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

March 19, 2014

EA-14-037

Lou 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 - NRC INTEGRATED INSPECTION REPORT NUMBER 05000285/2014002 AND NOTICES OF VIOLATIONS

Dear Mr. Cortopassi:

On February 15, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Fort Calhoun Station. On February 25, 2014, the NRC inspectors discussed the results of this inspection with Mr. Michael Prospero, Plant Manager, and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

During this inspection, the NRC staff examined activities conducted under your license as they relate to public health and safety with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of the inspection, the NRC has determined a Severity Level IV violation of NRC requirments occurred. Additionally, the NRC identified an issue that was evaluated under the risk significance determination process as having very low safety significance (green). The NRC also determined that a violation was associated with this issue.

These violations were evaluated in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

These violations are cited in the enclosed Notice and the circumstances surrounding them are described in detail in the subject inspection report. The violations are being cited in the Notice because one issue was repetitive in nature and the other issue involved the failure to restore compliance (or demonstrate objective evidence of plans to restore compliance) within a reasonable period of time after a violation is identified.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC's review of your response to the Notice will also determine whether further enforcement action is necessary to ensure your compliance with regulatory requirements.

Additionally, based on the results of the inspection, the NRC identified two additional Severity Level IV violations of NRC requirements and five findings evaluated under the risk significance determination process as having very low safety significance. The NRC determined that violations were associated with these issues, however, these violations are being treated as Non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violations or significance of these NCVs, 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 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 any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Michael Hay, Chief
Project Branch F
Division of Reactor Projects

Docket: 50-285
License: DPR-40

Enclosure:
NRC Inspection Report 05000285/2014002
w/Attachment: Supplemental Information

cc w/ encl: Electronic Distribution

Electronic distribution by RIV:
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SUNSI Rev Compl.	☑Yes ☐ No	ADAMS	☑Yes ☐ No	Reviewer Initials	MCH
Publicly Avail.	☑Yes ☐ No	Sensitive	☐Yes ☑ No	Sens. Type Initials	MCH
SRI:DRP/F	RI:DRP/F	SPE:DRP/F	PE:DRP/F	OE	C:DRP/F
JKirkland	JWingebach	NTaylor	CSmith	RBrowder	MHay
/RA/	/RA/	/RA/	/RA/	/RA/	/RA/
03/18/14	03/18/14	03/13/14	03/18/14	03/19/14	03/19/14

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket No: 50-285
License No: DPR-40
EA-14-037

During an NRC inspection conducted on August 26, 2013 through February 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 XVI, "Corrective Action," 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 nonconformances are promptly identified and corrected.
>
> Contrary to the above, between August 12, 2008 and November 24, 2013, the licensee failed to correct a condition adverse to quality. Specifically, actions were not taken to correct NRC-identified runout concerns in the containment spray system until these concerns were again raised by the NRC on July 18, 2013.

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

Pursuant to the provisions of 10 CFR 2.201, Omaha Public Power District is hereby required to submit a written statement or explanation 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 facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-14-037" and should include: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

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

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it 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). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 19th day of March, 2014

NOTICE OF VIOLATION

Omaha Public Power District
Fort Calhoun Station

Docket No: 50-285
License No: DPR-40
EA-14-037

During an NRC inspection conducted on August 26, 2013 through February 15, 2014, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR 50.73(a)(1), requires, in part, that the licensee submit a Licensee Event Report (LER) for any event of the type described in this paragraph within 60 days after the discovery of the event.
>
> Contrary to the above, between June 14 and July 2, 2013, the licensee failed to submit a LER for two events meeting the requirements for reporting specified in 10 CFR 50.73 within 60 days after the discovery of the event. Specifically, LERs 2013-101-0, "HPSI Pump Flow Imbalance," and 2013-017-0, "Containment Spray Pump Design Documents do not Support Operation in Runout," were submitted more than 60 days after the events were discovered.
>
> The NRC determined that this violation was repetive in nature as described in Paragraph 2.3.2(a)(3) of the NRC Enforcement Policy. A similar violation had been documented in NRC Inspection Report 2013008 dated July 16, 2013 (ML13197A261). That report included NCV 05000285/2013008-43, entitled "Untimely Submittal of Licensee Event Reports." The NCV documented nine examples of LERs that were submitted later than required by 10 CFR 73(a)(1).

This is a Severity Level IV violation.

Pursuant to the provisions of 10 CFR 2.201, Omaha Public Power District is hereby required to submit a written statement or explanation 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 facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; EA-14-037" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

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

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), and be accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it 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). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

Dated this 19th day of March, 2014

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000285
License:	DPR-40
Report:	05000285/2014002
Licensee:	Omaha Public Power District
Facility:	Fort Calhoun Station
Location:	9610 Power Lane Blair, NE 68008
Dates:	January 1 through February 15, 2014
Inspectors:	J. Kirkland, Senior Resident Inspector J. Wingebach, Resident Inspector N. Taylor, Senior Project Engineer W. Smith, Project Engineer W. Lyon, Senior Reactor Engineer M. Chambers, Physical Security Inspector A. Guzzetta, Reactor Systems Engineer M. Farnan, Mechanical Engineer A. Sallman, Senior Reactor Systems Engineer
Approved By:	Michael Hay, Chief, Project Branch F Division of Reactor Projects

SUMMARY

IR 05000285/2014002; 01/01/2014 – 02/15/2014; Fort Calhoun Station; integrated resident inspection report and Confirmatory Action Letter closeout items.

The inspection activities described in this report were performed between January 1, 2014, and February 15, 2014, by the resident inspectors at the Fort Calhoun Station, inspectors from the NRC's Region IV office, and technical support from headquarters staff. Nine findings are documented in this report. Seven findings were of very low safety significance (Green). All of these findings involved violations of NRC requirements and three of these violations were determined to be Severity Level IV violations under the traditional enforcement process. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, "Significance Determination Process." Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, "Components Within the Cross-Cutting Areas." Violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, "Reactor Oversight Process."

Cornerstone: Mitigating Systems

Green. A non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified involving the failure to translate the High Pressure Safety Injection (HPSI) pump design and runout characteristics to design documents such as the Updated Safety Analysis Report or design calculations. On June 21, 2013, the licensee completed Engineering Change 59874, which permanently installed flow-limiting orifices in the discharge line of each pump, effectively preventing HPSI runout conditions from occurring for all plant conditions.

This finding was more than minor because it adversely impacted the design control attribute of the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors reviewed NRC IMC 0609, Attachment 4, "Initial Characterization of Findings," Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power. As such, the inspectors determined the finding should be evaluated using the SDP in accordance with IMC 0609, "The Significance Determination Process (SDP) for Findings at-Power," Appendix A, Exhibit 2, "Mitigating Systems Screening Questions." The finding required a detailed risk evaluation because the high pressure safety injection system was inoperable for some of the large break loss of coolant accident scenarios (at reactor pressures less than 100 psi). A Region IV senior reactor analyst performed a bounding detailed risk evaluation. The change to the core damage frequency was 8E-8/year and, therefore, determined to be of very low safety significance (Green). The dominant core damage sequences included loss of coolant accidents where the high and low pressure safety injection systems failed during recirculation. The non-degraded low pressure safety injection system contributed to minimize the risk. The inspectors determined there was no cross-cutting aspect associated with this finding because events related to identification of needed procedures and specifications occurred in the 1970's and are not indicative of current performance. (Section 4OA3.2)

Green. Two examples of a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," were identified. The first example involved the failure to establish procedures or Technical Specifications to accomplish required HPSI injection flow balancing. The second example involved the failure to provide controls or testing to ensure that replacement parts for HPSI injection valves were suitable for the application and were capable of supporting the safety-related functions of the HPSI system. The licensee has since implemented Engineering Change 59874 which included throttling of the HPSI loop injection valves. This change was completed on August 20, 2013, restoring the original plant design and overcoming the configuration control errors introduced on three of the eight injection valves. Post-work testing for the completed modification included flow balance testing for the HPSI loop injection lines. The inspectors reviewed the results of this testing and determined that the UFSAR assumptions regarding balanced loop flows were adequately addressed by licensee corrective actions.

This finding was more than minor because it adversely impacted the design control attribute of the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors reviewed NRC IMC 0609, Attachment 4, "Initial Characterization of Findings," Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power. As such, the inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "The SDP for Findings at-Power," Appendix A, Exhibit 2, "Mitigating Systems Screening Questions." The inspectors answered "yes" to the question of "Does the finding represent a loss of system and/or function?" The inspectors determined the finding required a detailed risk evaluation per IMC 0609 Paragraph 6.0, because the operability of the high pressure safety injection system (both trains) was in question. A Region IV senior reactor analyst performed a detailed risk evaluation and determined the flow imbalance did not result in a loss of safety function. Since the high pressure safety injection system was capable of meeting the functional success criteria, there was no quantifiable change to the core damage frequency and therefore was determined to be of very low safety significance (Green). The inspectors determined there was no cross-cutting aspect associated with this finding because events related to identification of needed procedures and specifications occurred in the 1970's and are not indicative of current performance. Additionally, the errant replacement of parts of three HPSI injection valves occurred between 1993 and 2006, and are also not indicative of current performance. (Section 4OA3.4)

SLIV and Green. A Severity Level IV non-cited violation of 10 CFR 50.59, "Changes, Tests, and Experiments," and an associated Green finding was identified involving the failure to request a license amendment for a facility change that required a change to the Technical Specifications. This issue is also associated with a Green finding related to the licensee's failure to follow Procedure NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," and Procedure FCSG-23, "10 CFR 50.59 Resource Manual," both of which require submittal of a license amendment request prior to making a facility change that requires a change to Technical Specifications. The licensee initiated CR 2014-01029 on January 23, 2014, to document this violation and track corrective actions.

This performance deficiency was considered to be of more than minor safety significance because it was associated with the procedure quality attribute of the mitigating systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow station procedures for the 10 CFR 50.59 process caused the Technical Specifications to become insufficient to ensure that the limiting conditions for operation will be met. Using Inspection Manual Chapter 0609 Appendix G, Checklist 4, the inspectors determined that the finding did not result in the loss of any accident mitigation capability and did not require a quantitative risk assessment. This finding was determined to be of very low risk significance.

This performance deficiency was also determined to be subject to traditional enforcement because it impeded the regulatory process, in that the failure to submit a license amendment and add required surveillance testing was in violation of 10 CFR 50.59(c)(1)(i) and caused the NRC-approved Technical Specifications to be out of alignment with the safety analysis for the facility. This violation is associated with a finding that has been evaluated by the SDP and communicated with an SDP color reflective of the safety impact of the deficient licensee performance. The SDP, however, does not specifically consider the regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and finding using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated finding. This violation was determined to be a Severity Level IV violation, because it is consistent with the examples in Paragraph 6.1.d of the NRC Enforcement Policy. The finding had a cross-cutting aspect in the training aspect of the human performance cross-cutting area because the licensee's staff failed to understand and misapplied NRC generic guidance related to discovery of inadequate Technical Specifications [H.9]. (Section 4OA3.4)

Green. A non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" was identified involving the licensee's failure to complete a 10 CFR 50.59 screening that met the requirements of Procedure NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," Revision 37. The licensee's staff subsequently re-performed the 50.59 screening on November 29, 2013, and determined that a 10 CFR 50.59 evaluation was required. The NRC staff reviewed the 10 CFR 50.59 screening and evaluation and determined that they had been properly performed, and that a license amendment request was not required prior to implementation of the activity. The licensee documented this procedural violation in CR 2014-01357 on January 29, 2014.

This performance deficiency was considered to be of more than minor safety significance because it was associated with the design control attribute of the mitigating systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow station procedures for the 10 CFR 50.59 process prevented the licensee's staff from evaluating the adverse impacts of the change on the facility. Using Inspection Manual Chapter 0609 Appendix G, Checklist 4, the inspectors determined that the finding did not result in the loss of any accident mitigation capability and did not require a quantitative risk assessment. This finding was determined to be of very low risk significance. The inspectors determined that this finding had a cross-cutting aspect of conservative bias in the human performance area, because the licensee's staff ensured that the proposed design change was safe in order to proceed rather than unsafe to stop [H.14]. (Section 4OA3.8)

Green. Several examples of a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," were identified involving the failure to ensure the adequacy of the anchorage for several raw water system and containment spray system pipe supports. Specifically the anchorage design was non-conservative with respect to the design basis requirements. The licensee entered these issues into the corrective action program as CR 2013-05304 and performed an operability determination as immediate actions. Long term actions to resolve the errors in the calculations are documented in the condition report.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of the containment spray system and raw water system. Using Inspection Manual Chapter 0609, Attachment 4 "Initial Characterization of Findings," and Appendix A "The Significance Determination Process (SDP) for findings at-power," both dated 6/19/12, the inspectors determined the performance deficiency affected the mitigating systems cornerstone and screened to Green because the finding affected the design and qualification of a mitigating component but remained operable. The inspectors used the at-power SDP because the condition existed since construction and while the plant was predominantly at power. The inspectors determined there was no cross-cutting aspect associated with this finding because the calculations were from the 1980's and therefore were not reflective of current performance. (Section 4OA5.1)

Green. A non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified involving the failure to ensure the adequacy of the U-bolts for containment air cooler pipe supports VAS-1 and VAS-2. Specifically the U-bolt design was non-conservative with respect to the design basis requirements. The licensee entered these issues into the corrective action program as CR 2013-03722. The licensee revised the calculation to support operability. In addition, the licensee generated engineering change EC59570 to fix the degraded VAS-1 and VAS-2 supports.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of several safety injection tank valves. Specifically, the one-directional U-bolts for VAS-1 and VAS-2 are not designed to withstand two-directional loading and the condensate drain piping line has the potential to adversely impact the safety injection tank discharge isolation valves HCV-2934 and HCV-2974 during a design basis event. The licensee updated calculation FC05918 and provided an operability evaluation to address the degraded condition. The inspectors reviewed the information and did not find any issues. Using Inspection Manual Chapter 0609, Attachment 4 "Initial Characterization of Findings," and Appendix A "The Significance Determination Process (SDP) for findings at-power," both dated June 19, 2012, the inspectors determined performance deficiency affected the mitigating systems cornerstone and screened to Green because the finding affected the design and qualification of a mitigating SSC but remained operable. The inspectors used the at-power SDP because the condition existed since construction and while the plant was predominantly at power. The inspectors determined there was no cross-cutting aspect associated with this finding because the calculation was from the 1980s, and therefore was not reflective of current performance. (Section 4OA5.2)

Cornerstone: Barrier Integrity

Green. A cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified involving the failure to take timely corrective action for a condition adverse to quality. Specifically, the licensee failed to restore compliance following NRC identification of the licensee's failure to correct a runout condition of the containment spray system (CS) documented in NCV 05000285/2008003-05, in August 2008. Licensee corrective actions to correct the issue included completion of an analysis of containment spray pump operation during the main steam line break (MSLB) event; revision of CS design documentation; analysis of motor performance by an electrical vendor; and completion of a temporary modification to throttle the CS pump discharge valves to provide additional system resistance preventing pump runout. Future corrective actions include a permanent design change to prevent CS pump runout. The licensee initiated CR 2014-02242 on February 19, 2014, to document this failure to restore compliance.

This finding was more than minor because it adversely impacted the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events. The inspectors reviewed NRC IMC 0609, Attachment 4, "Initial Characterization of Findings", Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power and should be evaluated using the Significance Determination Process in accordance with IMC 0609, "The Significance Determination Process (SDP) for Findings at-Power," Appendix A, Exhibit 3, "Barrier Integrity Screening Questions." The inspectors determined that the finding did not represent an actual open pathway in containment or containment isolation logic, nor did the finding represent an actual reduction in the function of containment hydrogen igniters. Based on the guidance in the Exhibit 3 checklist the inspectors determined that the finding was of very low safety significance.

