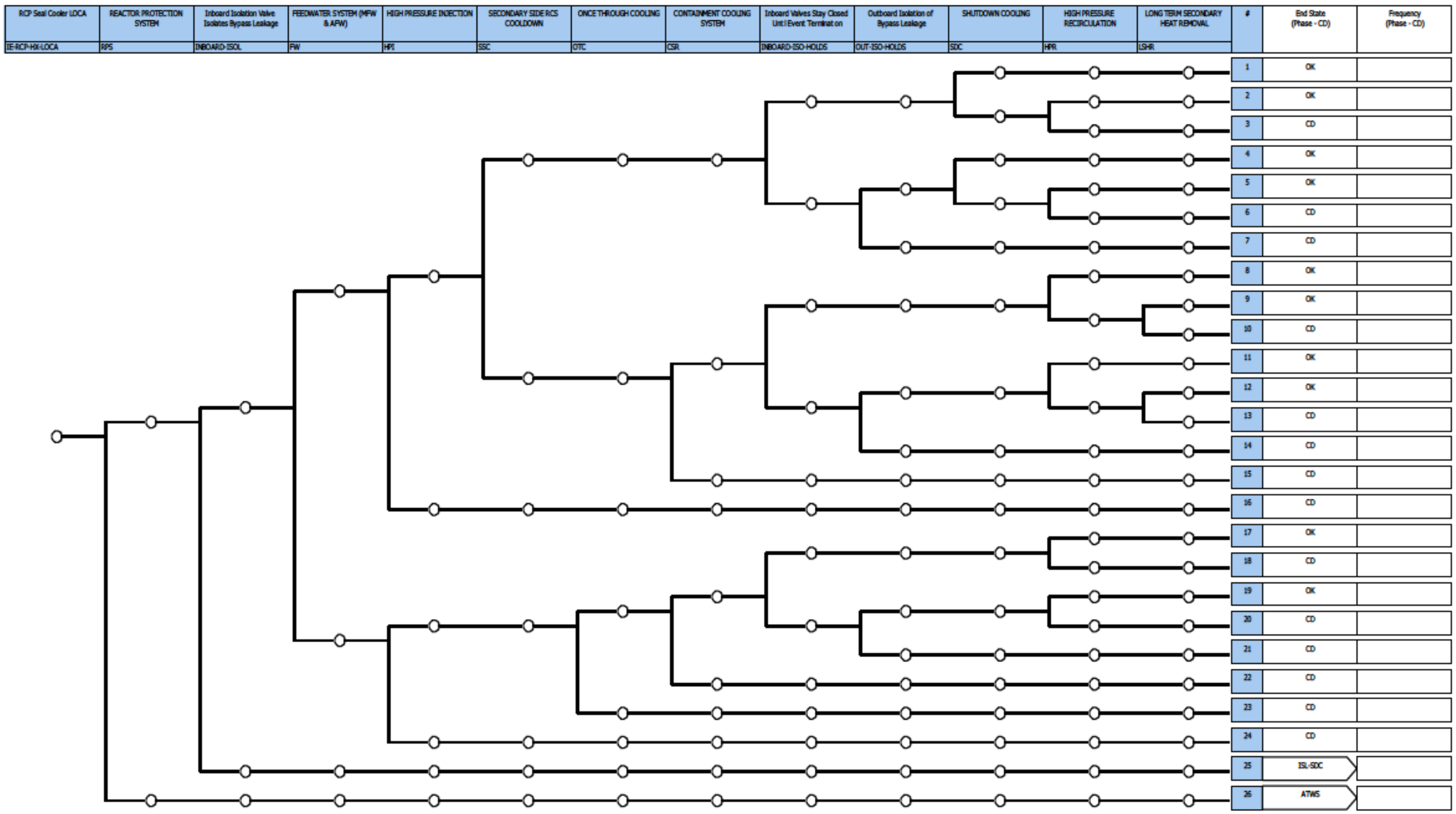


Figure 4
Failure to Isolate Group 6 Valves
Event Tree

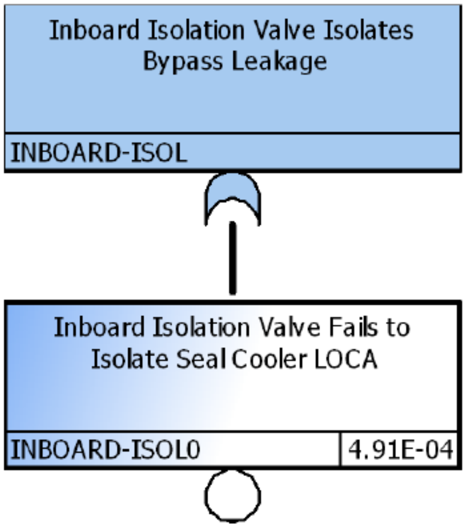


Figure 5
Failure of Outboard Group 6 Valves to Remain Closed
Event Tree

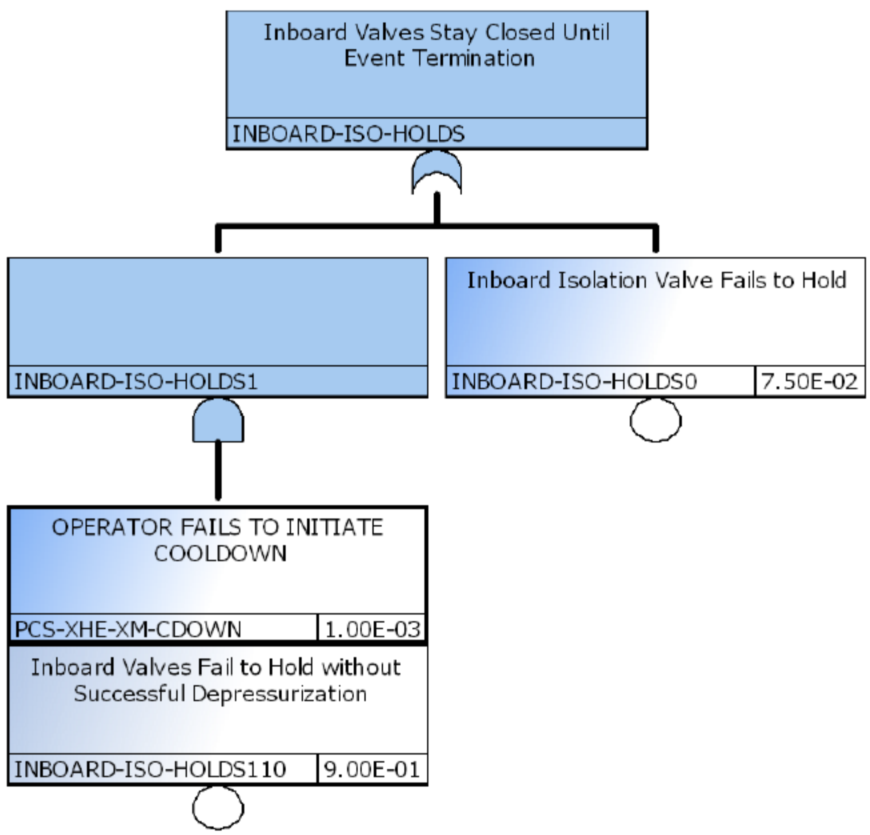


Figure 6
Failure of Inboard Group 6 Valves to Remain Closed
Event Tree

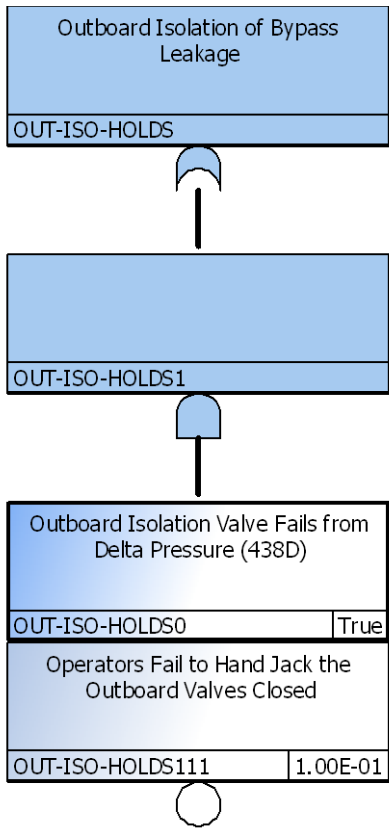


Table 2 Split Fractions for Reactor Coolant Pump Seal Cooler Loss of Coolant Accident Event Tree		
Top Event	Definition	Probability
Initiator	Reactor Coolant Pump Seal Cooler Failure (/year)	5.00E-04
RPS	Failure of the Reactor Protection System	2.04E-06
Inboard-Isol	Failure to Isolate Component Cooling Water to the Seal Cooler	4.91E-04
FW	Failure of the Main and Auxiliary Feedwater Systems	4.77E-04
HPI	Failure of High Pressure Injection	6.11E-02
SSC	Failure to Cool Down the Reactor using Secondary Systems	1.05E-03
OTC	Failure of Once Through Cooling	8.71E-02
CSR	Failure of the Containment Cooling Systems	8.37E-05
Inboard-Iso-Holds	Valves 438A and C fail from Inappropriate Elastomers	7.58E-02
Out-Iso-Holds	Valves 438B and D Reopen and Operators Fail to Manually Close	1.00E-01
SDC	Failure of Shutdown Cooling	7.42E-03
HPR	Failure of High Pressure Recirculation	6.13E-02
LSHR	Failure of Long-Term Secondary Heat Removal	1.00E-04

Table 3 Sequence Results for Seal Cooler Failure Event Tree		
Sequence:	Sequence Frequency (per year)	Baseline Frequency (per year)
3	3.22E-08	3.22E-08
6	2.20E-09	2.20E-09
7	3.79E-06	
10	3.22E-12	3.22E-12
13	2.20E-13	2.20E-13
14	3.98E-09	
15	4.39E-11	4.39E-11
16	3.06E-05	3.06E-05
18	1.46E-08	1.46E-08
20	9.97E-10	9.97E-10
21	1.81E-09	
22	2.00E-11	2.00E-11
23	2.08E-08	2.08E-08
24	1.46E-08	1.46E-08
25	2.46E-07	2.46E-07
26	1.02E-09	1.02E-09
Total	3.47E-05	3.09E-05
Total ΔCDF		3.80E-06

Results for Section 1, "Air-Operated Valve Elastomers"

The analyst determined that the total best estimate ΔCDF for all air-operated valves with inappropriate elastomers was the sum of the independent ΔCDF for each valve. Therefore, the best estimate ΔCDF for this portion of the risk related to the performance deficiency was 4.1×10^{-6} as documented in Table 1.

Evaluation 2: Auxiliary Steam System Piping Breaks

The licensee identified 19 areas in the plant that contained auxiliary steam system piping. The licensee had not evaluated these areas for breaks in the auxiliary steam system piping, resulting in some components not being capable of withstanding such an environment. The analyst identified similarities among various valves and grouped them into four functional groups to simplify the analysis. The functional groups identified, and the grouping of each of these valves, are documented in Table 4.

TABLE 4
Auxiliary Steam System Area Groups

Room	Description	Location	Group
4	Open Corridor: Contains several Motor-Control Centers that support HCV-347 and HCV-348, "Shutdown Cooling Suction Valves," and HCV-383-3 and HCV-383-4, "Sump Suction Valves"	Auxiliary Building	Not Harsh
5	Spent Fuel Pool Heat Exchanger Room	Auxiliary Building	No PRA
6	Changing Pumps Room	Auxiliary Building	Not Harsh
19	Compressor Room: Includes Steam-Driven and Motor-Driven Auxiliary Feedwater Pumps	Auxiliary Building	Not Harsh
26	Open Corridor: Boric Acid Pumps and Tanks	Auxiliary Building	Not Harsh
30	Waste Evaporator Room	Auxiliary Building	No PRA
31	Storage Room	Auxiliary Building	No PRA
56	Switchgear Room (Vital and Nonvital)	Auxiliary Building	Not Harsh
57	Electrical Penetration Area	Auxiliary Building	Not Harsh
63	Diesel Generator Room 1	Auxiliary Building	Harsh
64	Diesel Generator Room 2	Auxiliary Building	Harsh
65	Diesel Ventilation Enclosure	Auxiliary Building	Not Harsh
66	Equipment Hatch Enclosure	Auxiliary Building	Not Harsh
69	Ventilation Equipment Area: Includes component cooling water and spent fuel pool	Auxiliary Building	Not Harsh
81	Main Steam Vault: Supports Main Steam, Main Feedwater, and Auxiliary Feedwater.	Auxiliary Building	Bounded
82	Mechanical Equipment Room	Auxiliary Building	No PRA
Lower Level	Primarily Circulating Water Pumps	Auxiliary Building	Not Harsh
Operating Deck	Fire Pumps (1 Diesel, 1 Electric) and Rotating Screens	Intake Structure	Harsh

TABLE 4 Auxiliary Steam System Area Groups			
Room	Description	Location	Group
Raw Water Vault	Safety-Related Raw Water Pumps and Associated Equipment	Intake Structure	Not Harsh

Group Definitions:

Not Harsh: Calculations indicate that breaks of the auxiliary steam system in these areas would not result in a harsh environment as defined by the licensee's design basis.

Bounded: Calculations indicate that breaks of the auxiliary steam system in these areas are bounded by more energetic failures. Therefore, all equipment in the area was previously qualified.