The inspectors determined that the finding had a cross-cutting aspect of avoiding complacency in the human performance area, because the licensee's staff failed to recognize latent issues even while expecting successful outcomes [H.12]. (Section 4OA3.8)

Other Findings and Violations

SL-IV. A Severity Level IV non-cited violation of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems (ECCS) for light-water nuclear power reactors," was identified involving the failure to submit a report within 30 days of discovery of a significant change in the application of the ECCS model that affected the peak cladding temperature. The licensee submitted the required 10 CFR 50.46 report late on September 20, 2013 (ML13266A108). This report was subsequently reviewed by the NRC staff date October 2, 2013, and determined to be acceptable. The NRC staff determined that while the configuration change to the HPSI system resulted in a higher peak cladding temperature, it is within the regulatory requirements of 10 CFR 50.46(b)(1). The licensee initiated CRs-2014-00674 and 2014-01356 to address issuance of the late report.

This performance deficiency was determined to be subject to traditional enforcement because it impeded the regulatory process, in that the failure to submit a timely report of significant ECCS analytical changes prevented the NRC technical staff from independently evaluating the potential safety implications of reductions in safety injection flow into the reactor during an accident. This violation was determined to be a Severity Level IV violation because it is consistent with the examples in Paragraph 6.9.d of the NRC Enforcement Policy. Because this violation is subject to traditional enforcement, no cross-cutting aspects have been assigned. (Section 4OA3.2)

SL-IV. Two examples of a cited Severity Level IV violation of 10 CFR 50.73, “Immediate Notification Requirements for Operating Nuclear Power Reactors,” were identified involving the failure to submit a required licensee event report (LER) within 60 days following discovery of an event requiring a report. In the first example, LER 2013-010-0 was submitted on July 2, 2013, seventy-nine days after the flow imbalance was observed by the licensee’s staff. In the second example, LER 2013-017-0 was submitted to the NRC on December 27, 2013, 62 days after the event date on the licensee’s reportability evaluation and sixty-six days after a condition report documented the reportable condition. The licensee initiated CR 2014-01358 on January 29, 2014 to document this repetitive violation.

The violation was evaluated using Section 2.2.4 of the NRC Enforcement Policy, because the failure to submit a required LER may impact the ability of the NRC to perform its regulatory oversight function. As a result, this violation was evaluated using traditional enforcement. In accordance with Section 6.9(d)(9) of the NRC Enforcement Policy, this violation was determined to be a Severity Level IV violation. The inspetors determined that a cross-cutting aspect was not applicable to this performance deficiency because the failure to make a required report was strictly associated with a traditional enforcement violation. (Section 4OA3.4)

PLANT STATUS

The plant began the reporting period at 100% power. On January 9, 2014, the plant shutdown in accordance with Technical Specification 2.0.1 because an intake structure river sluice gate would not close. Following repairs, the plant reached citicality on January 12, 2014, and was manually tripped shortly thereafter due to a control element assembly that would not move. Following repairs the plant started up on January 13, 2014, and reached 100% power on January 15, 2014, where it remained for the duration of the inspection period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness to Cope with External Flooding

a. Inspection Scope

On January 8, 2014, the inspectors completed an inspection of the station's readiness to cope with external flooding. After reviewing the licensee's flooding analysis, the inspectors chose one plant area that was susceptible to flooding:

- Intake Structure, due to failure of sluice gates

The inspectors reviewed plant design features and licensee procedures for coping with flooding. The inspectors walked down the selected areas to inspect the design features, including the material condition of seals, drains, and flood barriers. The inspectors evaluated whether credited operator actions could be successfully accomplished.

These activities constituted one sample of readiness to cope with external flooding, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors performed partial system walk-downs of the following risk-significant systems:

- January 6, 2014, Auxiliary Building Ventilation

The inspectors reviewed the licensee's procedures and system design information to determine the correct lineup for the systems. They visually verified that critical portions of the systems were correctly aligned for the existing plant configuration.

These activities constituted one partial system walk-down sample as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors evaluated the licensee's fire protection program for operational status and material condition. The inspectors focused their inspection on two plant areas important to safety:

- January 28, 2014, Room 13, Mechanical Penetration Area, Fire Area 13

- January 28, 2014, Room 18, Component Cooling Heat Exchanger Area, Fire Area 33

For each area, the inspectors evaluated the fire plan against defined hazards and defense-in-depth features in the licensee's fire protection program. The inspectors evaluated control of transient combustibles and ignition sources, fire detection and suppression systems, manual firefighting equipment and capability, passive fire protection features, and compensatory measures for degraded conditions.

These activities constituted two quarterly inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

.2 Annual Inspection

a. Inspection Scope

On February 4, 2014, the inspectors completed their annual evaluation of the licensee's fire brigade performance. This evaluation included observation of one announced fire drill. During this drill, the inspectors evaluated the capability of the fire brigade members, the leadership ability of the brigade leader, the brigade's use of turnout gear and fire-fighting equipment, and the effectiveness of the fire brigade's team operation. The inspectors also reviewed whether the licensee's fire brigade met NRC requirements for training, dedicated size and membership, and equipment.

These activities constituted one annual inspection sample, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11)

.1 Review of Licensed Operator Requalification

a. Inspection Scope

On February 11, 2014, the inspectors observed simulator training for an operating crew. The inspectors assessed the performance of the operators and the evaluators' critique of their performance.

These activities constitute completion of one quarterly licensed operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

On January 22, 2014, the inspectors reviewed a risk assessment performed by the licensee prior to to performing a maintenance run on Diesel Generator 1 and the risk management actions taken by the licensee in response to the elevated risk.

The inspectors verified that this risk assessment was performed timely and in accordance with the requirements of 10 CFR 50.65 (the Maintenance Rule) and plant procedures. The inspectors reviewed the accuracy and completeness of the licensee's risk assessment and verified that the licensee implemented appropriate risk management actions based on the result of the assessment.

Additionally, on February 12, 2014, the inspectors observed portions of one emergent work activity that had the potential to affect the functional capability of mitigating systems. This activity involved the failure of the turbine driven auxiliary feedwater pump steam admission Valve YCV-1045.

The inspectors verified that the licensee appropriately developed and followed a work plan for these activities. The inspectors verified that the licensee took precautions to minimize the impact of the work activities on unaffected structures, systems, and components (SSCs).

These activities constitute completion of two maintenance risk assessments and emergent work control inspection samples, as defined in Inspection Procedure 71111.13

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed three operability determinations that the licensee performed for degraded or nonconforming structures, systems, or components (SSCs):

- January 20, 2014, operability determination of the raw water piping, due to a leak downstream of heat exchanger AC-1A
- February 3, 2014, operability determination of auxiliary steam to the intake structure
- February 13, 2014, operability determination of flow control valve FCV-1369 (FW-10 recirculation valve), due to non essential parts

The inspectors reviewed the timeliness and technical adequacy of the licensee's evaluations. Where the licensee determined the degraded SSC to be operable, the inspectors verified that the licensee's compensatory measures were appropriate to provide reasonable assurance of operability. The inspectors verified that the licensee had considered the effect of other degraded conditions on the operability of the degraded SSC.

These activities constitute completion of three operability and functionality review samples, as defined in Inspection Procedure 71111.15.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed two post-maintenance testing activities that affected risk-significant SSCs:

- January 30, 2014, Post-maintenance testing following the overhaul of the Diesel Auxiliary Feedwater Pump FW-54

- January 10, 2014, Post-maintenance testing Hot Leak Check following mechanical penetration M-45 piping swagelock replacement

The inspectors reviewed licensing- and design-basis documents for the SSCs and the maintenance and post-maintenance test procedures. The inspectors observed the performance of the post-maintenance tests to verify that the licensee performed the tests in accordance with approved procedures, satisfied the established acceptance criteria, and restored the operability of the affected SSCs.

These activities constitute completion of two post-maintenance testing inspection samples, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed five risk-significant surveillance tests and reviewed test results to verify that these tests adequately demonstrated that the SSCs were capable of performing their safety functions:

In-service tests:
- January 29, 2014, AC-10C Raw Water Pump Quarterly Inservice Test, OP-ST-RW-3021

Reactor coolant system leak detection tests:
- February 4, 2014, Manual leak rate calculation

Other surveillance tests:

- January 23, 2014, Quarterly functional test of Power Range Safety Channels A/B/C/D, IC-ST-RPS-0002/3/4/5

- February 12, 2014, Operability Test of instrument air valve IA-YCV-1045-C and Close Stroke Test of YCV-1045, IC-ST-IA-3009

- February 14, 2014, Auxiliary Feedwater Pump FW-10, Steam Isolation Valve, and Check Valve Tests, OP-ST-AFW-3011

The inspectors verified that these tests met technical specification requirements, that the licensee performed the tests in accordance with their procedures, and that the results of the test satisfied appropriate acceptance criteria. The inspectors verified that the licensee restored the operability of the affected SSCs following testing.

These activities constitute completion of five surveillance testing inspection samples, as defined in Inspection Procedure 71111.22.

b. <u>Findings</u>

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA2 Problem Identification and Resolution (71152)

.1 <u>Routine Review</u>

a. <u>Inspection Scope</u>

Throughout the inspection period, the inspectors performed daily reviews of items entered into the licensee’s corrective action program and periodically attended the licensee’s condition report screening meetings. The inspectors verified that licensee personnel were identifying problems at an appropriate threshold and entering these problems into the corrective action program for resolution. The inspectors verified that the licensee developed and implemented corrective actions commensurate with the significance of the problems identified. The inspectors also reviewed the licensee’s problem identification and resolution activities during the performance of the other inspection activities documented in this report.

b. <u>Findings</u>

No findings were identified.

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 <u>(Closed) LER 05000285/2012-013-00</u>: Inadequate Calculation of Uncertainty Results in a Technical Specification Violation

Technical Data Book Procedure (TDB)-III.40, "Technical Specification Required SIRWT Levels," lists the administrative requirements to maintain the Technical Specification (TS) required Safety Injection Refueling Water Tank (SIRWT) levels. The required SIRWT level for TS 2.3 accounts for instrument uncertainty, as described in the basis for TS 2.3. However, the required SIRWT levels listed in TDB-III.40 for TS 2.2.7 and 2.2.8 do not account for instrument uncertainty. Therefore, the TS described levels in TS 2.2.7 and 2.2.8 did not adequately account for SIRWT instrument level uncertainty. As a result, using the levels described in TDB-III.40 for compliance with TS 2.2.7 and 2.2.8 was non-conservative.

The causal analysis (2011-9956) concluded that there was inadequate/incomplete procedural guidance for developing Administrative Limits used to protect TS Limits. This includes guidance for understanding how to evaluate and apply uncertainties when developing TS Administrative Limits.

The licensee has revised procedures to include guidance on the development of new Technical Specification limits and the associated administrative limits. The licensee performed an extent of condition based on criteria in RG 1.97, Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants.

This Licensee Event Report is Closed.

.2 <u>(Closed) Licensee Event Report 05000285/2013-003-01:</u> Calculations Indicate the HPSI Pumps will Operate in Run-out During a DBA

a. <u>Inspection Scope</u>

On January 30, 2013, the licensee identified that design basis calculations indicated that the high pressure safety injection pumps would operate in a run out condition during postulated accident conditions. The licensee issued Revision 0 of the LER to report that this represented an unanalyzed condition, and that it was also an event or condition that could have prevented the fulfillment of the safety function of the HPSI system.

The preliminary causal analysis identified that the cause of the condition was that the station had failed to obtain vendor technical information on HPSI pump performance in a 10 CFR 50, Appendix B, quality assurance validated format. Corrective actions identified in the LER included revising procedures to prevent HPSI operation in runout; design changes to prevent HPSI operation in runout; and improving engineering guidance related to review of vendor information and documentation of engineering evaluations.

On November 27, 2013, the licensee submitted Revision 01 to the LER to update the cause and corrective actions taken for the condition.

The inspectors reviewed both revisions of the LER, and identified a number of observations and findings as described later in this report.

This Licensee Event Report is closed.

b. Review of OPPD Report "30-Day Report of a Significant Change in the Loss-of-Coolant Accident (LOCA)/Emergency Core Cooling System (ECCS) Models Pursuant to 10 CFR 50.46

Due to a deficiency associated with high pressure safety injection (HPSI) pump runout, the licensee determined that a physical plant modification was required involving installation of flow orifices to the HPSI discharge lines. The installation of these orifices affected HPSI flow rate, which changed the emergency core cooling system (ECCS) performance that is predicted using an evaluation model pursuant to the requirements of 10 CFR 50.46.

The inspectors reviewed the licensee's report which was submitted to the NRC staff on September 20, 2013, (ADAMS Accession number ML13266A108), per the requirements of 10 CFR 50.46(3)(ii). The report included evaluation of the HPSI flow reduction for both the Large Break Loss of Coolant Accident (LBLOCA) and Small Break Loss of Coolant Accident (SBLOCA).

For the evaluation of LBLOCA, the licensee reported that the reduction in HPSI flow had no impact on the predicted peak cladding temperature (PCT). The PCT for LBLOCA continues to be 1581 degrees Fahrenheit. The inspectors observed that HPSI is a system primarily designed to mitigate the effects of small break LOCAs, and did not identify any issues with this estimate.

The licensee estimated the effect of HPSI flow reduction on the SBLOCA analysis, and determined that the limiting break size decreased from a 3.5 inch diameter break to a 3.0 inch diameter break. The HPSI flow reduction also caused an increase in PCT of 309 degrees Fahrenheit. The resulting PCT for SBLOCA is 1746 degrees Fahrenheit. The inspectors determined that the revised PCT for the SBLOCA analysis reflects that the licensee considered, in its estimate, both the effect of the change on the predicted PCT for the limiting break size, and the potential for a new break size to be more limiting. The licensee's estimate also indicates that the estimated PCT remains below the 2200 °F acceptance criterion contained at 10 CFR 50.46(b)(1).

The inspectors did not identify any issues of significance related to the technical content of the 10 CFR 50.46 report. A violation was identified regarding the timeliness of this report, as discussed in section 4OA3.2.d.1 of this report.

c. Review of Emergency Core Cooling System Performance

A review of Emergency Core Cooling System (ECCS) design and performance was conducted by staff from the Reactor Systems Branch (SRXB) in the Office of Nuclear Reactor Regulation (NRR). The review included an audit of High Pressure Safety

Injection (HPSI) pump operability, containment spray (CS) pump operability, vortex issues, and void transport characteristics.

HPSI Pump Characteristics

A historical OPPD document was reviewed which listed developed head data for the HPSI 2A, 2B, and 2C pumps as a function of flow rate. Recent pump vendor (Sulzer Pumps, Inc.) analyses were reviewed which addressed expected degradation due to wear by assuming that internal clearances may be postulated to increase by multiples of 1.5 and 2.0 applied to the nominal design clearances. Analysis results were determined to be reasonable and the methodology appears to have been successfully applied by Sulzer for other applications.

The original seal water cyclone separators did not have sufficient flow to provide self-cleaning and were replaced. Recent evaluations of the replaced separators established that the seal water system will operate acceptably.

HPSI Pump Runout Control

The licensee's 2013 modification to the HPSI system acceptably limited HPSI pump flow rate to less than 450 gpm. This was accomplished by inserting orifices in the pump discharge pipes followed by testing that showed that the maximum flow rate occurred with HPSI Pump 2B at 402 gpm with no flow in the mini-flow lines. Historical information acceptably showed that open miniflow lines would increase runout flow rate by about 2 gpm, a negligible effect.

Orifice installation affected predicted ECCS evaluation model performance pursuant to the requirements of 10 CFR 50.46. This was addressed by the licensee consistent with the requirements of 10 CFR 50.46(3)(ii). The licensee reported that there was no impact on the predicted peak cladding temperature (PCT) for the large break loss-of-coolant accident (LBLOCA) and that PCT for the small break loss-of-coolant accident (SBLOCA) increased by 309 °F to 1746 °F. Predicted PCTs remained below the 2200 °F acceptance criterion contained at 10 CFR 50.46(b)(1). SRXB did not identify any issues of significance.

Containment Spray (CS) Pump Runout Control

The CS pumps were recognized as subject to runout for two scenarios and the licensee elected to address this issue by throttling the discharge valves to limit flow rate. Containment aspects were found acceptable by the NRR Containment & Ventilation Branch (SCVB) and valve characteristics were addressed by the Division of Engineering Mechanical and Civil Engineering Branch and found acceptable. SRXB's assessment of pump and motor issues is covered in the following paragraph.