No PRA: No risk-significant equipment, as defined in the probabilistic risk assessment, is contained in these rooms. Therefore, regardless of qualification status, change in risk would be negligible.

Harsh: Calculations indicated that breaks of the auxiliary steam system in these areas would cause a harsh environment. Evaluation of the change in risk was quantified.

Auxiliary steam piping and components were installed in each of the 19 plant areas listed in Table 4. The licensee had failed to analyze these areas, and other equipment in the vicinity, for the environmental conditions that would result from a high-energy break of the auxiliary steam system. The analyst evaluated each of the four area groups from Table 4 as follows:

Not Harsh: The eleven areas listed in this group were evaluated by the licensee to assess the impact of a break of the auxiliary steam system. None of the areas in this group were determined to result in a harsh environment as described by the licensee's equipment qualification program. By definition, equipment design criteria at Fort Calhoun Station should result in plant components being able to continue to function normally provided the environment is not harsh. Therefore, the ΔCDF, given the performance deficiency, was negligible for components in areas in the "Not Harsh" group.

Bounded: Room 81 was the only area listed in this group. The licensee evaluated the impact of a break of the auxiliary steam system in this room. The harsh environment quantified in this analysis was determined to be bounded for temperature and humidity by the main steam and main feedwater line breaks previously analyzed. All equipment in Room 81 was properly qualified for harsh environments except for flooding, as discussed later and documented in Table 5. The analyst determined qualitatively that a break of the auxiliary steam system piping in Room 81 would not provide sufficient flooding to affect components not previously analyzed for submersion. Therefore, the ΔCDF, given the performance deficiency, related to auxiliary steam piping, was negligible for components in Room 81, the "Bounded" group.

No PRA: The four areas listed in this group were evaluated by the licensee to assess the impact of a break of the auxiliary steam system.

These areas were determined to result in a harsh environment following an auxiliary steam system piping break, as described by the licensee's equipment qualification program. However, the analyst noted that there was no equipment modeled in the licensee's probabilistic risk assessment in any of these areas. By definition, equipment that is not included in a properly developed probabilistic risk assessment is of low risk significance. As such, regardless of qualification status, the failure of equipment in these areas following a postulated break of the auxiliary steam system would not be risk-significant. Therefore, the ΔCDF, given the performance deficiency, was negligible for components in areas in the "No PRA" group.

Harsh: The three areas listed in this group were evaluated by the licensee to assess the impact of a break of the auxiliary steam system. All of the areas in this group were determined to result in a harsh environment, following a postulated break in the auxiliary steam system piping, as described by the licensee's equipment qualification program. The analyst provided an upper bound risk assessment for each of these areas as follows:

Room AB063: The analyst assessed the risk of an auxiliary steam line break in Auxiliary Building Room AB063, "Diesel Generator Room 1." The analyst noted that a high-energy line break in this room would not cause an initiator. According to Combustion Engineering Nuclear Power LLC, ST-2000-0627, the plant-wide frequency of a break of the auxiliary steam system would be approximately 6.44×10^{-4}/year for various rooms in the facility. As a bounding assumption, the analyst assumed that the failure frequency of the auxiliary steam system in Room AB063 (λ_{63}) would be no higher than 1×10^{-3}/year.

The analyst assumed that, given a postulated high-energy break of the auxiliary steam system, Diesel Generator 1 would be inoperable and the Technical Specification allowed outage time would be entered. Following the Technical Specification requirements, plant operators would shut down the reactor in 78 hours and cool down the reactor coolant system in another 30 hours. In order for the diesel generator to be demanded during these 108 hours, a loss of power would need to occur on the associated vital bus. The probability of a loss of offsite power occurring during the period ($P_{LOOP-108}$) was calculated to be 3.51×10^{-4}.

In accordance with Assumption 2, the exposure period (EXP) was the 1-year assessment period. The analyst then calculated the bounding ΔCDF (ΔCDF_{AB063}), by assuming a conditional core damage probability (CCDP) of 1.0 as follows:

$$\begin{aligned}\Delta CDF_{AB063} &= \lambda_{63} \ * \ P_{LOOP-108} \ * \ CCDP \ * \ EXP \\ &= 1 \times 10^{-3}/\text{year} \ * \ 3.51 \times 10^{-4} \ * \ 1.0 \ * \ 1.0 \text{ year} \\ &= 3.5 \times 10^{-7}\end{aligned}$$

Room AB064: The analyst assessed the risk of an auxiliary steam line break in Auxiliary Building Room AB064, "Diesel Generator Room 2." The analyst noted that a high-energy line break in this room would not cause an initiator. According to Combustion Engineering Nuclear Power LLC, ST-2000-0627, the plant-wide frequency of a break of the auxiliary steam system would be approximately 6.44 x 10^{-4}/year for various rooms in the facility. As a bounding assumption, the analyst assumed that the failure frequency of the auxiliary steam system in Room AB064 (λ_{64}) would be no higher than 1 x 10^{-3}/year.

The analyst assumed that, given a postulated high-energy break of the auxiliary steam system, Diesel Generator 2 would be inoperable and the Technical Specification allowed outage time would be entered. Following the Technical Specification requirements, plant operators would shut down the reactor in 78 hours and cool down the reactor coolant system in another 30 hours. In order for the diesel generator to be demanded during these 108 hours, a loss of power would need to occur on the associated vital bus. The probability of a loss of offsite power occurring during the period ($P_{LOOP\text{-}108}$) was calculated to be 3.51 x 10^{-4}.

In accordance with Assumption 2, the exposure period (EXP) was the 1 year assessment period. The analyst then calculated the bounding ΔCDF (ΔCDF_{AB064}), by assuming a conditional core damage probability (CCDP) of 1.0 as follows:

$$\begin{aligned}\Delta CDF_{AB064} &= \lambda_{64} \;*\; P_{LOOP\text{-}108} \;*\; CCDP \;*\; EXP \\ &= 1 \times 10^{-3}/\text{year} \;*\; 3.51 \times 10^{-4} \;*\; 1.0 \;*\; 1.0 \text{ year} \\ &= 3.5 \times 10^{-7}\end{aligned}$$

Intake Operating Floor: The analyst assessed the risk of an auxiliary steam line break in the Intake Structure operating floor. The analyst noted that a high-energy line break in this room would potentially cause a reactor trip, loss of functional screens, and loss of the fire pumps. According to Combustion Engineering Nuclear Power LLC, ST-2000-0627, the plant-wide frequency of a break of the auxiliary steam system would be approximately 44 x 10^{-4}/year for various rooms in the facility.