The licensee used PROTO-FLO software to conclude that runout would be controlled by changing flow rate from 1885 to 1500 gpm and from 3770 to 2800 gpm for the single pump and two pump operating conditions, respectively. This was determined to be achieved if each pump discharge valve was throttled to achieve a flow rate of

2515 ± 25 gpm in a lineup where one CS pump draws from and recirculates back to the Safety Injection Refueling Water Tank (SIRWT). 43 cases were analyzed by PROTO-FLO plus another 10 cases to tune the code. SRXB determined that PROTO-FLO acceptably calculated flow behavior. SRXB also determined that flow rate could be acceptably controlled by the number of valve turns that correlated to calculated valve opening.

SIRWT Draining, Vortex, and Void Movement Considerations

The SIRWT is a 25 ft by 100 ft rectangular tank with two ECCS 19.25 inch inside diameter suction lines at one end. A cruciform vortex suppresser that extends into the tank is installed in the entrance to each suction line. The SRXB inspectors performed an exhaustive review of previous modeling of the SIRWT performance by a vendor, Fauske & Associates. The inspectors noted that the analysis performed by Fauske & Associates, and accepted by OPPD, contains a number of conservative as well as non-conservative errors. The licensee documented the inspector's observations in CRs 2013-21824 and 2013-21936. The licensee performed an immediate operability determination which demonstrated that the cumulative impact of the errors did not threaten the safety function of the SIRWT or the associated ECCS systems. The inspectors reviewed this operability determination and concluded that it acceptably addressed the inspector's concerns. The licensee also assigned several corrective actions to update the affected analyses. Lastly, the licensee entered Action 2 from CR 2013-21936 into the Performance Improvement Integrated Matrix (PIIM 2013-0086) to track the licensee's response to the inspector's observations prior to startup from the next refueling outage.

Measurement of Flow Rate

The licensee documented inaccuracies in the installed HPSI flow rate instrumentation that required installation of temporary ultrasonic flow rate meters (UFMs). The inspectors determined that the UFMs provided accurate indication of flowrate. The inspectors also noted that the installed instrumentation was of sufficient accuracy to support use by operations during emergency conditions, but the inaccuracies prevented appropriate flow indications for periodic pump testing as required by Technical Specifications.

Water Hammer

Fauske described an experimental and analysis methodology program to assess water hammer. The program showed that: (1) the gas void fraction for the initial stratified gas-water configuration is essentially preserved during the water hammer event, (2) the peak water hammer pressure is determined by the initial gas pressure and volume, the pump shutoff head and whether the system is flushed before the test conditions are established, (3) the peak force generated by the gas-water water hammer event is determined by the peak pressure and the rate of rise of the water hammer pressurization, (4) if the system piping includes a swinging check valve, the closure induced by the water hammer event can cause subsequent forces, in both axial directions (upstream and downstream), that are larger than the water hammer induced force, and (5) the peak forces are a function of both the piping configuration and the initial gas volume.

The licensee provided a water hammer evaluation of voids in suction piping. The evaluation assumed that the moving gas/water column would instantaneously encounter a rigid wall that corresponded to the HPSI suction location in an approach similar to that provided by Fauske. There appear to be no cases where water hammer due to compression of gas voids has caused actual pipe breaks. Therefore, SRXB judged that water hammer is not of significant concern with respect to HPSI operation.

A violation was identified regarding the design control attributes of this inspection, as discussed in Section 4OA3.2.d of this report.

d. Findings

i. Failure to Make Required 10 CFR 50.46 Report Within Required Time

Introduction. The inspectors identified a SLIV non-cited violation of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," for the licensee's failure to submit a report within 30 days of discovery of a significant change in the application of the ECCS model that affected the peak cladding temperature.

Description. 10 CFR 50.46(a)(3)(i) states, in part, that each licensee shall estimate the effect of any change in the application of an ECCS cooling evaluation model, to determine if the change is significant. A change is considered significant if it results in a calculated peak fuel cladding temperature different by more than 50° F from the calculation of record. Paragraph (ii) requires that any significant change be reported within 30 days to the NRC staff. 10 CFR 50.46(b)(1) provides an upper limit of 2200°F for maximum fuel element cladding temperature.

In early 2013, the licensee determined that a plant modification would be necessary to prevent the runout of the installed high pressure safety injection (HPSI) pumps during accident scenarios. This modification, which was installed in June 2013, included installation of flow-restricting orifices in the discharge line of each HPSI pump. As a result of the lower injection flows expected after the modification, the licensee contracted an engineering firm to complete an analysis of the expected increase in fuel temperatures that could be expected in an accident. The vendor completed the analysis on July 26, 2013, which showed that in the most limiting scenario, a small break loss of coolant accident, the reduced HPSI flow rates would cause a 309° F increase in the peak cladding temperature. The licensee adopted the vendor's result in Engineering Analysis 13-023, "Fort Calhoun SBLOCA Analysis with Reduced HPSI Flow (AREVA Calc. 32-9130020-001)" on August 16, 2013, and determined that the peak cladding temperature in the most limiting scenario (small break loss of coolant accident) would be 1846°F, still well below the limit of 2200°F specified in 10 CFR 50.46.

On August 1, 2013, the licensee's staff initiated CR 2013-15442, documenting that the AREVA report demonstrated the need to submit a 30 day report as required by 10 CFR 50.46(a)(ii). An action was assigned in the condition report to complete a reportability evaluation by August 9 2013. A draft 10 CFR 50.46 report was created by the condition report originator and provided to the Regulatory Assurance department on August 12, 2013.

The licensee's Regulatory Assurance department subsequently canceled the reportability determination on August 27, 2013, and documented that the 10 CFR 50.46 reporting requirement did not apply. To justify this action, the Regulatory Assurance staff provided the following quote from Nuclear Energy Institute (NEI) Guide 07-05, "10 CFR 50.46 Reporting Guidelines," July 2008, Section 2.2.11, "Input Information:"

> *"The first category of input information is the basic engineering information that describes a specific plant… A change to input information of this type is not considered a change to the evaluation model. Changes and error corrections in this category are not reportable under 10 CFR 50.46."*

The licensee's position was that this type of change was not controlled by 10 CFR 50.46, and that any required action would be identified through compliance with 10 CFR 50.59, "Changes, Tests, and Experiments." The inspectors noted that NEI 07-05 was not endorsed by the NRC staff, and sought guidance from the staff responsible for reviewing 10 CFR 50.46 ECCS analysis at the Office of Nuclear Reactor Regulation. Headquarters staff confirmed that the position described in NEI 07-05 was not endorsed by the NRC and contradicts the requirement of 10 CFR 50.46(a)(3)(ii) which states, in part, that:

> *"For each change to…an acceptable model <u>or in the application</u> of such a model that affects the temperature calculation, …the holder of an operating license…shall report the nature of the change or error…"*

Additionally, the inspectors noted that the NRC has endorsed NEI 96-07, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests and Experiments," Revision 1. NEI 96-07 specifically identifies that changes in anticipated fuel cladding temperature are controlled by 10 CFR 50.46 and would not be subject to the process defined by 10 CFR 50.59.

The inspectors noted that the licensee's procedure for completing reportability determinations contributed to this error. Procedure SO-R-1, "Reportability Determinations," Attachment 8, paragraph 3.4.2 directs the licensee's staff to follow the format provided in NEI 07-05 for preparation of 30 day written reports. While the report format in NEI 07-05 is generally consistent with 10 CFR 50.46, NEI 07-05 contains reportability guidance that is contrary to NRC regulations. This position was communicated to the licensee by the NRC staff on September 12, 2013, and the licensee was informed that the required report had not been submitted within 30 days as required by 10 CFR 50.46(a)(ii).

The licensee submitted the required 10 CFR 50.46 report September 20, 2013 (ML13266A108). This report was subsequently reviewed by the NRC staff date October 2, 2013, and determined to be acceptable. The NRC staff determined that while the configuration change to the HPSI system resulted in a significantly higher peak cladding temperature, it is within the regulatory requirements of 10 CFR 50.46(b)(1).

The licensee initiated CR-2014-00674 on January 16 2014 to document the late report submittal. The licensee initiated CR 2014-01356 on January 29, 2014 to document the fact that Procedure SO-R-1 refers to NEI guidance, which is not endorsed by the NRC.

Analysis. The failure to submit a written report within 30 days of discovery of a significant change to the ECCS peak cladding temperature analysis is contrary to the requirements of 10 CFR 50.46(a)(ii) and is a performance deficiency. This performance deficiency was determined to be subject to traditional enforcement because it impeded the regulatory process, in that the failure to submit a timely report of significant ECCS analytical changes prevented the NRC technical staff from independently evaluating the potential safety implications of reductions in safety injection flow into the reactor during an accident. This violation was determined to be a Severity Level IV violation, because it is consistent with the examples in Paragraph 6.9.d of the NRC Enforcement Policy. Because this violation is subject to traditional enforcement, no cross-cutting aspects have been assigned.

Enforcement. 10 CFR 50.46, “Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors,” states, in part, that any significant change to a limiting ECCS analysis shall be reported to the NRC within 30 days. Contrary to this requirement, the licensee determined that a significant change had been made on August 1, 2013, but failed to submit the required report until September 20, 2013. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee’s corrective action program as CR 2014-00674. (NCV 05000285/2014002-01, “Failure to Make Required 10 CFR 50.46 Report Within Required Time”)

ii. Failure to Translate HPSI Pump Design Requirements to Design Documents

Introduction. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” Specifically, the licensee failed to translate HPSI pump design and runout characteristics to design documents such as the Updated Safety Analysis Report or design calculations.

Description. The emergency core cooling systems (ECCS) at Fort Calhoun Station are designed to provide safety injection flow during various loss of coolant scenarios. One of these systems, the high pressure safety injection (HPSI) system, contains three centrifugal pumps which are capable of injecting water at high pressures into each of the four reactor coolant loops. The inspectors noted that the original pump curves provided by the manufacturer demonstrated expected pump performance to a maximum tested flow of 425 gpm. Pump flows beyond the tested limits are generally considered to be runout conditions, which can lead to rapid degradation of pump internals and overload of pump motors.

The inspectors reviewed pre-operational testing reports from 1972 that demonstrated initial attempts to prevent runout of the HPSI pumps. Additionally, special testing was documented in 1976 that adjusted loop injection flows to avoid runout of the pumps. Despite the constraints of the original design, on April 29, 1977, the licensee removed the limit switch settings from the loop injection valves in an attempt to increase HPSI injection flow based on un-validated information from the vendor that HPSI pump runout for short periods of time was acceptable. The licensee's emergency procedures still contained steps that directed the operators to maintain HPSI total flow below 400 gpm by manually throttling the loop injection valves, so the net effect of this design change was to move the flow limiting design feature from an automatic to a manual action. In a letter dated June 30, 1977, the NRC staff notified OPPD of the safety importance of avoiding runout conditions in HPSI and LPSI systems, and requested that the licensee determine if throttle valves were used in the design to perform this function.

Other operational and design changes were made in the ensuing years that reduced margins to runout conditions. These changes included changes to emergency operating procedures that required HPSI to run at full capacity until certain throttling criteria were met; cross-connecting HPSI trains to pressurize a containment penetration; and ECCS logic changes which extended length of HPSI injection phase prior to Recirculation Actuation Signal (RAS) beyond the limit proposed by the vendor.

On January 30, 2013, while performing analysis in support of a planned modification, the licensee's staff determined that design basis calculations indicated that the HPSI pumps would operate in a run out condition in some design basis accident conditions. The licensee documented this condition in CR 2013-02100, which was screened as Significance Level 2 and assigned a low-tier apparent cause evaluation. The low-tier apparent cause evaluation was completed on March 21, 2013, and documented that the apparent cause was that the station failed to obtain vendor technical information in a 10 CFR 50, Appendix B, validated format. One contributing cause was identified in that design basis documentation for the HPSI system was lacking. The licensee submitted LER 2013-003-0 to the NRC on April 1, 2013, reporting the unanalyzed condition. This LER also described the apparent cause and planned corrective actions.

On May 21, 2013, due to a documented concern of potential NRC escalated enforcement action, CR 2013-02100 was re-categorized as Significance Level 1 and assigned a root cause investigation. The subsequent root cause evaluation was completed on July 4, 2013. The licensee identified that the root cause was a lack of rigorous engineering processes that allowed reductions in margin to runout. The report also identified two contributing causes, in that the pump vendor had supplied inaccurate information to the licensee, and incomplete design basis documentation. One action to prevent recurrence was identified, as well as four new corrective actions.

On July 11, 2013, NRC inspectors met with the licensee to discuss inspector concerns with the root cause analysis. The inspectors shared a concern that over-reliance on technical information from the pump vendor without adequate technical review had prevented the licensee from recognizing this design control issue. The licensee documented the inspectors' concerns in CR 2013-14177. Following this meeting, the licensee's staff revised the root cause analysis on August 27, 2013. This revised report identified a different root cause, in that HPSI pump impeller design and runout characteristics identified during pre-operational testing were not translated into FCS design and licensing basis documents. Several contributing causes were also identified, including: limited staff understanding of HPSI pump design; informal engineering evaluation of vendor-supplied information; failure to internally communicate significance of identified concerns; and failure of the corrective action program to react to adverse trend in vendor calculation inaccuracies. This report also identified two actions to prevent recurrence and 19 corrective actions.

On August 28, 2013, NRC inspectors met again with the licensee's staff to discuss details from the July 4, 2013 version of the root cause analysis and LER 2013-003-0. The licensee again revised the root cause analysis on September 12, 2013, adding another contributing cause in that the licensee had failed to appropriately respond to the NRC's June 1977 letter that specifically warned of the runout concern.

On June 21, 2013, the licensee completed Engineering Change 59874, which permanently installed flow-limiting orifices in the discharge line of each pump, effectively preventing HPSI pump runout conditions from occurring in any plant condition. The inspectors reviewed this design change package, performed field inspections of the completed modifications, and reviewed the results of the completed post-modification testing. The inspectors also noted that the licensee had completed a number of actions and has planned a broad range of programmatic corrective actions to improve maintenance and knowledge of the plant's design and license basis.

On November 27, 2013, the licensee submitted Revision 1 to the LER to update the cause and corrective actions taken for the condition.

Analysis. The inspectors determined that the licensee's failure to translate HPSI pump design and runout characteristics to design documents such as the Updated Safety Analysis Report or design calculations was a performance deficiency. This finding was more than minor because it adversely impacted the design control attribute of the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors reviewed IMC 0609 Attachment 4, “Initial Characterization of Findings”, Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power. As such, the inspectors determined the finding should be evaluated using the SDP in accordance with IMC 0609, “The Significance Determination Process (SDP) for Findings at-Power,” Appendix A, Exhibit 2, “Mitigating Systems Screening Questions.” The finding required a detailed risk evaluation because the high pressure safety injection system was inoperable for some of the large break loss of coolant accident scenarios (at reactor pressures less than 100 psi). Therefore, a Region IV senior reactor analyst performed a detailed risk evaluation.

The analyst used the Fort Calhoun Standardized Plant Analysis Risk (SPAR) model, Revision 8.20 with a truncation limit of E-11 to evaluate this performance deficiency.

Two Pumps Running Scenario: The licensee’s vendor calculated the expected pump runout conditions. The vendor determined that runout conditions would occur at a pump flow of 467 gallons per minute. At this flow rate, the pump discharge pressure would be 244 psia. This particular scenario assumed two high pressure safety injection pumps were running into two headers. The corresponding reactor vessel pressure would be about 100 psia. It’s important to note that the low pressure safety injection system can support early injection and recirculation at this reactor pressure. Experts from the NRC’s Office of Nuclear Reactor Regulation reviewed the calculation and found no significant errors.

For an initial risk estimate, the analyst set the “failure to run” basic events for the high pressure safety injection pumps to a failure of 1.0. This included the train A and B pumps as well as the swing Pump C. However, the analyst noted that the model was not properly failing the pumps in some instances. Each time a high pressure safety injection pump was included in the cutsets, the pump should have failed with a probability of 1.0. In some instances the model failed the pump for other reasons with a nominal failure probability (such as 3.8E-3 for being in test and maintenance). To account for these errors, the analyst set the remaining high pressure safety injection pump basic events (“failure to start,” and “test and maintenance”) to a failure probability of 1.0.

Next the analyst determined that only the loss of coolant accident sequences were affected by the performance deficiency. The analyst considered the following definitions from the SPAR model documentation:

> **Small Loss of Coolant Accident -** The small loss of coolant accident initiating event is defined as a steam or liquid break in the reactor coolant system other than a steam generator tube rupture which exceeds normal charging flow. In this break size range, normally defined as between 3/8 in. and 2 in., normal charging cannot maintain pressurizer level.
>
> **Medium Loss of Coolant Accident -** The medium break loss of a coolant accident initiating event is defined as a steam or liquid break that is large enough

to remove decay heat without using the steam generators but small enough that RCS pressure is above the accumulator and low pressure injection system shutoff pressure.

Large Loss of Coolant Accident - The large loss of coolant accident initiating event is defined as a steam or liquid break that is large enough to rapidly depressurize the reactor coolant system pressure to a point below the low pressure injection and safety injection tank shutoff pressure. This break size is generally defined as being greater than 5 in.

Interfacing System Loss of Coolant Accidents - Interfacing system loss-of-coolant accidents are a class of accidents that can result in the over-pressurization and rupture of systems that interface with the reactor coolant system outside containment. These accidents have been a concern with regard to public health risk due to the potential for fission product release directly to the environment, bypassing the containment structure.

The analyst determined that only the large break and interfacing system loss of coolant accidents should be quantified for this first scenario. In short, small and medium break loss of coolant accidents would result in reactor pressure remaining above the low pressure safety injection (195 psig) and safety injection tank (240 psig) shutoff head conditions, especially considering that a high pressure safety injection pump would be initially running. While it was possible to depressurize below 195 psig as part of a normal shutdown, the residual heat removal system would be employed for this purpose. This would aid operators in that they would have control over decay heat removal and plant pressure. With the residual heat removal system in operation, the high pressure safety injection system was not as risk important.

Thus far, with the previously noted assumptions, the Delta-CDF was 2.8E-6/year.

The analyst noted that the SPAR model loss of coolant accident event tree did not credit the low pressure safety injection system for early recirculation. If the high pressure safety injection pumps failed during early recirculation, the event tree transitioned directly to core damage. This was inconsistent with Emergency Operating Procedure 20, “Functional Recovery Procedure,” Revision 25, in that the procedure directed operators to inject with the low pressure safety injection system for certain conditions (which include low pressure recirculation).

The low pressure safety injection pumps were capable of supporting recirculation provided the reactor pressure was sufficiently low to allow pump operation. The low pressure safety injection pumps provided a nominal discharge pressure of 175 psi. The shutoff head for the pumps was approximately 194 psi. Since, however, the reactor pressure of concern was 100 psi or less, the low pressure safety injection pumps were capable of providing the recirculation function.

Given a high pressure safety injection system failure, the analyst determined that credit for low pressure safety injection recirculation should be provided. To provide credit, the analyst solved the low pressure recirculation fault tree to determine the overall system failure probability (1.3E-3). Since the pumps automatically tripped on a recirculation actuation signal, operators would need to manually start and align the pumps for injection. The nominal human error probability from NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method," was 1.1E-2. The analyst added these two values together for a total failure probability of 1.2E-2.

With this credit, the resultant Delta-CDF was:

Delta-CDF = 2.8E-6 * 1.2E-2 = 4E-8/year

This result was conservative because the analyst provided no credit for operator recognition of runout conditions or mitigating actions to preclude pump damage. Operators received training on runout conditions but it was unclear if adequate indications were available in the control room.

One Pump Operating Scenario: The analyst considered a second scenario where only one of the high pressure safety injection pumps was available for injection – the other two pumps were unavailable because of random failures or for maintenance. For this scenario, the analyst could not conclude that reactor pressure would be sufficiently low to allow the low pressure safety injection system to inject. Therefore, no credit was provided for this function.

The SPAR model specified that the failure probability for a single high pressure safety injection pump (including unavailability for maintenance) was 5.1E-3. Since there are two normally aligned pumps, either pump could be unavailable. The probability that either the A or B pump was unavailable was approximately 1.2E-2. In addition, if one pump failed or was unavailable, operators could place the swing high pressure safety injection pump into service. The analyst considered that operators could fail to properly perform this action. The nominal human error probability for an operator manual action was 1.1E-2. As with the A and B pumps, the pump could fail once placed into service, or otherwise be unavailable because of maintenance. The total unavailability for the C pump was 1.2E-2 + 1.1E-2 = 2.3E-2. Therefore, the total probability that only one pump would be available for injection was 1.2E-2 * 2.3E-2 = 2.8E-4.

The analyst used the SPAR model and set the high pressure safety injection pump common cause failure to run probability to 2.8E-4. This meant that if two pumps were unavailable, the third pump would fail. The nominal common cause failure to run probability was E-7.

This particular scenario was identified during plant simulator demonstrations. Specifically, for a 3 inch pipe break, and one pump running, the inspectors identified that it was possible for the high pressure safety injection pump to fail without first lowering reactor pressure to less than the low pressure safety injection pump discharge head. This correlated to the medium break loss of coolant accident in the

NRC's SPAR model. Therefore, the analyst solved the medium break loss of coolant accident and the intersystem loss of coolant accident sequences.

The analyst noted that this assumption was generally inconsistent with the SPAR model bases document, in that the medium break loss of coolant accident pressure could drop below the accumulator shutoff pressure (about 275 psig). Plant pressure would need to drop below this pressure to establish the runout conditions where pump damage could occur.

The Delta-CDF was 4.2E-8/year.

Total Delta-CDF: The total Delta-CDF was:

Delta-CDF = 4E-8 + 4.2E-8 = 8.2E-8/year

The analyst determined that the finding was of very low safety significance (Green). The dominant core damage sequences included large break loss of coolant accidents where the high and low pressure safety injection systems both failed during early low pressure recirculation. The low pressure safety injection system helped to minimize the risk.

Since the change to the core damage frequency was less than E-7, the analyst was not required to evaluate 1) external events, or 2) the effect on the large early release frequency.

The inspectors determined there was no cross-cutting aspect associated with this finding because events related to identification of needed procedures and specifications occurred in the 1970's and are not indicative of current performance.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control" states, in part, that measures shall be established "to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions." Contrary to this requirement, from April 29, 1977 to June 21, 2013, the licensee failed to translate HPSI pump design and runout characteristics to design documents. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as CR 2013-02100. (NCV 05000285/2014002-02, "Failure to Translate HPSI Pump Design Requirements to Design Documents")

.3 (Closed) LER 05000285/2013-007-01: Containment Air Cooling Units (VA-16A/B) Seismic Criteria

CR 2013-02260 identified that a summary structural analysis (FC03901) indicated that VA-15A/B (Containment Air Cooler/Filter) plenum was overstressed by 100 percent and that VA-16A/B (Containment Air Cooler) plenum would have been overstressed during a design basis seismic event. At the time of discovery, FC03901 indicated that VA-15A/B required cross-bracing, which was added resulting in the equipment being operable. Since VA-16A/B was overstressed, they were considered inoperable.

The licensee causal analysis determined that the design basis information was incomplete at the beginning of commercial operation. A weakness in licensing basis knowledge and a failure to internalize the importance of the design basis, resulted in the organization missing repeated opportunities to correct the initial deficiencies and additional errors were created over time. Also, the early culture established standards and expectations for the organization that resulted in behaviors demonstrating that the operation of the facility was more important than maintaining the license and design basis of the Station. This resulted in long-standing, reinforced, and institutionalized behaviors that resisted external and internal efforts to change.

The NRC identified the overstressed containment air cooler issue, and documented non-cited violation NCV 05000285/2013012-04, "Failure to adequately design containment air coolers structural bracing" in Inspection Report 0500285/2013-012 (ML 13144A772). After the inspection report was issued, the licensee performed additional analysis that concluded the containment coolers were inoperable, but would have been able to perform their safety function. In addition, containment air coolers VA-16A and VA-16B were modified to add structural bracing prior to plant restart.

This Licensee Event Report is Closed.

.4 <u>(Closed) Licensee Event Report 05000285/2013-010-01:</u> HPSI Pump Flow Imbalance

a. <u>Inspection Scope</u>

On May 3, 2013, it was identified that the high pressure injection pump injection flows to the reactor coolant system were not balanced in accordance with the Fort Calhoun Station (FCS) Updated Safety Analysis Report Section 14.15.5.2.

The licensee submitted LER 2013-010-0 on July 2, 2013 to report a condition that could have prevented the fulfillment of a safety function, and as a condition that caused multiple trains of a safety system to become inoperable. The initial revision of this LER contained very little detail and stated that a supplemental report would be made following completion of a causal analysis. The licensee completed an apparent cause evaluation in CR-2013-09949 on October 2, 2013, and subsequently issued Revision 1 of this LER on October 23, 2013.

The licensee determined that the cause of the event was failure to translate the plant physical design into design documents, which allowed plant engineers to modify important plant design aspects without understanding the potential safety impact. The licensee implemented a design change to restore balanced flows in the HPSI injection lines and updated design documents to reflect the importance of maintaining balanced injection flows.

This Licensee Event Report is closed.

b. Findings

i. Failure to Maintain Design Control of HPSI Injection Valves

Introduction. The inspectors identified two examples of a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” The first example involved the licensee’s failure to establish procedures or technical specifications to accomplish required HPSI injection flow balancing. The second example involved the failure to provide controls or testing to ensure that replacement parts for HPSI injection valves were suitable for the application and were capable of supporting the safety-related functions of the HPSI system.

Description. The emergency core cooling systems (ECCS) at Fort Calhoun Station are designed to provide safety injection flow during various loss of coolant scenarios. One of these systems, the high pressure safety injection (HPSI) system, contains three centrifugal pumps which are capable of injecting water at high pressures into each of the four reactor coolant loops. Each loop is provided with an injection line from the A and B HPSI train, and as such the HPSI system provides a total of eight injection lines into the reactor coolant system. Each injection line is provided with a motor-operated injection valve to allow isolation or throttling of flow.

The original safety evaluation report for Fort Calhoun Station did not specifically describe the balancing of HPSI loop injection flow rates. Injection line flow balancing was, however, part of original plant design, and was accomplished by the use of limit switches on each injection valve that stopped the valve travel at a pre-defined position. The inspectors reviewed pre-operational testing reports from 1972 that established these balanced flows. Additionally, special testing was documented in 1976 that adjusted loop injection flows to maintain this balance.

Despite the constraints of the original design, in April 1977 the licensee removed the limit switch settings from the loop injection valves in an attempt to increase HPSI injection flow. This had the unrecognized and undesirable effect of defeating the original design intent of maintaining balanced loop injection flows. The licensee’s emergency procedures still contained steps that directed the operators to maintain balanced injection flows, so the net effect of this design change was to move the flow balancing design feature from an automatic to a manual action.

In a letter dated June 30, 1977, the NRC staff notified OPPD of the safety importance of maintaining balanced loop injection flow rates from the HPSI and LPSI systems, and requested that the licensee determine if throttle valves were used in the design to achieve the required flow balance. The letter further requested that if throttle valves were used, the licensee should propose changes to technical specifications to add a specific set of surveillance requirements that were included as an attachment to the NRC letter.

The licensee provided a brief response to this letter on August 22, 1977, which stated that throttle valves were not used to obtain the needed flow distribution from the HPSI or LPSI systems. The licensee failed to inform the NRC that they had originally been designed with throttled loop injection valves, but had removed this important design feature just prior to receiving the letter from the NRC. As a result, the surveillance requirements described in the June 30, 1977 letter were not added to the Fort Calhoun Station Technical Specifications. The NRC staff reviewed this correspondence against the requirements of 10 CFR 50.9, "Completeness and Accuracy of Information," and determined that due to the age of the issue no enforcement action was appropriate (this regulation did not exist at the time of the inaccurate communication). The inspectors noted that the licensee has documented this inaccurate communication in CR 2013-09949.

Paragraph 14.15.5.2 of the Updated Final Safety Analysis Report (UFSAR) describes that the analysis of record for the small-break loss of coolant accident scenario assumes that the HPSI system flow was modeled to be evenly distributed to the four reactor coolant system cold legs. UFSAR Paragraph 6.2.1 states that the HPSI pump minimum flow rate is designed to provide sufficient injection capacity assuming 25% spillage in the event that one of the four loop injection lines fails.

On April 14, 2013, the license performed a test on HPSI system to benchmark a hydraulic flow model and determine if runout conditions were possible under Work Order 480114. CR 2013-08300 was initiated on April 15, 2013, and included the raw data from the testing, which also demonstrated that the injection flow was not adequately balanced between the reactor coolant loops as described in the UFSAR. The licensee's safety analysis expected loop flows to be balanced within 10 gpm of each other. Data collected during the test (see table below) showed differences as high as 60 gpm between the highest and lowest loop injection flows. As a result, the assumption in the safety analysis that HPSI could provide minimum flow with 25% spillage was not satisfied, in that imbalanced injection flows could cause greater than 25% spillage should the line with the highest flow rate fail in an accident.

Valve Number	RCS Loop	Measured Flow (gpm)
HCV-311	1B	80
HCV-314	1A	75
HCV-317	2A	135
HCV-320	2B	110

CR 2013-09949 was written on May 3, 2013, documenting a concern with the observed flow imbalance. On June 17, 2013, the licensee calculated the flow coefficients (Cv) for the eight HPSI injection valves as follows:

Valve Number	RCS Loop	Measured Cv
HCV-311	1B, Train B	13
HCV-312	1B, Train A	18*
HCV-314	1A, Train B	10
HCV-315	1A, Train A	18*
HCV-317	2A, Train B	22*
HCV-318	2A, Train A	11
HCV-320	2B, Train B	13
HCV-321	2B, Train A	13

* identifies those valves which did not meet design Cv < 13

The licensee discovered that two of the injection valves (HCV-312 and HCV-315) had been replaced in May 2005 and November 2003, (respectively) with valves from a different vendor (Flowserve) than the original valves. The licensee specification sheets for the replacement valves called for a maximum Cv of 13 to match the existing design. Documents produced by the licensee demonstrated that quality control issues with the supplied valves required the valves to be returned to the vendor for disc and seat repairs prior to installation. The post-work testing performed after these valve replacements included stroke-time testing and motor testing. No post-maintenance testing was performed to ensure that the as-received valves met the flow characteristic design requirement to ensure UFSAR assumptions regarding balanced loop injection flows was sustained. Additionally, the licensee discovered that the disc for HCV-317 had been replaced in November 1993, with a part that had been provided meeting the original specification. As with the other valves discussed, no post-maintenance testing was performed to ensure that the rebuilt valve met the flow characteristic design requirement.

Licensee Event Report (LER) 2013-010-0 was submitted to the NRC on July 2, 2013 to report that the imbalanced flow issue could have prevented the HPSI system from performing its safety function. This LER, however, lacked any meaningful details as the licensee had yet to complete a causal evaluation for the loss of safety function. The licensee’s apparent cause evaluation was completed on July 20, 2013 as a “Tier 2” apparent cause report. The initial version of the evaluation identified that the apparent cause of the flow imbalance problem was inadequate post-maintenance testing following engineering changes and maintenance to the HPSI loop injection valves. Related causal factors included failure to identify a surveillance test for flow balancing, lack of engineering understanding of the HPSI design and licensing basis, and lack of supervisory technical oversight. Proposed corrective actions included development of a periodic flow balancing test, revision to post-maintenance testing instructions, improved technical training and documentation, and an audit of the vendor who supplied the incorrect valves.