As a bounding assumption, the analyst assumed that the failure frequency of the auxiliary steam system on the Intake Structure Operating Deck (λ_{Intake}) would be no higher than 1 x 10^{-3}/year. The analyst assumed that, given a postulated high-energy break of the auxiliary steam system, the rotating screens would fail causing a loss of raw water. The analyst quantified the conditional core damage probability using the SPAR model, Version 8.20.

In accordance with Assumption 2, the exposure period (EXP) was the 1-year assessment period. The analyst then calculated the bounding ΔCDF (ΔCDF_{Intake}) as follows:

$$\Delta CDF_{Intake} = \lambda_{Intake} * CCDP * EXP$$
$$= 1 \times 10^{-3}/year * 7.09 \times 10^{-4} * 1.0\ year$$
$$= 7.1 \times 10^{-7}$$

Results for Section 2, "Auxiliary Steam System Piping Breaks"

The analyst determined that, because each of the area failure probabilities were selected to be independent of each other, the total bounding ΔCDF from the postulated failure of auxiliary steam system piping was the sum of the area frequencies. Therefore, the highest that the ΔCDF could be for this portion of the risk related to the performance deficiency was 1.4×10^{-6}.

Evaluation 3: High-Energy Line Break Area

The licensee identified five areas in the plant that contained high-energy piping that had not been properly evaluated for breaks. As a result, multiple risk-significant components were not properly protected or designed for the resulting harsh environment. The analyst reviewed each of the areas to identify equipment affected, initiating events of concern, initiating event frequencies and the conditional core damage probabilities. The evaluation of these areas and the risk characterization for each, are documented in Table 5.

Table 5
Harsh Environment Rooms
Bounding Risk Assessment Results

Location	Area Name	Scenario	Total ΔCDF
	(Affected Equipment)	Risk	
Auxiliary Building Room 12	Letdown Heat Exchanger Room		**5.36×10^{-7}**
	Main Feedwater	1.43×10^{-9}	
	Intersystem LOCA	5.35×10^{-7}	
Auxiliary Building Room 13	Lower Mechanical Penetration Room		**5.41×10^{-7}**
	Valves 438B and 438D	1.35×10^{-10}	
	Sump Recirculation	5.78×10^{-9}	
	Intersystem LOCA	5.35×10^{-7}	
Auxiliary Building Room 19	Compressor Room		**5.39×10^{-7}**
	SPAR Run:		
	- Loss of all 3-side Switchgear		
	- Failure of Pump FW-10		
	- Failure of Pump FW-6		

Auxiliary Building Room 69	Ventilation Equipment Area		**5.58 x 10^{-9}**
	SPAR Run:		
	- Loss of Component Cooling Water		
	- Bounding Frequency		
Auxiliary Building Room 81	Main Steam Vault		**1.82 x 10^{-6}**
	- Main Feedwater Break	1.26 x 10^{-6}	
	Loss of all Auxiliary Feedwater		
	- Main Steam Line Break	5.63 x 10^{-7}	
	Loss of Pumps FW-10 and FW-6		
Total Upper Bound ΔCDF:			**3.4 x 10^{-6}**

Initiating Event Frequency for High-Energy Line Break Areas

The licensee identified plant areas that had not been completely evaluated for the impacts of postulated high-energy line breaks. The five areas documented in Table 5 are those areas identified by the inspectors that had potentially significant equipment that was not properly qualified for the harsh environment that would occur following a postulated high-energy line break in the area.

The analyst determined the initiating event frequency for multiple scenarios involving high-energy line breaks. For each plant area of interest, the analyst used best available information to quantify the total frequency of a high-energy line break and/or identify a clear upper bound frequency.

Conditional Core Damage Probability for High-Energy Line Break Areas

For each scenario, the analyst quantified a bounding baseline and case conditional core damage probability using the site-specific SPAR model, Version 8.21. Each scenario documented in Table 5 is designated by the initiator used in the model, the component failures of interest, or the entire sequence used to quantify the scenario.

Upper Bound Results for High-Energy Line Break Areas

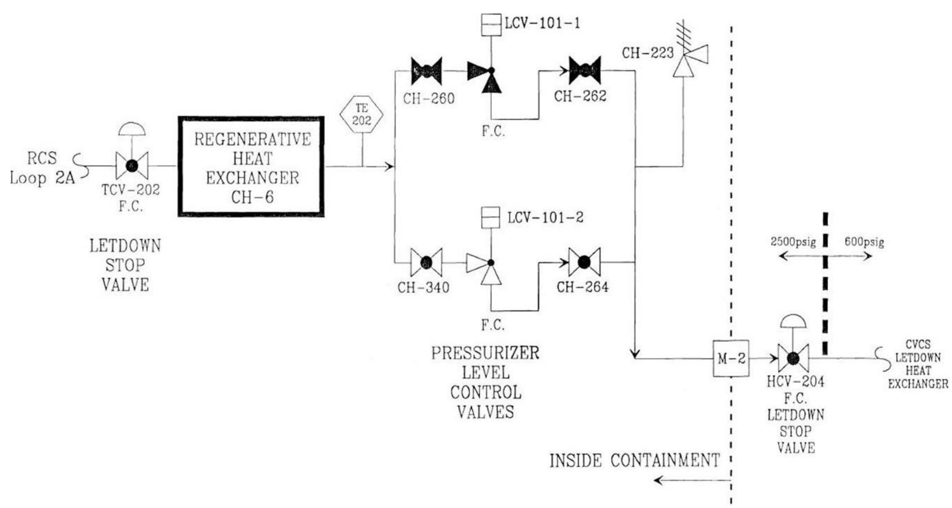
The analyst used a spreadsheet to maintain the detailed scenario specific inputs and results. The final, bounding results for each scenario and the total upper bound ΔCDF for each room are documented in Table 5.

Room 13:

The high-energy lines of interest in the Lower Mechanical Penetration Room were steam generator blowdown piping and the low-pressure portion of the letdown piping as shown in Figure 7. The analyst noted that the risk-significant equipment in the room included:

- Component Cooling Water Valves HCV-438B and HCV-438D
- Letdown Stop Valve HCV-204
- Effects from Impact to Motor-Control Centers in Corridor 4
    - Shutdown Cooling Isolation Valves HCV-347 and HCV-348
    - Sump Recirculation Valves HCV-383-3 and HCV-383-4

Figure 7
One-Line Diagram of Letdown System



The analyst evaluated three scenarios encompassing the change in risk from the performance deficiency in Room 13:

(1) Failure of Containment Sump Recirculation:

The analyst estimated the baseline high-energy line break frequency in Room 13 to be 2.77 x 10^{-6}/year from a breach of the blowdown system. However, the analyst noted that the licensee had determined they had been unable to inspect the socket welds in this area of the plant. As corrective action, the licensee replaced all applicable socket welds with butt welds. In order to account for the lack of ability to inspect the previous welds, the analyst increased the failure probability of the lines and used an initiating event frequency (λ_{13}) of 3.0 x 10^{-4}/year as a bounding assumption (Assumption 19).

Using this initiating event frequency, the analyst performed an assessment of the failure of the blowdown system piping in the room, assuming that the conditional core damage probability was bounded by a loss of main feedwater initiator. The resulting baseline ($CCDP_{Base4}$) was 4.75 x 10^{-6}.

Given the performance deficiency, a harsh environment would be created in Corridor 4 resulting in the loss of sump recirculation. The analyst quantified the case by analyzing a loss of main feedwater with the failure of Valves HCV-347, HCV 348, HCV-383-3, and HCV-383-4. The conditional core damage probability ($CCDP_{Corridor4}$) was 2.40×10^{-5}. The ΔCDF ($\Delta CDF_{Corridor4}$) was calculated as follows:

$$\begin{aligned} \Delta CDF_{Corridor4} &= \lambda_{13} * (CCDP_{Corridor4} - CCDP_{Base4}) * EXP \\ &= 3 \times 10^{-4}/year * (2.4 \times 10^{-5} - 4.75 \times 10^{-6}) * 1.0\ year \\ &= 5.8 \times 10^{-9} \end{aligned}$$

(2) Failure of Valves 438B and 438D

Using the model developed to analyze the loss of reactor coolant pump seal heat exchanger pipe, the analyst calculated the potential effect of a blowdown system pipe break in Room 13 on Valves HCV-438B and HCV-438D. The change in conditional core damage probability, assuming random initiators, was 4.5×10^{-7}. The analyst then multiplied this times the bounding frequency for a blowdown system piping break to obtain a ΔCDF of 1.4×10^{-10}.

(3) Letdown System Intersystem Loss of Coolant Accident

In addition to a random pipe failure, the analyst noted that a random failure of the operating letdown system control valve could result in overpressurization of the low pressure system piping and cause an intersystem loss of coolant accident. Such a sequence would occur as follows:

a) The operating letdown control valve (either Valve HCV-101-1 or HCV-101-2) randomly transfers open. The annual frequency of this event was about 2.1×10^{-2}/year from the licensee's probabilistic risk assessment;

b) Valve HCV-204, the letdown stop valve, fails to close on high flow (Probability about 9.5×10^{-4} per demand);

c) Temperature Control Valve TCV-202, a letdown stop valve, fails to close on high system temperature (Probability about 9.5×10^{-4} per demand plus common cause failure of TCV-202 and HCV-204 estimated at 2.5×10^{-5} per demand); and

d) Low pressure system piping, designed for 600 psig, fails when pressurized to near 2000 psig.

Upon failure of the system piping in Room 13, the analyst assumed that, given the performance deficiency, the harsh environment would fail Valve HCV-204, preventing operator intervention. The bounding ΔCDF for this postulated intersystem loss of coolant accident was 5.4×10^{-7}.

The total ΔCDF for Room 13 was the sum of the independent analyses above (5.4 x 10^{7}).

<u>Room 12</u>:

The Letdown Heat Exchanger Room contains letdown piping downstream of HCV-204 in Room 13, plus additional high-energy piping. The analyst noted that the affect that the performance deficiency would have on equipment in Room 12 could be bounded by the evaluation of the blowdown and letdown systems piping in Room 13. Therefore the total ΔCDF for Room 12 was 5.4 x 10^{-7}.

<u>Room 19</u>:

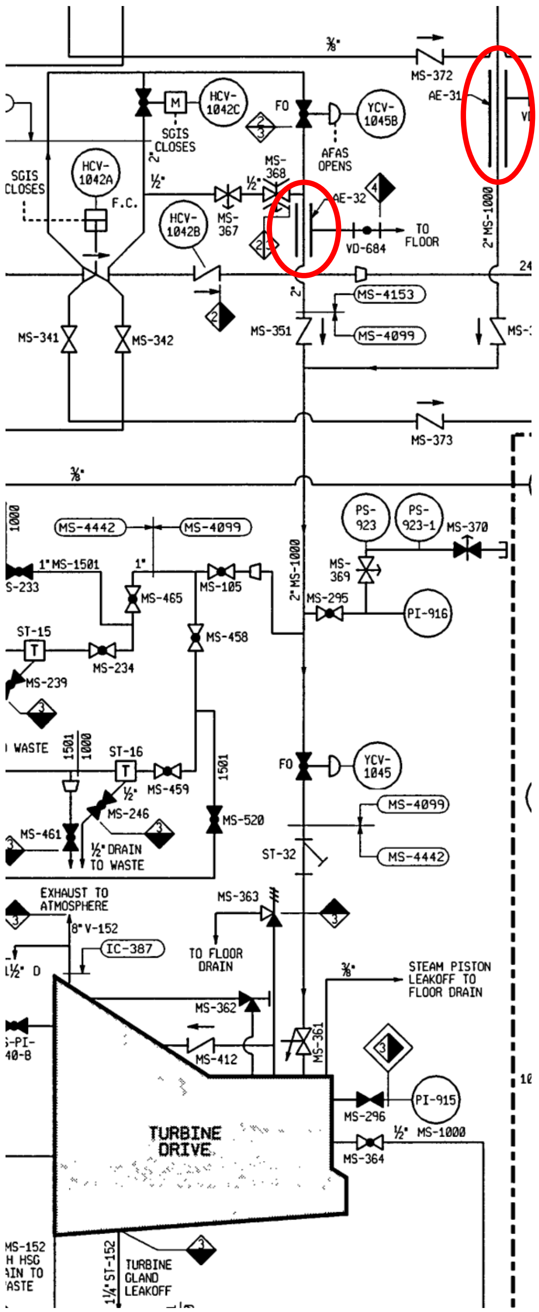
The primary high-energy line of concern in the Compressor Room is approximately 150 feet of steam supply piping to the Pump FW-10 turbine. The analyst noted that the risk-significant equipment in the room included:

- Auxiliary Feedwater Pump FW-10
- Auxiliary Feedwater Pump FW-6
- Instrument Air System Compressors
- Guard Pipe protecting Room 56 (See Figure 8)

The analyst noted that the primary effect of the performance deficiency was that the guard pipe, designed to protect Room 56E, East Switchgear Room, from a line break in Room 19 was degraded. The analyst assumed that steam in the guard pipe would inundate Room 56E in sufficient quantities to fail the 1A3 side electrical buses in the room.

The analyst reviewed simple calculations that indicated the air conditioning unit in Room 19 was large enough to remove the moisture from a steam line break in the room. Room 19 is a very large room and the air handling unit is positioned between the steam line and the instrument air compressors. As a result, the analyst assumed that the steam line break would not result in a loss of all instrument air to the plant.