The licensee has since implemented Engineering Change 59874 which includes a number of design modifications for the HPSI system. One of the included modifications was re-throttling of the HPSI loop injection valves. This change was completed on August 20, 2013, restoring the original plant design and correcting the configuration control errors introduced on three of the eight injection valves. Post-work testing for the completed modification included flow balance testing for the HPSI loop injection lines. The inspectors reviewed the results of this testing and determined that the UFSAR assumptions regarding balanced loop flows are now reflected by HPSI system performance data.

NRC inspectors began onsite inspection activities related to HPSI system issues on August 26, 2013. Based upon questions asked by NRC inspectors regarding the actions proposed for CR 2013-09949, the licensee initiated CR 2013-17630 on September 13, 2013, entitled "Potentially inadequate cause evaluation for an LER." The text of this CR included the following: "…Given the current regulatory interest in this issue it appears that the cause analysis for this issue should receive a more rigorous cause analysis and station management approval."

The licensee subsequently re-performed the apparent cause evaluation for CR 2013-09949, and documented the results on October 2, 2013. While the underlying CR was not upgraded to a higher status, the scope of the revised apparent cause report scope included "Updated the analysis to satisfy ACA Tier 1 requirements due to potential upgrade to ACA Tier 1 per CR 2013-17630." The updated causal analysis included use of multiple analytical tools and identified two underlying root causes that were not described in the initial apparent cause report. The revised report also identified that the apparent cause was more fundamental in nature, in that the original design of the HPSI loop injection valves was not translated into design documents, which affected the quality of many processes including post-maintenance testing. The revised report also identified a contributing cause related to the licensee failing to appropriately respond to the NRC's June 30, 1977 letter that provided specific direction to licensees to carefully control the configuration of throttle ECCS injection valves.

<u>Analysis</u>. The inspectors determined that the licensee's failure to establish procedures or specifications to accomplish required HPSI flow balancing or to provide appropriate controls or testing for replacement parts was a performance deficiency. This finding was more than minor because it adversely impacted the design control attribute of the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors reviewed IMC 0609 Attachment 4, "Initial Characterization of Findings", Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power. As such, the inspectors determined the finding should be evaluated using the SDP in accordance with IMC 0609, "The Significance Determination Process (SDP) for Findings at-Power," Appendix A, Exhibit 2, "Mitigating Systems Screening Questions." The inspectors answered "yes" to the question of "Does the finding represent a loss of system operability and/or function?" The inspectors therefore determined that the finding would require a detailed risk evaluation per IMC 0609 Paragraph 6.0, because the operability of the high pressure safety injection system (both trains) was in question. Therefore, a Region IV senior reactor analyst performed a bounding detailed risk evaluation.

The analyst noted that the NRC's "Standardized Plant Analysis Risk" model included system functional success criteria. The high pressure safety injection system functional success criteria specified: delivery of water to the reactor vessel using one high pressure safety injection pump and at least two out of four intact cold legs. The flow imbalance specified in the functional success criteria was much worse than the actual flow imbalance identified by the finding. Probabilistic risk assessments focus on severe core damage whereas design basis requirements are focused on the potential to exceed emergency core cooling system success criteria and 10 CFR Part 100 limits, which are much more conservative. Since the high pressure safety injection system was capable of meeting the functional success criteria, there was no quantifiable change to the core damage frequency. The finding was not a significant contributor to the large early release frequency.

The analyst determined that the finding was of very low safety significance (Green). The dominant core damage sequences included loss of coolant accidents. However, the high pressure safety injection system remained functional for its probabilistic risk assessment function, which minimized the risk.

The inspectors determined there was no cross-cutting aspect associated with this finding because events related to identification of needed procedures and specifications occurred in the 1970's and are not indicative of current performance. Additionally, the errant replacement of parts of three HPSI injection valves occurred between 1993 and 2006, and are also not indicative of current performance.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control" states, in part, that measures shall be established "to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions" and that measures be established "for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems, and components."

Contrary to this requirement, from June 30, 1977 to present, the licensee failed to establish procedures or Technical Specifications to accomplish required HPSI injection flow balancing. Additionally, since October 1993, the licensee has failed to provide controls or testing to ensure that replacement parts for HPSI injection valves were suitable for the application and were capable of supporting the safety-related functions of the HPSI system. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as CR 2014-02305 (NCV-05000285/2014002-03, "Failure to Maintain Design Control of HPSI Injection Valves").

ii. Failure to Request a License Amendment for Required Change to Technical Specifications

Introduction. The inspectors identified a Severity Level IV non-cited violation of 10 CFR 50.59, "Changes, Tests, and Experiments," and an associated Green finding, for the licensee's failure to request a license amendment for a facility change that required a change to the Technical Specifications. This issue is also associated with a Green finding related to the licensee's failure to follow Procedure NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," and Procedure FCSG-23, "10 CFR 50.59 Resource Manual," both of which require submittal of a license amendment request prior to making a facility change that requires a change to Technical Specifications.

Description. The emergency core cooling systems (ECCS) at Fort Calhoun Station are designed to provide safety injection flow during various loss of coolant scenarios. One of these systems, the high pressure safety injection (HPSI) system, contains three centrifugal pumps which are capable of injecting water at high pressures into each of the four reactor coolant loops. Each loop is provided with an injection line from the A and B HPSI train, and as such the HPSI system provides a total of eight injection lines into the reactor coolant system. Each injection line is provided with a motor-operated injection valve to allow isolation or throttling of flow in the injection line.

The original safety evaluation report for Fort Calhoun Station did not specifically describe the balancing of HPSI loop injection flow rates. Injection line flow balancing was, however, part of original plant design, and was accomplished by the use of limit switches on each injection valve that stopped the valve travel at a pre-defined position. The inspectors noted that pre-operational testing reports from 1972 established these balanced flows. Additionally, special testing was documented in 1976 that adjusted loop injection flows to maintain this balance.

Despite the constraints of the original design, in April 1977 the licensee removed the limit switch settings from the loop injection valves in an attempt to increase HPSI injection flow. This had the unrecognized and undesirable effect of defeating the original design intent of maintaining balanced loop injection flows. The licensee's emergency procedures still contained steps that directed the operators to maintain balanced injection flows, so the net effect of this design change was to move the flow balancing design feature from an automatic design feature to a manual operator action.

In a letter dated June 30, 1977, the NRC staff notified OPPD of the safety importance of maintaining balanced loop injection flow rates from the HPSI and LPSI systems, and requested that the licensee determine if throttle valves were used in the design to achieve the required flow balance. The letter further requested that if throttle valves were used, the licensee should propose changes to the Technical Specifications to add a specific set of surveillance requirements that were included as an attachment to the NRC letter.

The licensee provided a brief response to this letter on August 22, 1977, which stated that throttle valves were not used to obtain the needed flow distribution from the HPSI or LPSI systems. The licensee failed to inform the NRC that they had originally been designed with throttled loop injection valves, but had removed this important design feature just prior to receiving the letter from the NRC. As a result, the surveillance requirements described in the June 30, 1977 letter were not added to the Fort Calhoun Station Technical Specifications.

Paragraph 14.15.5.2 of the Updated Final Safety Analysis Report (UFSAR) currently describes that the analysis of record for the small-break loss of coolant accident scenario assumes that the HPSI system flow was modeled to be evenly distributed to the four reactor coolant system cold legs. Additionally, UFSAR Paragraph 6.2.1 states that the HPSI pump minimum flow rate is designed to provide sufficient injection capacity assuming 25% spillage in the event that one of the four loop injection lines fails.

On April 14, 2013, the licensee performed a test on HPSI system to benchmark a hydraulic flow model and determine if runout conditions were possible under Work Order 480114. The data collected during this test demonstrated that the injection flow was not adequately balanced between the reactor coolant loops as described in the UFSAR. As a result, the assumption in the safety analysis that HPSI could provide minimum flow with 25% spillage was not satisfied, in that imbalanced injection flows could cause greater than 25% spillage should the line with the highest flow rate fail in an accident. CR 2013-09949 was written on May 3, 2013, to evaluate the flow imbalance problem. The initial version of the evaluation identified that the apparent cause of the flow imbalance problem was inadequate post-maintenance testing following engineering changes and maintenance to the HPSI loop injection valves. The licensee also documented a conclusion that “the request from the NRC to initiate a Technical Specification Surveillance to periodically verify balanced flow was not responded to properly.”

On June 17, 2013, the licensee determined the flow characteristics through each HPSI injection line. During this testing, three of the eight injection valves failed to meet the flow characteristics expected by the licensee. The licensee subsequently discovered that injection valves in these three lines had been modified without controlling their configuration to ensure the flow balancing characteristics of the design were sustained.

The licensee has since implemented Engineering Change (EC) 59874 which includes a number of design modifications for the HPSI system. One of the included modifications was re-throttling of the HPSI loop injection valves. This change restored the original plant design, and corrected the configuration control errors introduced on three of the eight injection valves. Post-work testing for the completed modification included flow balance testing for the HPSI loop injection lines. The inspectors reviewed the results of this testing and determined that the UFSAR assumptions regarding balanced loop flows are now reflected by plant performance.

While the design of the facility now supports the safety analysis, the plant Technical Specifications no longer meet the criteria of 10 CFR 50.36. Specifically, 10 CFR 50.36(c)(3) requires that Technical Specifications include sufficient surveillance requirements "to assure that....facility operation will be within safety limits, and that limiting conditions for operation will be met." As specified in the NRC's letter of June 30, 1977, the use of throttle valves to ensure balanced loop injection flow rates requires periodic surveillance testing. Current Technical Specifications at Fort Calhoun Station do not include these surveillance tests. The inspectors determined that the need for a Technical Specification change was recognized by station personnel early in 2013. In a meeting with station management on July 30, 2013, engineering staff who were leading the design change effort documented their plans to submit a license amendment request to add the needed surveillance requirement to the Technical Specifications prior to completion of the modification.

On September 18, 2013, the proposed design change in EC 59874 was presented to the Station Modification and Acceptance Review Team (SMART) for review in preparation for approval by the Plant Review Committee. According to the minutes of the meeting, the licensee's staff initially proposed that the needed flow balancing tests would be performed as surveillance tests in the future as required by 10 CFR 50.36(c)(3). The meeting minutes record that the decision was made by the SMART to perform future flow balancing as a preventative maintenance task rather than as a surveillance test. Discussions with participants in the meeting suggest that station personnel expected that a license amendment request (LAR) would be submitted sometime in the future to formalize the new maintenance procedure as a surveillance test.

The final modification package for EC 59874 included a 10 CFR 50.59 applicability determination form which was completed on October 2, 2013. This applicability determination form required the reviewer to determine if the proposed activity involved a change to the Technical Specifications or operating license. This question was incorrectly answered in the negative. This response was contrary to the licensee's procedure. Procedure NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," Step 4.8.3 states the following; "Any activity requiring prior NRC approval or requiring a change to the Technical Specifications shall not be approved for implementation until NRC approval has been obtained." Additionally, FCSG-23, "10 CFR 50.59 Resource Manual," step 4.2.1.H.1 states the following;

"Per 10 CFR 50.59(c)(1), proposed activities that require a change to the Technical Specifications….must be made via the license amendment process, 10 CFR 50.90."

Contrary to the requirements of NOD-QP-3 and FCSG-23, EC 59874 was implemented on October 9, 2013, without the licensee requesting or receiving a Technical Specification change to add the necessary surveillance requirements for balancing HPSI injection line flow rates.

The inspectors also noted that during the final review process for EC 59874, a plant employee serving as the modification independent reviewer documented the following question: "Why is it acceptable to proceed with this EC without a licensing amendment request?" In response the Regulatory Assurance staff incorrectly stated that it was acceptable to implement the change, and then treat the Technical Specifications as inadequate. In Paragraph 3.5.1 of EC 59874, the licensee clearly stated the intention to use the guidance of NRC Administrative Letter (AL) 98-10 to defer the needed Technical Specification change.

NRC Administrative Letter 98-10, "Dispositioning of Technical Specifications That Are Insufficient to Assure Plant Safety," dated December 29, 1998, was issued "to reiterate to addressees the NRC staff's expectations regarding correction of facility Technical Specifications (TS) when they are found to contain non-conservative values or specific incorrect actions." The inspectors contacted NRC staff responsible for this guidance and validated that AL 98-10 was never intended to allow a facility to avoid a necessary Technical Specification change prior to implementing a plant modification. The licensee's misapplication of this NRC guidance contributed directly to a violation of 10 CFR 50.59(c)(1).

The licensee initiated CR 2014-01029 on January 23 2014, to document this violation and track corrective actions.

<u>Analysis</u>. The failure to follow station procedures which required submittal of a license amendment request prior to implementing the design change that throttled HPSI injection line admission valves was a performance deficiency. This performance deficiency was considered to be of more than minor safety significance because it was associated with the procedure quality attribute of the mitigating systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow station procedures for the 10 CFR 50.59 process caused the Technical Specifications to become insufficient to ensure that the limiting conditions for operation will be met. Using Inspection Manual Chapter 0609 Appendix G, Checklist 4, the inspectors determined that the finding did not result in the loss of any accident mitigation capability and did not require a quantitative risk assessment. This finding was determined to be of very low risk significance (Green).

This performance deficiency was also determined to be subject to traditional enforcement because it impeded the regulatory process, in that the failure to submit a license amendment and add required surveillance testing was in violation of 10 CFR 50.59(c)(1)(i) and caused the Technical Specifications to be deficient with respect to balanced HPSI injection flows assumed in the facility safety analysis.

This violation is associated with a finding that has been evaluated by the SDP and communicated with an SDP color reflective of the safety impact of the deficient licensee performance. The SDP, however, does not specifically consider the regulatory process impact. Thus, although related to a common regulatory concern, it is necessary to address the violation and finding using different processes to correctly reflect both the regulatory importance of the violation and the safety significance of the associated finding. This violation was determined to be a Severity Level IV violation, because it is consistent with the examples in Paragraph 6.1.d of the NRC Enforcement Policy.

The finding had a cross-cutting aspect in the training aspect of the human performance cross-cutting area because the licensee's staff failed to understand and misapplied NRC generic guidance related to discovery of insufficient technical specifications (H.9).

Enforcement. 10 CFR 50.59, "Changes, Tests, and Experiments" states in section (c)(1), in part, that "a licensee may make changes in the facility as described in the final safety analysis report (as updated)…without obtaining a license amendment pursuant to paragraph 50.90 only if: (i) A change to the technical specifications incorporated in the license is not required…" Contrary to this requirement, on October 9, 2013, the licensee made a change to the facility as described in the final safety analysis report without obtaining a license amendment pursuant to paragraph 50.90 when a change to the technical specifications incorporated in the license was required. Specifically, the licensee completed a design change that throttled the HPSI branch line injection valves and invoked a new required surveillance test without obtaining a license amendment to add the surveillance requirement to technical specifications. Because this finding was of very low safety significance (Green), the associated violation was screened as Severity Level IV, and the violation was entered into the licensee's corrective action program as CR 2014-01029, this violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. (NCV 05000285/2014002-04, "Failure to Request a License Amendment for Required Change to Technical Specifications").

iii. Untimely Submittal of Required Licensee Event Reports

Introduction. The inspectors identified two examples of a cited Severity Level IV violation of 10 CFR 50.73, "Immediate Notification Requirements for Operating Nuclear Power Reactors," for the licensee's failure to submit a required licensee event report within 60 days following discovery of an event requiring a report.

Description.

Example 1:

Paragraph 14.15.5.2 of the Updated Final Safety Analysis Report (UFSAR) describes that the analysis of record for the small-break loss of coolant accident scenario assumes that the HPSI system flow was modeled to be evenly distributed to the four reactor coolant system cold legs. UFSAR Paragraph 6.2.1 states that the HPSI pump minimum flow rate is designed to provide sufficient injection capacity assuming 25% spillage in the event that one of the four loop injection lines fails.

On April 14, 2013, the licensee performed a test on HPSI system to benchmark a hydraulic flow model and determine if runout conditions were possible under Work Order 480114. The data collected during this test suggested a possible vibration concern with the 2B HPSI pump. CR 2013-08300 was initiated on April 15, 2013 to document the vibration concern. Included with the CR was the raw data from the troubleshooting, which also demonstrated that the injection flow was not adequately balanced between the reactor coolant loops as described in the UFSAR. The licensee sent this data to an off-site vendor for review and analysis.