Figure 8
One-Line Diagram of Steam Supply to Pump FW-10
Guard Pipes Indicated



The analyst reviewed a spreadsheet developed by the licensee, in accordance with the EPRI Technical Report 3002000079 method, for the 150 feet of steam piping. The calculated initiating event frequency (λ_{19}) was 8.43 x 10^{-5}/year.

Using the plant-specific SPAR model, the analyst quantified the conditional core damage probability for a failure of the Pump FW-10 steam supply line. The analyst assumed that a failure of the subject line would result in a transient and a failure of Auxiliary Feedwater Pump FW-10 from loss of its steam supply. The resulting baseline ($CCDP_{Base19}$) was 7.74×10^{-6}. The analyst then quantified the case, assuming that steam in Room 19 caused the failure of Auxiliary Feedwater Pump FW-6 and steam in the guard pipe inundated Room 56E in sufficient quantities to fail the 1A3 side electrical buses in the room. The resulting case value ($CCDP_{Room19}$) was 6.39×10^{-2}.

As a mitigating factor, the analyst noted that the pipe had an installed pressure transmitter that would alarm in the main control room following the low pressure from a line break. Abnormal Operating Procedure AOP-28 directed operators to isolate the line. As a bounding assumption, the analyst assumed that the operators would fail to isolate the line in accordance with plant procedures (P_{ISO}) with a probability of 1×10^{-1}.

The analyst calculated the ΔCDF (ΔCDF_{Room19}) as follows:

$$\begin{aligned}\Delta CDF_{Room19} &= \lambda_{19} \; * \; (CCDP_{Room19} - CCDP_{Base19}) \; * \; EXP \; * \; P_{ISO} \\ &= 8.43 \times 10^{-5}/\text{year} \; * \; (6.39 \times 10^{-2} - 7.74 \times 10^{-6}) \; * \; 1.0 \text{ year} \; * \; 0.1 \\ &= 5.4 \times 10^{-7}\end{aligned}$$

Room 69:

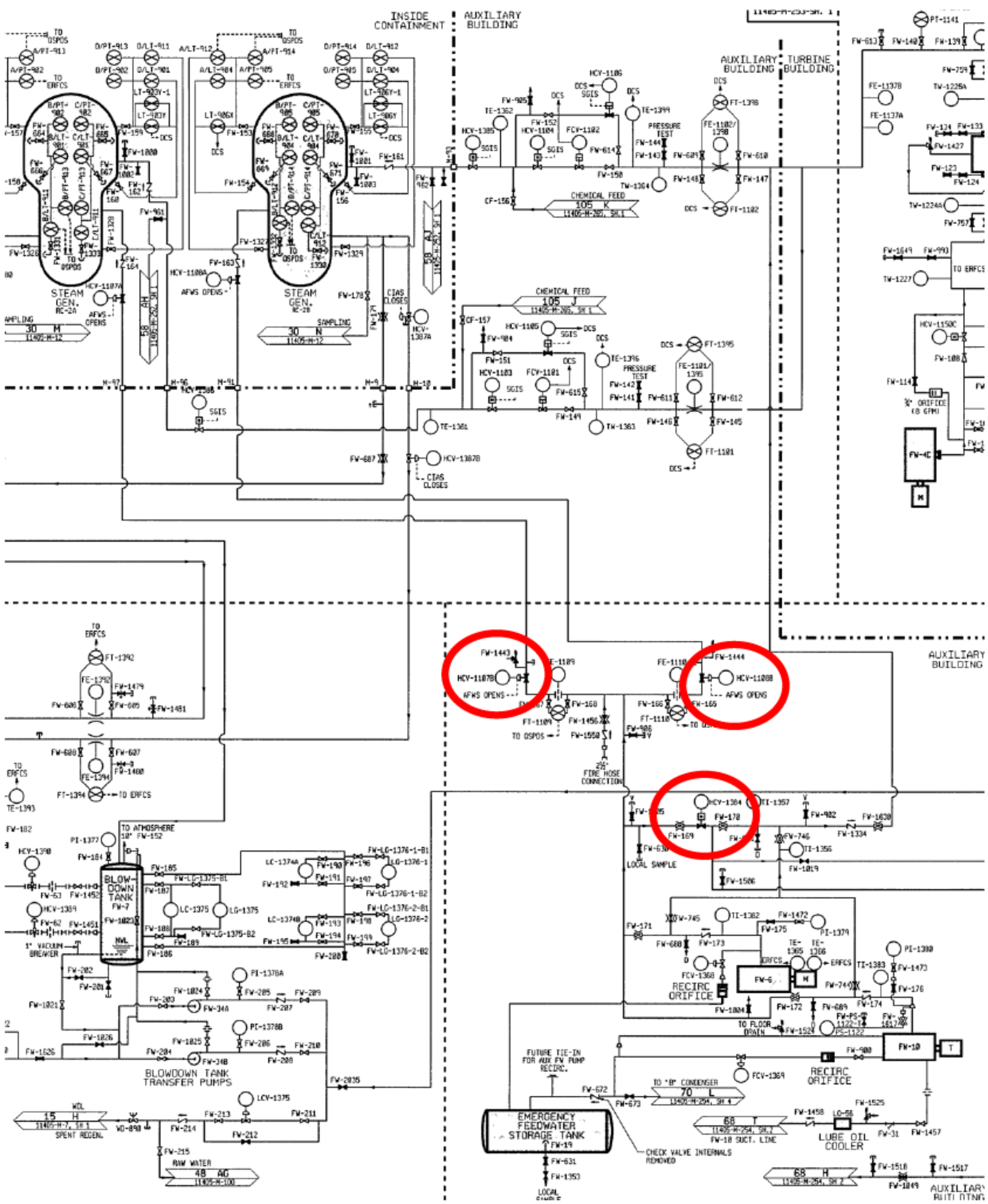
The Ventilation Equipment Area contains the component cooling water pumps, the system surge tank, and the spent fuel pool. The analyst determined that the worst case response to a high-energy line break in the area would be a loss of component cooling water. Using a bounding initiating event frequency of 3×10^{-4}/year (equivalent to a main steam line break outside containment), the analyst assumed that such a break would cause one additional loss of component cooling water initiator that would not have occurred without the performance deficiency. The analyst quantified the conditional core damage probability for a loss of component cooling water using the site-specific SPAR model. The result was 1.86×10^{-5}. This result was dominated by failure of the operators to provide backup component cooling water via the raw water system. The analyst then calculated the upper bound ΔCDF (5.58×10^{-9}) using a 1-year exposure period.

Room 81:

The major high-energy lines in the Main Steam Vault are system piping from main feedwater, main steam, auxiliary steam, and the steam supply to Auxiliary Feedwater Pump FW-10. The licensee had previously evaluated Room 81 for the effects of temperature, pressure, humidity, and radiation. All equipment in the room was qualified for these parameters. The licensee determined that large line breaks in the room could result in excessive flooding of the room beyond the design/qualified levels. The analyst determined that flooding could impact the function of the auxiliary feedwater supply Valves HCV-1107B and HCV-1108B, as well as the auxiliary feedwater crossover line isolation Valve HCV-1384 shown in Figure 9.

The analyst estimated the initiating event frequency for a large flood in Room 81 by assuming that any main steam line break or main feedwater line break could result in major flooding in the room. Using the frequencies of line breaks from the licensee's probabilistic risk assessment, the analyst calculated a total frequency (λ_{Break}) of 4.8 x 10^{-4}/year. The analyst noted that this was a bounding frequency, considering that these break frequencies included a wide range of break sizes, the smaller (and more frequent of which) would not cause a significant flood. This frequency was the sum of the frequency of a main steam line break ($\lambda_{BreakMS}$ = 3.0 x 10^{-4}/year) and ($\lambda_{BreakMF}$ = 1.8 x 10^{-4}/year).

Figure 9
One-Line Diagram of Auxiliary Feedwater System
Discharge Piping



The analyst used the plant-specific SPAR model to quantify conditional core damage probabilities for use in the evaluation. The following values were quantified:

- Loss of Main Feedwater ($CCDP_{Base}$) 4.75×10^{-6}
- Loss of Main and Auxiliary Feedwater ($CCDP_{AFW}$) 2.79×10^{-2}
- Loss of Main Feedwater and Pumps ($CCDP_{6\&10}$)1.88×10^{-3}
  - FW-10, Turbine Driven
  - FW-6, Motor Driven

The analyst noted that, given the performance deficiency, a main steam line break with the failure of Valves HCV-1107B, HCV-1108B, and HCV-1384 in the closed direction would result in a loss of Pumps FW-10, Turbine-Driven Auxiliary Feedwater Pump and FW-6, Motor-Driven Auxiliary Feedwater Pump. The ΔCDF for a main steam line break induced flood in Room 81 ($\Delta CDF_{MainSteam}$) over the 1-year exposure period (EXP) was bounded by the following:

$$
\begin{aligned}
\Delta CDF_{MainSteam} &= \lambda_{BreakMS} \ * \ (CCDP_{6\&10} - CCDP_{Base}) \ * \ EXP \\
&= 3.0 \times 10^{-4}/\text{year} \ * \ (1.88 \times 10^{-3} - 4.75 \times 10^{-6}) \ * \ 1 \text{ year} \\
&= 5.63 \times 10^{-7}
\end{aligned}
$$

The analyst noted that, given the performance deficiency, a main feedwater line break with the failure of Valves HCV-1107B, HCV-1108B, and HCV-1384 in the closed direction would result in a loss of Pumps FW-10, Turbine-Driven Auxiliary Feedwater Pump and FW-6, Motor-Driven Auxiliary Feedwater Pump. Additionally, the failure of the main feedwater line piping would fail Pump FW-54, Diesel-Driven Auxiliary Feedwater Pump for many scenarios. Given that Valves HCV-1107B and HCV-1108B fail open upon loss of air, to fail the valve closed would require a smart short of the valve terminal blocks. To fail the auxiliary feedwater system, both valves would have to fail closed. As a bounding assumption, the analyst assumed that the highest likelihood of a valve failing closed would be 50 percent of the flooding scenarios. Therefore, the probability of both Valves HCV-1107B and HCV-1108B failing closed following a flood of Room 81 (P_{Closed}) was calculated to be no higher than 2.5×10^{-1}.

The ΔCDF for a main feedwater line break induced flood in Room 81 ($\Delta CDF_{MainFeed}$) over the 1-year exposure period (EXP) was bounded by the following:

$$
\begin{aligned}
\Delta CDF_{MainFeed} &= \lambda_{BreakMF} \ * \ (CCDP_{AFW} - CCDP_{Base}) \ * \ P_{Closed} \ * \ EXP \\
&= 1.8 \times 10^{-4}/\text{year} \ * \ (2.79 \times 10^{-2} - 4.75 \times 10^{-6}) \ * \ 0.25 \ * \ 1 \text{ year} \\
&= 1.26 \times 10^{-6}
\end{aligned}
$$

The total ΔCDF for Room 81 was the sum of the independent analyses above (1.82×10^{-6}).

Results for Section 3, "High-Energy Line Break Area Evaluation"

The analyst determined that, because each of the five area failure probabilities were selected to be independent of one another, the total bounding ΔCDF from postulated pipe breaks in the subject areas was the sum of the area frequencies. Therefore, the highest that the ΔCDF could be for this portion of the risk related to the performance deficiency (as documented in Table 5) was 3.4×10^{-6}.

Conclusions

As discussed in Section 1, the best-estimate evaluation indicates that the ΔCDF from the air-operated valves with inappropriate elastomers was 4.1×10^{-6}. As discussed in Section 2, the upper bound risk resulting from auxiliary steam system piping failures was 1.4×10^{-6}. Finally, in Section 3, the analyst documented the upper bound risk from five previously unanalyzed areas in the plant as 3.4×10^{-6}. This results in a best-estimate ΔCDF of 4.1×10^{-6} and an upper bound of no higher than 8.9×10^{-6}. Therefore, the subject finding is of low to moderate safety significance (White).

(4) Sensitivity Analysis

The SRA performed a variety of uncertainty and sensitivity analyses on the results and modeling as shown below. The results confirm the recommended White finding.

Sensitivity Analysis 1 – Isolation of Intersystem Loss of Coolant Accident.

The analyst determined the sensitivity of the results to a range of operator failure probabilities. The analyst used the range of 5×10^{-2} to 2×10^{-1} for the basic event Out-Iso-Holds111. This provided a factor of 2 above and below the assumed value. Using this range, the analyst calculated the sensitivity of the evaluation to the selection of this human error probability. The ΔCDF range was 1.9×10^{-6} – 7.6×10^{-6} (White).

Sensitivity Analysis 2 – Initiation of Auxiliary Steam Line Break.

The analyst evaluated the effects of varying auxiliary steam line break frequencies to determine the sensitivity of the analysis to this assumption. The analyst reviewed the bounding assumptions applied and determined that the frequency of a steam line break could not be substantially higher than the 1×10^{-3}/year estimated. Auxiliary steam system operates at a pressure of 150 psig or less. Therefore, the likelihood of a steam line break causing a harsh environment is conditional. For the lower end of the range, the analyst used the Combustion Engineering Nuclear Power LLC, ST-2000-0627 plant-wide frequency of 6.44×10^{-4}/year for various areas throughout the plant. The range of ΔCDF was 4.6×10^{-7} – 1.4×10^{-6} (As an upper bound result, and combined with the best estimate risk, this supports the White finding).

Sensitivity Analysis 3 – Failure of Auxiliary Feedwater Injection Valves.