On May 3, 2013, the licensee's staff initiated CR 2013-09949 to document the results of the evaluation of the April 14 test data. This CR documented the conclusion that the HPSI injection flows measured on April 14, 2013, were imbalanced, and that as a result, the assumption in the safety analysis that HPSI could provide minimum flow with 25% spillage was not satisfied.

An action was assigned from CR 2013-09949 to complete a reportability evaluation for the condition. This reportability evaluation was assigned on May 17, 2013, and given a due date of May 24, 2013. The due date for this action was subsequently extended five times by the licensee's staff prior to completion of the reportability evaluation on June 14, 2013, sixty-one days after the data was observed on April 14, 2013. Throughout this process, the "event date" listed was the date that CR 2013-09949 documented the results of the evaluation of the data, rather than the date the data was observed by the licensee's staff. Additionally, the inspectors noted that contrary to Procedure SO-R-1, "Reportability Determinations," the reportability evaluation was not reviewed by the Plant Review Committee. After being informed of this process error, the licensee initiated CR 2014-00958. The inspectors determined that this process error was of minor safety significance and did not represent a finding.

The license submitted LER 2013-010-0 on July 2, 2013, sixty days after the initiation of the CR on May 3, 2013, but seventy-nine days after the flow imbalance was observed by the licensee's staff. The licensee submitted an LER supplement on October 23, 2013, as LER 2013-010-1.

The inspectors reviewed the LER to determine if it had been submitted with the time required by 10 CFR50.73. Section 50.73(a)(1), requires, in part, that the licensee submit a LER for any event of the type described in this paragraph within 60 days after the discovery of the event. The inspectors noted that the licensee's internal procedure SO-R-1, "Reportability Determinations," Revision 31 states in

Paragraph 4.1.1 that “Reportabilities shall be made based on the discovery date for the event rather than the date when an evaluation of the event is completed in accordance with NUREG 1022.”

The inspectors reviewed the guidance of NUREG 1022, “Event Report Guidelines: 10 CFR 50.72 and 50.73,” Revision 3, and determined that the language in the licensee’s procedure is generally consistent with that of NUREG 1022, Section 2.5, Time Limits for Reporting. The inspectors noted that the NUREG 1022 guidance also recognizes that some conditions require evaluation to determine if a reportable condition exists. In these cases, the NUREG guidance explains that the evaluation should proceed on a time scale commensurate with the safety significance of the issue, and that when operability of the affected equipment is in doubt, appropriate actions such as reporting should be commenced. The inspectors reviewed the operability determination attached to CR 2013-08300 on April 15, 2013, (which included the flow imbalance data) and noted that the licensee completed the associated operability evaluation on same day the CR was written (April 15, 2013). This operability evaluation documented that the HPSI system was already inoperable due to the unrelated HPSI runout condition. Additionally, the flow imbalance condition represented a loss of safety function for the HPSI system, a condition that would normally require action to place the station in hot shutdown within 12 hours and cold shutdown within 36 hours. The inspectors determined that the eighteen day delay between recording of the flow imbalance data in CR 2013-08300 and the “event date” in the licensee’s reportability evaluation was not appropriate, and was inconsistent with Procedure SO-R-1 and NUREG 1022. Based upon an event date of April 15 2013, the LER should have been submitted no later than June 14, 2013, as required by 10 CFR 50.73(a)(1).

Example 2:

On July 25, 2013, while responding to questions by NRC inspectors regarding runout susceptibility of the containment spray pumps, the licensee discovered that anticipated operating conditions during accident scenarios may exceed analyzed limits for the pumps. The licensee documented this concern in CR 2013-15047. Specifically, design basis calculations and vendor information for the containment spray system did not describe acceptable pump operations at flows greater than 3000 gpm, which would exist in some accident scenarios. Additionally, no analysis had been performed for a potential pump/motor coupling failure, which would require the remaining containment spray pump to provide flow through both containment spray headers.

On July 26, 2013, the licensee documented in the immediate operability determination for CR 2013-15047 that no reportable condition existed “due to reportability evaluations written for CRs 2007-01530, 2007-02241, and 2008-01683.”

CR 2013-19722 was written on October 22, 2013, which documented that new pump curve for containment spray pumps revealed that anticipated motor loads would be significantly above the horsepower rating for the motor. The containment spray pump motors are rated for a nominal 300 BHP, and can be acceptably operated at 115 percent of this nominal motor load (i.e. up to a service factor of 1.15). Prior to this evaluation, the design basis assumed that maximum containment spray pump flow would be 3200 gpm, resulting in a motor load of 344 BHP and a service factor of 1.15. The new pump curve documented in CR 2013-19722 demonstrated that actual motor load at 3200 gpm would be 365 BHP, for an unacceptable service factor of 1.22. The motor vendor determined that under this load, the motors would be expected to fail within approximately 10 minutes.

Based on questions from the NRC resident inspectors, the licensee initiated CR 2013-19930 on October 25, 2013 to document the need to reconsider reportability for the condition identified in CR 2013-15047. A reportability evaluation was subsequently assigned as an Action Item 005 to CR 2013-15047 on October 26, and completed on October 31,2013. This evaluation determined that the issues described required reporting in accordance with 10 CFR 50.73. Licensee Event Report 2013-017-0 was submitted to the NRC on December 27, 2013. This report was submitted 57 days after the completion date of the reportability evaluation, but 62 days after the "event date" of October 26, 2013 on the reportability evaluation. The inspectors also noted that the report was sent 66 days after CR 2013-19722 documented the potential overload condition.

Enforcement Policy Discussion:

The inspectors determined that this violation was repetitive in nature, as described in the NRC Enforcement Policy. Paragraph 2.3.2(a)(3) of the NRC Enforcement Policy provides that one of the criteria that must be met for a violation to be screened as a non-cited violation is that the violation must not be "repetitive", or if repetitive must not have been identified by the NRC. Repetitive, with regard to this aspect of the Enforcement Policy, is defined as follows:

> "A violation is considered 'repetitive' if it could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation. In addition, a violation is considered 'repetitive' if a previous licensee finding occurred within the past 2 years of the inspection at issue, or the period between the last two inspections, whichever is longer."

The inspectors noted that a similar violation had been documented in NRC Inspection Report 2013008 dated July 16, 2013 (ML13197A261). That report included NCV 05000285/2013008-43, entitled "Untimely Submittal of Licensee Event Reports." The NCV documented nine examples of LERs that were submitted later than required by 10 CFR 73(a)(1). The NCV also documented that the late reports were caused by a backlog of significant technical issues as well as a fundamental misunderstanding about what constituted the time of discovery. Corrective actions to address knowledge gaps involving the reportability process were initiated under Condition Report CR 2012-03796, completed in July 2012. The inspection report documented that following completion of these corrective actions, LERs submitted after August 2012 were generally timely and met the 60 day requirement specified in 10 CFR 50.72(a)(1).

The inspectors reviewed the completion status of the licensee's corrective actions for NCV 05000285/2013008-43 as documented in CR 2012-03796. All but one of the assigned corrective actions was completed prior to submittal of untimely LER 2013-010-0 and LER 2013-017-0. The one remaining item was classified as a long term corrective action assigned an original due date of August 31, 2012. The scope of this action was to revise Procedure SO-R-1 to more closely align with the Exelon fleet model. The due date for this remaining action has since been extended nine times and is currently scheduled for completion in February 2014. The most recent due date extension emphasized that the pending changes "are enhancements to the procedure..." and "Shift Managers have demonstrated the ability to perform reportability determinations." The inspectors also noted that Procedure SO-R-1 has been revised seven times since CR 2013-03796 was initiated on May 8, 2012, yet the action in CAP has not been recorded as completed and errant reportability evaluations continue to occur.

Given that most of the licensee's corrective actions for NCV 05000285/2013008-43 were completed prior to the performance of the reportability evaluation for CR 2013-09949 or CR 2013-15047, and that less than two years have transpired since the violation was documented, the inspectors determined that this violation meets the enforcement policy definition of a repetitive violation.

The licensee initiated CR 2014-01358 on January 29, 2014 to document this repetitive violation.

Analysis. The inspectors determined that the failure to submit a required LER was a violation of 10 CFR 50.73. The violation was evaluated using Section 2.2.4 of the NRC Enforcement Policy, because the failure to submit a required LER may impact the ability of the NRC to perform its regulatory oversight function. As a result, this violation was evaluated using traditional enforcement. In accordance with Section 6.9(d)(9) of the NRC Enforcement Policy, this violation was determined to be a Severity Level IV violation. The team determined that a cross-cutting aspect was not applicable to this performance deficiency because the failure to make a required report was strictly associated with a traditional enforcement violation.

Enforcement. Title 10 of the Code of Federal Regulations, Section 50.73(a)(1), requires, in part, that the licensee submit a LER for any event of the type described in this paragraph within 60 days after the discovery of the event. Contrary to the above, between June 14 and July 2, 2013, the licensee failed to submit a LER for an event meeting the requirements for reporting specified in 10 CFR 50.73. This violation is not being treated as a new violation. Instead, it is considered as a related violation to the non-cited violation issued in July 2013, which dealt with nine examples of a failure to submit timely LERs. This violation is being treated as a cited violation, consistent with Section 2.3.2(a)(3) of the NRC Enforcement Policy:

VIO 05000285/2014002-05, "Untimely Submittal of Required Licensee Event Reports." (EA-14-037)

.5 (Closed) Licensee Event Report 05000285/2013-015-00: Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82

"On September 13, 2013, it was identified that the floor coatings in Rooms 81 and 82 may not maintain its integrity during a high energy line break environment allowing water to migrate into the rooms below which contain the diesel generators and safety related switchgear. This was reported on September 23, 2013, under 10 CFR 50.72(b)(3)(ii)(8), Unanalyzed Condition (Event Notification 49378). Fort Calhoun Station was shutdown in MODE 5 when the condition was identified and entered into the station's corrective action program as Condition Report 2013-17605.

"Engineering is reviewing this condition and the evaluation performed in 2009 for a previous condition. The completed results of this review will be used to update this report."

This Licensee Event Report is closed. Revision 1 of this Licensee Event Report was submitted on February 14, 2014.

.6 (Open) Licensee Event Report 05000285/2013-015-01: Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82

"On September 23, 2013, it was identified that the floor structure in Rooms 81 and 82 may not maintain its integrity during a high energy line break environment allowing water to migrate into the rooms below that houses the diesel generators and safety related switchgear. This was reported on September 23, 2013, under 10 CFR 50.72(b)(3)(ii)(B), Unanalyzed Condition (Event Notification 49378). Fort Calhoun Station was shutdown in MODE 5 when the condition was identified and entered into the station's corrective action program as Condition Report 2013-18103.

"A cause evaluation was completed and determined that corrective actions in CR 2009-0687 root cause analysis (RCA) did not resolve water intrusion into Auxiliary Building rooms containing safety related equipment due to lack of technical rigor and flawed decision making.

"The floor in Room 82 was recoated. The seismic gap between containment and the auxiliary building was sealed. All penetrations that had openings below 2 feet above the floor were coated and the area around the impingement plate was sealed. Cracks in the ceilings of the switchgear and upper electrical penetration rooms were repaired."

.7 (Open) Licensee Event Report 05000285/2013-016-00: Reporting of Additional High Energy Line Break Concerns

"On October 18, 2013, as part of an extent of condition for LERs 2012-017 and 2013-011, Fort Calhoun Station (FCS) personnel identified a potential additional high energy line break (HELB) concern with the piping associated with the letdown heat exchanger (LDHX).

Subsequently on November 5, 11, 16, and 20, additional HELB impacts were also identified. These impacts involved increased loads on supports in the piping subsystem MS-4099 (main steam supply to FW-10), high energy line cracking (HELC) related to auxiliary steam in various rooms in the power block, the assumptions made regarding diesel generator operability during a HELB, and the quality of the steam to FW-10, the steam-driven auxiliary feedwater pump.

"It was previously determined and reported that FCS did not fully implement and/or maintain the Electrical Equipment Qualification (EEQ) program to meet the requirements of 10 CFR 50.49. As a consequence, the equipment included in the EEQ program, the systems included in the High Energy Line Break (HELB) Analysis and the environmental conditions used by the EEQ program have not been maintained current or in an auditable manner. In addition to the corrective actions (CA) to resolve the EEQ/HELB program issues previously reported, additional CAs are being pursued to address the individual conditions listed above."

.8 <u>(Closed) Licensee Event Report 05000285/2013-017-00:</u> Containment Spray Pump Design Documents do not Support Operation in Runout

a. <u>Inspection Scope</u>

On July 25, 2013, in response to a question from the NRC, the licensee identified that the containment spray pumps could experience runout conditions in some accident scenarios, and that design basis documents for the system did not support operability. Specifically, in the event that one of the two installed containment spray pumps experienced a pump/motor coupling failure, the remaining pump would have attempt to provide flow to both containment spray headers and would have failed due to motor overload.

The licensee issued the LER 2013-017-0 on December 17, 2013 to report a condition not allowed by Technical Specifications, that could have prevented the fulfillment of a safety function, and as a condition that caused multiple trains of a safety system to become inoperable. As a corrective action, the licensee implemented a temporary modification that throttled a valve at the discharge of each containment spray pump to prevent runout conditions from occurring. The licensee described plans to complete a permanent modification in the future to prevent runout.

The required reduction in containment spray flow rates required further analysis by the licensee to determine if the current Main Steam Line Break (MSLB) analysis in USAR Table 14.16-3 is still bounding. The NRC technical staff reviewed the results of the licensee's evaluation of the impact of the modification on containment peak pressure and temperature, and determined that the licensee's MSLB accident containment analysis was acceptable, and that the reduction in the containment spray system flowrates did not require a license amendment.

In addition to the findings described below, the inspectors determined that this LER was not submitted within the time required by 10 CFR 50.73(a)(1). The enforcement aspects of this issue are discussed in Section 4OA3.4 of this report.

This Licensee Event Report is closed.

b. Findings

i. Failure to Restore Compliance for Containment Spray Runout Conditions

Introduction. The inspectors identified a cited Green violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to take timely corrective action for a condition adverse to quality. Specifically, the inspectors noted that the licensee failed to restore compliance following NRC identification of the licensee's failure to correct runout conditions in the containment spray system documented as NCV 05000285/2008003-05 in August 2008.

Description. The containment spray system at Fort Calhoun Station consists of two safety-related centrifugal pumps which are designed to provide flow through either of two spray headers in containment to lower the peak containment pressure during the first twenty minutes of a main steam line break accident. Open cross-connect valves between the discharge piping on each pump allow each pump to supply flow to both headers. This configuration challenges the operability of the pumps in that a failure of one of the pumps could cause the remaining pump to provide flow through both spray headers and result in runout of the remaining pump and eventual pump failure due to high vibrations or motor overload. This design vulnerability was identified by the licensee as early as 1990, and interlocks were added to prevent both spray header isolation valves from opening unless both containment spray pump motors were running.

During an inspection performed under Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area," on March 17, 2008, NRC inspectors identified an operability concern with the response of the containment spray system. Specifically, the inspectors identified a potential vulnerability in that a mechanical failure of a containment spray pump (such as a pump shaft shear or a stuck discharge check valve) could result in the runout failure of the remaining pump. These two scenarios of concern were documented by the licensee in CR 2008-1666 and CR 2008-1683 respectively. Given the similarity of the pump shaft shear and failed check valve scenarios, the licensee consolidated many of the needed corrective actions and tracked them under CR 2008-1683.

In response to CR 2008-1666 and CR 2008-1683, station operators completed an operability evaluation on March 19, 2008. This operability evaluation contained the following discussion of the scenarios of concern:

> "The two events that credit Containment Spray are a Loss of Coolant Accident (LOCA) and a Main Steam Line break (MSLB)....During a MSLB the containment

heat removal capability of the CS system is provided in addition to the heat removal capability of the containment Coolers….therefore the LOCA response will be the one mainly addressed."

The licensee completed Safety Analysis for Operability (SAO) 2008-02 on March 22, 2008 to define the conditions which must exist to assure operability until final corrective action were taken. These steps included updating plant procedures and the UFSAR to define operator actions to recognize pump shaft shear and check valve failures; adding procedural requirements to ensure all containment fan coolers remained operable until the start of the 2008 refueling outage; and completion of Engineering Change 30663, "GSI 191 Implementation," during the 2008 refueling outage, after which SAO 2008-002 could be closed. The inspectors noted that the purpose of EC 30663 was to provide the engineering justification for retaining the existing containment sump strainer design. A necessary input to this EC was completion of EC 40070, which eliminated the containment spray function for a LOCA.

On May 5, 2008, the licensee completed an apparent cause evaluation for this condition. The cause was determined to be "less than adequate evaluation of the single failure impact of CS system subcomponents on the containment spray system." Several actions were identified to correct the condition, including closure of SAO 2008-02; conducting training for engineering staff on identification of single failures; and training for staff on procedure changes. Several additional actions were identified to prevent recurrence including procedure revisions to clarify plant modification procedural controls and clarify single failure criteria.

On May 28, 2008, the Plant Review Committee approved closure of SAO 2008-002 following completion of EC 30663. In the supporting memorandum to the Plant Review Committee, the licensee's staff wrote that "After implementation of this EC, the CS Pumps are no longer credited for a LOCA event." The inspectors noted, however, that completion of EC 30663 did nothing to resolve the vulnerability of the pump failure in the other design basis event for which containment spray was credited (MSLB). Finally, the inspectors noted that on January 15, 2010, the licensee documented that all actions necessary to address NCV 2008003-05 had been completed, and on January 19, 2010, CR 2008-1683 was closed.

On July 18, 2013, NRC inspectors again inquired about the runout susceptibility of the containment spray pumps. In response to these questions by the inspectors, the licensee discovered that anticipated operating conditions during a MSLB scenario may exceed analyzed limits for the pumps. The licensee documented this concern in CR 2013-15047 on July 25, 2013. Specifically, design basis calculations and vendor information for the containment spray system did not describe acceptable pump operations at flows greater than 3000 gpm, which would exist within the first twenty minutes of a main steam line break scenario. Additionally, no analysis had been performed for a potential pump/motor coupling failure, which would require a single containment spray pump to provide flow through both containment spray headers. After subsequent analysis of the MSLB scenario by the motor vendor, the licensee initiated CR 2013-19722 on October 22, 2013, which described that the "acceptance review of a new pump curve for the containment spray pumps identified the motor horsepower required was beyond the service factor of 1.15." A subsequent reportability evaluation further documented that "Additional evaluations performed by an electric motor vendor to determine if the CS Pump motor can support operation in a runout condition determined that the motor may fail after approximately 10 minutes of operation." On December 27, 2013, the licensee reported this condition in Licensee Event Report 2013-017-0 as a condition which was prohibited by the plant's Technical Specifications and as a condition that could have prevented the fulfillment of the safety function of containment spray system.

Corrective actions taken for CR 2013-15047 included completion of an analysis of containment spray pump operation in an MSLB event; revision of CS design documentation; analysis of motor performance by electrical vendor; and completion of a temporary modification which throttles the CS pump discharge valves to provide additional system resistance and prevent runout. The action to change the system resistance was completed on November 24, 2013, which put the station back into compliance by correcting the condition adverse to quality originally identified by NRC in NCV 2008003-05. Future corrective actions will include a permanent design change to prevent CS pump runout.

Inspectors determined that this violation demonstrated that the licensee had failed to restore compliance within a reasonable period of time after the previous violation was identified, as described in Paragraph 2.3.2(a)(2) of the NRC Enforcement Policy. Specifically, the inspectors noted that NCV 05000285/2008003-05, entitled "Inadequate Corrective Actions for a Containment Spray Design Deficiency," described that the licensee had initiated CR 2008-01683 to document the violation. The inspectors reviewed the disposition of CR 2008-01683, and determined that neither the actions taken to correct the violation, nor the actions taken to prevent recurrence were sufficient to resolve the performance deficiency. At the time that the concern was again raised by NRC inspectors on July 18, 2013, CR 2008-01683 and all of its associated corrective actions were already completed and closed.

During an extent of condition review for a runout concern in the HPSI system, the licensee identified that design basis calculations FC07077 and FC07078 predicted flowrates beyond the manufacturer's pump curve. Action 2013-02100-008 was assigned on April 17, 2013 to "validate and document the CS pumps can operate successfully and meet design requirements in their extended flow region…" The language of the action item presumed a successful outcome, and on May 17, 2013 the action item was closed based upon previous vendor correspondence (i.e. no new analysis was conducted), and the licensee documented that the "CS pumps are acceptable as is. No additional actions are required." This action and the inadequate response represent a recent opportunity to identify and correct this condition prior to NRC's actions in the matter.

The licensee initiated CR 2014-02242 on February 19, 2014 to document this failure to restore compliance.

Analysis. The inspectors determined that the licensee's failure to correct a condition adverse to quality was a performance deficiency. This finding was more than minor because it adversely impacted the SSC and barrier performance attribute of the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (containment) protect the public from radionuclide releases caused by accidents or events.

The inspectors reviewed IMC 0609 Attachment 4, "Initial Characterization of Findings", Table 3 – SDP Appendix Router. While this issue was identified during a refueling outage, the inspectors determined that the majority of the exposure time for this violation occurred with the reactor at power. As such, the inspectors determined the finding should be evaluated using the SDP in accordance with IMC 0609, "The Significance Determination Process (SDP) for Findings at-Power," Appendix A, Exhibit 3, "Barrier Integrity Screening Questions." The inspectors determined that the finding did not represent an actual open pathway in containment or containment isolation logic, nor did the finding represent an actual reduction in the function of containment hydrogen igniters. Based on the guidance in the Exhibit 3 checklist the inspectors determined that the finding was of very low safety significance.

The inspectors determined that finding had a cross-cutting aspect of avoiding complacency in the human performance area, because the licensee's staff failed to recognize latent issues even while expecting successful outcomes (H.12).

Enforcement. Title 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," 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 nonconformances are promptly identified and corrected." Contrary to the above, between August 12, 2008 and November 24, 2013, the licensee failed to take adequate corrective action to assure that a condition adverse to quality was corrected. Specifically, actions were not taken to correct NRC-identified runout concerns in the containment spray system until these concerns were again raised by the NRC on July 18, 2013. This violation is not being treated as a new violation. Instead, it is considered as a continuation of the non-cited violation issued in August 2008, which identified the licensee's failure to take corrective actions for runout concerns in the containment spray system. This violation is being treated as a cited violation, consistent with Section 2.3.2(a)(2) of the NRC Enforcement Policy: VIO 05000285/2014002-06, "Failure to Restore Compliance for Containment Spray Runout Conditions." (EA-14-037)

ii. Inadequate 10 CFR 50.59 Screening for Containment Spray Design Change

Introduction. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" for the licensee's failure to complete a 10 CFR 50.59 screening that met the requirements of NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," Revision 37.

Description. 10 CFR 50.59, "Changes, Tests, and Experiments," contains requirements for the process by which licensees may make changes to their facilities and procedures as described in the safety analysis report, without prior NRC approval, under certain conditions. Through the issuance of Regulatory Guide 1.187, “Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments,” the NRC endorsed industry-developed guidance for compliance with 10 CFR 50.59. This industry guidance, documented in NEI 96-07, “Guidelines for 10 CFR 50.59 Evaluations,” Revision 1, provides methods that are acceptable to the NRC staff for complying with the provisions of the rule.

Section 4.2 of NEI 96-07 describes the process used to screen plant changes to determine if further evaluation is required. This process involves answering a number of screening questions. If any of these questions is answered in the affirmative, the NEI guidance requires that the change be subjected to a “evaluation” to determine if NRC review and approval is required prior to making the change.

The inspectors noted that the licensee’s guidance on implementation of the 10 CFR 50.59 rule is contained within two documents: NOD-QP-3, “10 CFR 50.59 and 10 CFR 72.48 Reviews,” Revision 37, and FCSG-23, “10 CFR 50.59 Resource Manual,” Revision 8. Step 4.4.1.A of NOD-QP-3 requires plant personnel to complete the screening activity using Form FC-154A and the guidance within FCSG-23. Step 4.4.1.C requires the performer to provide written justification for each of five questions to demonstrate that the overall conclusion is that an evaluation is not required.

The inspectors reviewed the completed 10 CFR 50.59 screening that was performed for Engineering Change (EC) 62416 on November 14, 2013. This EC was implemented to change the normal position for the containment spray pump discharge isolation valve from full open to throttled. This new position was required to prevent the runout of the containment spray pumps in certain accident conditions, and involved using the normally-open gate valve to throttle flow rates of up to 3000 gpm during accident conditions. During these operating conditions, the new position of the gate valve would be approximately 80 percent closed, exposing the valve to high differential pressures and creating a number of potentially unanalyzed degradation mechanisms in the downstream piping, including vibration, flow erosion, and debris blockage.

The inspectors noted that the completed FC-154A screening form answered “no” to all five screening questions. The inspectors developed a concern with the licensee’s response to Question 1, which asks the screener to answer the following question:

1. Does the proposed activity involve a change to an SSC that adversely affects a UFSAR described design function?

The inspectors determined that this response was in error, in that the proposed change adversely affected the UFSAR described design function of the containment spray system, due to the possible adverse effects of throttling the gate valves on the system valves and piping. The inspectors determined that in answering "no" to this question, the licensee failed to properly implement Step 4.4.1.C of Procedure NOD-QP-3. After sharing this concern with the licensee, the licensee initiated CR 2013-22007 documenting the procedural error. CR 2013-22007 recorded that the initial FC-154A screen had incorrectly determined that a 10 CFR 50.59 evaluation was not required. The licensee's staff subsequently re-performed the FC-154A screening form on November 29, 2013, and determined that a 10 CFR 50.59 evaluation was required. The NRC staff reviewed the resulting 10 CFR 50.59 screening and evaluation and determined that they had been properly performed, and that a license amendment request was not required prior to implementation of the activity.

The licensee documented this procedural violation in CR 2014-01357 on January 29, 2014.

Analysis. The failure to follow station procedures which required completion of an accurate 10 CFR 50.59 screening of a design change was a performance deficiency. This performance deficiency was considered to be of more than minor safety significance because it was associated with the design control attribute of the mitigating systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to follow station procedures for the 10 CFR 50.59 process prevented the licensee's staff from evaluating the adverse impacts of the change on the facility. Using Inspection Manual Chapter 0609 Appendix G, Checklist 4, the inspectors determined that the finding did not result in the loss of any accident mitigation capability and did not require a quantitative risk assessment. This finding was determined to be of very low risk significance (Green).

The inspectors determined that this finding had a cross-cutting aspect of conservative bias in the human performance area, because the licensee's staff ensure that the proposed design change was safe in order to proceed rather than unsafe to stop (H.14).

Enforcement. Title 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" states, in part, that activities affecting quality shall be prescribed by documented procedures and accomplished in accordance with these procedures. The licensee established Procedure NOD-QP-3, as the implementing procedure for "10 CFR 50.59 Reviews," an acivity affecting quality. Contrary to this requirement, between November 13 and November 29, 2013, the licensee failed to accomplish an activity affecting quality in accordance with the procedure. Specifically, the licensee completed a 10 CFR 50.59 screening that did not meet the requirements of NOD-QP-3, "10 CFR 50.59 and 10 CFR 72.48 Reviews," Revision 37. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as CR 2014-01357. (NCV 05000285/2014002-07, "Inadequate 10 CFR 50.59 Screening for Containment Spray Design Change")

.9 Open) Licensee Event Report 05000285/2013-019-00: Non-Seismic Circulating Water Pipe Could Disable Raw Water Pumps

"On December 2, 2013, NRC inspectors questioned the validity of an operability determination performed by the station on a non-safety grade pipe in the Raw Water pump vaults. The concern was determined to be valid and on December 3, 2013 at 0038 CST, an operability evaluation for Condition Report (CR) 2013-22090 confirmed operability of the RW pumps with interim actions to prevent circulating water flow from the affected 12 inch pipe into the raw water vault during a seismic event. Interim compensatory actions to maintain operability of the raw water pumps are to secure the screen wash system and establish a clearance.

A cause analysis is in progress and an update to this LER will be provided with additional information.

A design change was completed to eliminate the adverse interaction noted above."

These activities constitute completion of five event follow-up samples, as defined in Inspection Procedure 71153.

4OA4 IMC 0350 Inspection Activities (92702)

Inspectors continued implementing IMC 0350 inspection activities, which included follow-up of the restart checklist items contained in the Confirmatory Action Letter (CAL) issued February 26, 2013 (EA-13-020, ML 13057A287). The purpose of these inspection activities was to assess the licensee's performance and progress in addressing its implementation and effectiveness of FCS's Integrated Performance Improvement Plan (IPIP), significant performance issues, weaknesses in programs and processes, and flood restoration activities.

Inspectors used the criteria described in baseline and supplemental inspection procedures, various programmatic NRC inspection procedures, and IMC 0350 to assess the licensee's performance and progress in implementing its performance improvement initiatives. Inspectors performed on-site and in-office activities, which are described in more detail in the following sections of this report. This section documents inspection activities that occurred prior to closure of the CAL on December 17, 2013. Specific documents reviewed during this inspection are listed in the attachment.

The following inspection scope, assessments, observations, and findings are documented by CAL restart checklist item number.

.3 Adequacy of Significant Programs and Processes

Section 3 of the Restart Checklist addresses major programs and processes in place at FCS. Section 3 reviews also include an assessment of how the licensee addressed the NRC Inspection Procedure 95003 key attributes as described in Section 6.

.b Equipment Design Qualifications

This item of the Restart Checklist verifies that plant components are maintained within their licensing and design basis. Additionally, this item provides monitoring of the capability of the selected components and operator actions to perform their functions. As plants age, modifications may alter or disable important design features making the design bases difficult to determine or obsolete. The plant risk assessment model assumes the capability of safety systems and components to perform their intended safety function successfully.

(1) Safety-Related Parts Program

i. Inspection Scope

The team reviewed the licensee's assessment of issues related to the safety-related parts program at FCS. The team assessed the licensee's equipment design quality classifications review for inconsistent quality classifications. Additionally, the team assessed the licensee's review of the use of non-safety-related parts in safety-related applications. Specifically, the team assessed the RCA for CR 2012-05615, for which the problem statement was:

> *"FCS did not maintain compliance in all cases to the Updated Safety Analysis Report, Appendix A, Section 4.0, Design Control, such that non-safety graded parts would not be installed in safety grade applications. This would result in failure to comply with the FCS design basis. Design basis compliance is not assured."*

The team also assessed the adequacy of the extent of condition, extent of causes, and corrective actions (CL Items 3.b.1.1; 3.b.1.2; 3.b.1.3).

The team's assessment of this RCA was based on the evaluation criteria from Section 02.02 of NRC Inspection Procedure 95001, which aligned with this item. The inspection objectives were to:

- Provide assurance that the apparent and contributing causes of risk-significant issues were understood
- Provide assurance that the extent-of-condition and extent-of-cause of risk-significant issues were identified
- Provide assurance that the licensee's corrective actions for risk-significant performance issues were, or will be, sufficient to address the apparent and contributing causes and to preclude repetition

ii. Observations and Findings

<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 this problem using a systematic methodology to identify the root and contributing causes. Specifically, RCA 2012-05615 employed the use of event and causal factor charting, barrier analysis, common factor analysis, and the why staircase. The licensee identified the following as the root cause for why FCS has allowed non-safety-related parts to be installed in safety grade applications:

> *RC-1: Inadequate procedural guidance and an ineffective training/mentoring process have resulted in an ineffective work planning and review process with the potential for non-CQE parts being installed where CQE parts are required.*
>
> (CQE stands for critical quality element and is synonymous with safety-related).