The analyst determined the sensitivity of the results to the selection of the failure probability for Valves HCV-1107B and HCV-1108B. To establish a range, the analyst first noted that the upper bound of the range was that the valves fail closed under all conditions. This is severely limiting, given the valves fail open on loss of air requiring a smart short to fail the valves closed. As a lower bound of the sensitivity, the analyst assumed the valves would fail open 1 time in 10 and that this conditional probability is independent for each valve. The range of ΔCDF was 6.1×10^{-7} – 5.6×10^{-6} (As an upper bound result, this supports the White finding).

(5) Contributions from External Events (Fire, Flooding, and Seismic)

This performance deficiency only impacts the risk of the plant to high-energy line breaks. No external event is postulated to cause a high-energy line break.

(6) Potential Risk Contribution from Large, Early Release Frequency

In accordance with the guidance in NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," most of the scenarios evaluated related to this finding would not involve a significant increase in risk of a large, early release of radiation because Fort Calhoun Station has a large, dry containment and the dominant sequences contributing to the ΔCDF did not involve either a steam generator tube rupture or an intersystem loss of coolant accident. However, two scenarios involved the effects of the performance deficiency on the risk of an intersystem loss of coolant accident.

The analyst noted that the scenarios reviewed that related to intersystem loss of coolant accidents took a long time to develop. For the dominant core damage sequences, core uncovery was predicted between 12 and 24 hours after transient initiation. This would have provided for effective evacuation of the close-in population prior to release. Therefore, while these ruptures would result in potentially large releases, the releases would not be early.

The analyst determined that the significance of this finding was considered to be core damage frequency-dominant, and the impact to large, early release frequency was negligible.

(7) Total Estimated ΔCDF

The total best estimate ΔCDF caused by this performance deficiency is the sum of the internal and external events ΔCDFs. This value was 4.1×10^{-6}. Additional scenarios impacting risk were evaluated using bounding analyses. The analyst determined that the total ΔCDF could be no higher than 8.9×10^{-6}. Therefore, this finding is of low to moderate safety significance (WHITE).

(8) Licensee's Risk Evaluation

The licensee did not have an independent evaluation of the overall risk associated with this performance deficiency. However, the licensee provided significant input to assist with determination of the high-energy line break (including environmental qualifications of air-operated valve elastomers) risk significance. Input included descriptions of high-energy line break scenarios and associated operator actions, detailed lists of components potentially subject to a harsh environment, and the baseline probabilistic risk assessment model results for auxiliary steam ruptures. Lengths of piping for high-energy systems were provided to assist with calculating initiating event frequencies.

The licensee provided a position paper on the performance of nitrile elastomers at high temperature, because some nitrile elastomers could be exposed to conditions beyond their design service conditions. The position paper included postulated failure probabilities for harsh environments.

Input provided by the licensee was both quantitative and qualitative. However, it was not integrated in such a way that it presented a conditional core damage probability or a conditional large, early release frequency representing the overall impact of high-energy line break issues.

The analysts took exception with some of the licensee's conclusions regarding nitrile elastomer performance under harsh conditions. The analyst also assigned higher failure probabilities to selected operator actions associated with high-energy line break accident scenarios. This was partially based on the judgment of the uncertainties in material fragilities and event durations.

(9) Summary of Results and Impact

The NRC's quantitative risk assessment was determined to represent a risk estimate in the "White" region. The White Finding is based on internal event initiated ΔCDF.

(c) Peer Review:

The analyst requested a peer review of this analysis from the Office of Nuclear Reactor Regulation, Division of Risk Assessment, PRA Operations and Human Factors Branch. As a result of this review, all peer reviewer comments were addressed and/or incorporated into the final detailed risk evaluation.

(d) References:

The analysts used the following generic references in preparing the risk assessment:

- NUREG/CR-5042, "Evaluation of External Hazards to Nuclear Power Plants in the United States"

- NUREG/CR-6883, “The SPAR-H Human Analysis Method.” August 2005
- NUREG-1842, “Good Practices for Implementing Human Reliability Analysis.” April 2005
- NUREG/CR-6595 Revision 1, “An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events.” October 2004
- INL/EXT-10-18533 Revision 2, “SPAR-H Step-by-Step Guidance.” May 2011
- “RASP Manual Volume 1 – Internal Events,” Revision 2.0 dated January 2013
- Risk Assessment of Operational Events, Volume 2 – “External Events,” Revision 1.01, January 2008
- NUREG/CR-1278, “Handbook of HRA with Emphasis on Nuclear Power Plant Applications,” August 1983
- NRC Inspection Manual Chapter 0609, “Significance Determination Process”

The analysts used the following plant specific references:

- Standardized Plant Analysis Risk model for Fort Calhoun Station, Versions 8.20 and 8.21
- EPRI Technical Report 3002000079, “Pipe Rupture Frequencies for Internal Flooding Probabilistic Risk Assessments,” Revision 3
- Licensee White Paper, “Performance of Nitrile Valve Elastomers at High Temperatures”
- Abnormal Operating Procedure AOP-28, “Auxiliary Feedwater System Malfunctions,” Revisions 15 and 18
- Emergency Operating Procedure EOP-03, “Loss of Coolant Accident”
- Emergency Operating Procedure EOP-20, “Functional Recovery Procedure”
- Figure 8.1-1, “Simplified One Line Diagram, Plant Electrical System, P & ID”
- Fort Calhoun Station Unit No. 1, Updated Safety Analysis Report
- Licensee Design Evaluation Elastomers A-155, “Temperature Ratings for Elastomers in Air Operated Valves”
- Licensee’s Event Tree, “I3Q Elastomer Event Tree 10-01-2013”
- Probabilistic Risk Assessment Fault Tree @ISLCVCS, “CVCS Letdown Line Outside Containment Overpressurizes,” dated August 20, 2014
- Drawing 11405-M-252, Sheet 1, “Flow Diagram Steam, P & ID, Revision 113
- Drawing 11405-M-253, Sheet 1, “Flow Diagram Steam Generator Feedwater and Blowdown, P & ID,” Revision 98
- Drawing 11405-M-253, Sheet Cov., “Composite Flow Diagram Steam Generator Feedwater and Blowdown, P & ID,” Revision 52
- Drawing CHDR 11405-A-5, “Primary Plant Ground Floor Plan, P & ID,” Revision 45
- Drawing 11405-A-7, “Primary Plant Intermediate & Operating Floor Plans, P & ID,” Revision 31

- Drawing 11405-A-8, “Primary Plant Operating Floor Plan, P & ID,” Revision 51
- Combustion Engineering Nuclear Power LLC, ST-2000-0627, “Fort Calhoun Station Unit 1, Recommendation for Closure of PRA Concern CCF 099-002,” Revision 001