The licensee's RCA also identified the following contributing causes (CC):

> *CC-1: A lack of adequate reference documents and resources/tools for planners, engineers, and maintenance personnel to reference exists.*
>
> *CC-2: Ownership of important resources (Bill of Materials, CQE List, Asset Suite) is not known by Station personnel.*
>
> *CC-3: Overconfidence in Station personnel abilities to accomplish work has resulted in inadequate use of human performance tools and a rationalization that current expectations, standards, and performance are sufficient for Station needs.*
>
> *CC-4: Station personnel were willing to work around Station procedures using "tribal" knowledge (experience) to complete tasks which resulted in a procedure use and adherence issue.*
>
> *CC-5: The CAP has not fully assessed and effectively resolved identified CQE issues.*
>
> *CC-6: A station personnel knowledge gap exists for the CQE classification boundaries and dedication requirements.*

The team determined that these root and contributing causes reasonably explain why the safety-related parts program at FCS failed to maintain design control such that non-safety graded parts have been installed in safety grade applications. However, the team identified that the RCA appeared to be incomplete because it did not address the licensee's ability to properly classify structures, systems, and components as safety-related. NRC's Manual Chapter 0350 Panel FCS Restart Checklist Basis Document, Item 3.b.1, Safety-Related Parts Program, specifically identified that the NRC will assess the licensee's equipment design quality classifications review for inconsistent quality classifications. The licensee performed an operability evaluation regarding piping code of record concerns and plans to review their CQE documentation during their design basis reconstitution.

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 RCA was conducted to a level of detail commensurate with the significance of the problem. Specifically, as discussed above, the licensee conducted this evaluation not only by using event and causal factor charting, barrier analysis, and the why-staircase, but also by conducting interviews, reviewing documents, and attending meetings. The licensee's RCA techniques were generally thorough and identified the root and contributing causes of deficiencies in the safety-related parts program relative to work planning and work control.

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 RCA 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.

The team reviewed the licensee's RCA as it relates to extent of condition and extent of cause.

For extent of condition, the licensee evaluated the extent to which the actual condition exists with other plant processes, equipment, or human performance. The licensee's analysis used the same-same, same-similar, similar-same, and similar-similar evaluation method. The licensee concluded that the extent of condition does exist relative to other processes, procedures, or commitments where nonconformity with established requirements could result in a non-compliance with the FCS design basis. The licensee also found that an extent of condition may exist for nuclear safety culture which has not been fully addressed by causal analysis but can affect the station's commitment to written agreements related to the FCS design basis. The licensee initiated CR 2012-17437 to address this extent of condition issue.

The team noted that the licensee did not specifically document where the actual condition of non-safety-related components may exist in safety-related equipment as part of the extent of condition. This was determined to be a documentation oversight since, through interviews, the team found that the licensee had a comprehensive plan to address this element of extent of condition established under Action Item 29 of CR 2011-09459 and CA-13 of CR 2012-05615. That plan reviewed safety-related WOs for the past two cycles to identify where non-safety parts were inappropriately used in safety-related applications. The team found that these corrective actions would reasonably address any current issues where non-safety-related components were used in safety-related applications. The team determined that while the licensee's strategy to address extent of condition was technically sound, the failure of the RCA to address weaknesses in the ability to classify safety-related components could result in a less than adequate extent of condition review.

For extent of cause, the licensee reviewed the root causes of an identified problem to determine where they may have impacted other plant processes, equipment, or human performance. The licensee's analysis determined that an extent of cause does exist related to the adequacy of non-accredited training programs. The licensee initiated CR 2012-18335 to address the issues identified with non-accredited training.

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 root cause, extent of condition, and extent of cause evaluations appropriately considered the safety culture components as described in IMC 0310. Specifically, the licensee documented their consideration of the IMC 0310 cross-cutting aspects in Attachment 11 of RCA 2012-05615. The licensee identified several cross-cutting aspects in the area of human performance, problem identification and resolution, and other components were applicable to issues related to deficiencies in identifying degraded/nonconforming conditions and operability evaluations. The final evaluation concluded that only a small number of the safety culture attributes were not to be applicable to RCA 2012-05615.

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 root and contributing causes. The team found that the corrective actions addressed the root and contributing causes for why the licensee has allowed non-safety graded parts to be installed in safety grade applications. The team noted that the corrective actions focused primarily on work planning procedure changes and development and implementation of training for work planners. The team also found that Corrective Action 13 of CR 2012-05615 which implemented a review of the past two cycles of safety-related work order adequately addressed the extent of condition relative to where non-safety parts may have been inappropriately used in safety-related applications. The team did note that the licensee's corrective action plan did not include any actions to address weaknesses in the station's ability to classify structures, systems, and components. The team determined that the licensee's corrective actions would only be effective once weaknesses in the ability to classify safety-related components are corrected.

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 work planners. 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. The licensee established, in part, effectiveness reviews consisting of independent self-assessments to determine if the necessary guidance for planners to resolve CQE issues was incorporated into FCS procedures. Additionally, the licensee identified interim and final effectiveness reviews consisting of independent self-assessments to review condition reports and WOs for CQE related issues. The review provided specific performance measure to verify the frequency of CQE related issues is reduced. 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.

iii. Assessment Results

The team concluded that for Root Cause Analysis 2012-05615: the root and contributing causes of risk-significant issues were understood; the extent-of-condition and extent-of-cause of risk-significant issues were identified; and, the licensee's corrective actions for risk-significant performance issues were, or will be, sufficient to address the root and contributing causes.

Restart Checklist items 3.b.1.1, 3.b.1.2, and 3.b.1.3 are closed.

.e Operability Process

Improper evaluations of degraded and/or non-conforming conditions may result in continued operation with a structure, system, or component that is not capable of performing its design function.

(1) Inspection Scope

The team reviewed the licensee’s assessment of the Fundamental Performance Deficiency (FPD) associated with Processes to Meet Regulatory Requirements specifically related to the Operability Determination process. Specifically, the team assessed the RCA for CR 2012-09494 Revision 1, which identified the following programmatic and cultural deficiencies:

- Deficiencies in the accurate identification of current licensing basis degraded/nonconforming conditions
- Operability determinations/functionality assessments are not sufficiently rigorous
- Discrepant conditions are not always resolved in a timely manner commensurate with the safety significance of the condition
- Cause analysis and extent of condition are not consistently rigorous to identify the underlying cause of the equipment’s deficient condition and the broadness impact of the condition
- The characteristics necessary for equipment to be fully qualified are not well understood or applied

The team also assessed the adequacy of the extent of condition, extent of causes, and corrective actions. (Restart Checklist Basis Document Items 3.e.1; 3.e.2; 3.e.3)

The team’s assessment of this FPD was based on the evaluation criteria from Section 02.02 of NRC Inspection Procedure 95001 which align with this item. The inspection objectives were to:

- Provide assurance that the root and contributing causes of risk-significant issues were understood
- Provide assurance that the extent-of-condition and extent-of-cause of risk-significant issues were identified
- Provide assurance that the licensee's corrective actions for risk-significant performance issues were, or will be, sufficient to address the root and contributing causes and to preclude repetition

(2) Observations and Findings

<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 this problem using a systematic methodology to identify the root and contributing causes. Specifically, RCA 2012- 09494 employed the use of barrier analysis to identify applicable causal factors. The licensee further refined the results of the barrier analysis by use of a "Five Whys" analysis to determine the root causes. The licensee then evaluated the cause statements against "cause testing" established in FCS procedures to confirm the root and contributing causes.

The licensee identified the following as root causes for the FPD:

> *RC-1: Leadership has not provided adequate governance and oversight for key regulatory required programs and activities.*
>
> *RC-2: Processes to perform, and support performance of, Degraded/Non-Conforming Condition identification and Operability Determinations are not adequate to ensure consistently accurate and timely determinations.*
>
> *CC-1: The Operating Experience Program permitted a superficial review of NRC Regulatory Issue Summary (RIS) 2005-20 Revision 1.*
>
> *CC-2: Operations leadership did not recognize the risk associated with failing to keep pace with the industry standard for an Operations led organization.*
>
> *CC-3: Knowledge and skills to perform, and support performance of, Degraded/Non-Conforming Condition identification and Operability Determinations are not adequate to ensure consistently accurate and timely determinations.*
>
> *CC-4: Tools used to perform, and support performance of, Degraded/Non-Conforming Condition identification and Operability Determinations are not adequate to ensure consistently accurate and timely determinations.*

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

The licensee's RCA employed various techniques to analyze the events. In general, the quality of analysis was sound and identified several failed barriers in the process for identification of degraded/nonconforming conditions and operability determinations.

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

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

<u>Determine that the root cause evaluation addressed the extent of condition and the extent of cause of the problem</u>.

The team reviewed the RCA as it relates to extent of condition and extent of cause. For extent of condition, the licensee's evaluation determined that an extent of condition for deficiencies in identifying degraded/nonconforming conditions and performance of operability determinations does exist at FCS. Consequently, the licensee concluded that other regulatory-required programs, such as, the operability determination process were not effectively implemented at FCS but the condition was known as documented in CR 2012-08137, Regulatory Processes and Infrastructure. The team generally agreed that the licensee had identified similar processes, such as those documented in CR 2012-08137, which were not being effectively implemented at FCS.

For extent of cause, the licensee identified extent of cause concerns involving inadequacies in reinforcing high standards and accountability which was determined to cross all department and work process boundaries. The licensee addressed the extent of cause through the organizational ineffectiveness RCA performed under CR 2012-03986. The licensee determined that corrective actions taken to address the organizational ineffectiveness extent of cause fully address the extent of cause for CR 2012-09494. The team found that the corrective actions generally addressed the extent of cause related to root cause 1 and 2.

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

The root cause, extent of condition, and extent of cause evaluations appropriately considered the safety culture components as described in IMC 0310. Specifically, the licensee documented their consideration of the IMC 0310 cross-cutting aspects in Attachment 5 of RCA 2012-09494. The licensee identified H.1 Decision Making – Licensee decisions demonstrate that nuclear safety is an overriding priority and O.1 Accountability – Management defines the line of authority and responsibility for nuclear safety as the most applicable safety culture components.

<u>Determine that appropriate corrective actions are specified for each root and contributing cause</u>.

The team reviewed the licensee's corrective actions for each of the root and contributing causes. In general, the corrective actions identified for the root and contributing causes appear to be adequate to resolve the identified causes.

<u>Determine that a schedule has been established for implementing and completing the corrective actions</u>.

The team determined that a schedule has been established for implementing and completing the assigned corrective actions. Most of the corrective actions have been completed.

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

The effectiveness review plan documented is problematic. Specifically, the licensee has not established adequate quantitative or qualitative acceptance criteria measures to assess the effectiveness of each corrective action to prevent recurrence and the corrective actions to prevent recurrence collectively to prevent recurrence of the root causes as required by FCSG-24-5, "Cause Evaluation Manual." Specifically, the current effectiveness review plan would allow inadequate operability calls to not fail the effectiveness review as long as those calls were only on non-safety significant equipment. In this instance the licensee defines safety significant equipment as that which would put the station into a Technical Specification action statement or change the Equipment out of service "Risk" color. In addition the inspectors are not aware of a licensee mechanism to track this required information. These observations were discussed with the licensee.

(3) Assessment Results

The team concluded that for Root Cause Analysis 2012-9494: the root and contributing causes of risk-significant issues were understood; the extent-of-condition and extent-of-cause of risk-significant issues were identified; and, the licensee's corrective actions for risk-significant performance issues were, or will be, sufficient to address the root and contributing causes.

Restart Checklist Items 3.e.1, 3.e.2, and 3.e.3 are closed.

4OA5 Other Activities

On April 11, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed a reactive inspection in accordance with NRC Inspection Procedure 93812, "Special Inspection," at your Fort Calhoun Station. This special inspection was conducted to gather information associated with the improper design specifications associated with the raw water pump anchor bolts. Inspection Report 05000285/2013-012, issued on May 24, 2013 (ML13144A772) documents the results of this inspection. Documented in this report are two apparent violations (AV) that were issued pending further evaluation by the licensee. The purpose of this section is document closure of these two AVs.

.1 (Closed) Apparent Violation 05000285/2013012-08: Failure to Adequately Design Anchorage for Containment Spray and Raw Water System Pipe Supports

a. Inspection Scope

The inspection report documented an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure the adequacy of the anchorage for several raw water system and containment spray system pipe supports. Specifically the anchorage design was non-conservative with respect to the design basis requirements. This issue was and apparent violation because the final safety significance was to be determined pending additional analysis of the as-found configuration of the anchorage and associated pipe supports by the licensee.

b. Findings

Failure to Adequately Design Anchorage for Containment Spray and Raw Water System Pipe Supports

Introduction. The inspection team identified several examples of a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” for the failure to ensure the adequacy of the anchorage for several raw water system and containment spray system pipe supports. Specifically the anchorage design was non-conservative with respect to the design basis requirements.

Description. During a previous inspection, the NRC reviewed multiple calculations for pipe supports on the raw water and containment spray systems and found that the calculations had several errors related to the design requirements for anchorage. The NRC issued an apparent violation AV 05000285/2013012-08, “Failure to adequately design anchorage for containment spray and raw water system pipe supports” in NRC Inspection Report 05000285/2013-012 (ML 13144A772).

The licensee performed an operability determination for the affected calculations and found that the anchorage for the raw water and containment spray piping supports were operable. The NRC reviewed the evaluations and concluded that reasonable assurance of operability existed for the affected components.

Analysis. The inspectors determined that the failure to ensure adequacy of the anchorage of the aforementioned Containment Spray Pipe Supports and Raw Water Pipe Supports was not in accordance with design basis requirements and was a performance deficiency. The performance deficiency was determined to be more than minor because it required calculations to be re-performed to prove the system was operable, and it was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of the containment spray system and raw water system.

Using Inspection Manual Chapter 0609, Attachment 4 “Initial Characterization of Findings,” and Appendix A “The Significance Determination Process (SDP) for findings at-power,” both dated 6/19/12, the inspectors determined the performance deficiency affected the mitigating systems cornerstone and screened to Green because the finding affected the design and qualification of a mitigating SSC but remained operable. The inspectors used the at-power SDP because the condition existed since construction and while the plant was predominantly at power.

The inspectors determined there was no cross-cutting aspect associated with this finding because the calculations were from the 1980’s and therefore were not reflective of current performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control" states, in part, that the design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to this requirement the inspectors identified that calculations FC00607, FC01785, FC01786, FC01791, FC01864, FC01691, FC01902, FC02409, FC02412, FC04228, FC02433, FC02436, and FC02425 for the raw water and containment spray systems failed to ensure adequacy of the design. Specifically, these anchorage calculations did not conform to applicable design requirements from approximately 1980 until June 2013.

The licensee entered these issues into the corrective action program as CR 2013-05304 and performed an operability determination as immediate actions. Long term actions to resolve the errors in the calculations are also implemented by the referenced CR. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. (NCV 05000285/2014002-08, "Failure to Adequately Design Anchorage for Containment Spray and Raw Water System Pipe Supports").

.2 (Closed) Apparent Violation 05000285/2013012-09: Failure to Adequately Implement Design Requirements for Containment Air Cooler Pipe Supports

a. Inspection Scope

The inspection report documented an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure the adequacy of the U-bolts for Containment Air Cooler pipe supports VAS-1 and VAS-2. This issue was an apparent violation because the final safety significance was to be determined pending additional analysis of the as-found configuration of the condensate drain line and associated pipe supports by the licensee.

b. Findings

Failure to Adequately Implement Design Requirements for Containment Air Cooler Pipe Supports

Introduction. The NRC identified a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to ensure the adequacy of the U-bolts for containment air cooler pipe supports VAS-1 and VAS-2. Specifically the U-bolt design was non-conservative with respect to the design basis requirements.

Description. During a previous inspection, the NRC reviewed calculations for VAS-1 and VAS-2 pipe supports on the containment air cooling systems and found that the calculations had an error in the design requirements for U-bolts. Specifically, calculation FC05918 for the VAS-1 and VAS-2 U-bolts did not consider two-directional applied loading, it only considered tensile loads. The NRC issued an apparent violation AV 05000285/2013012-09, "Failure to adequately implement design requirements for containment air cooler pipe supports" in NRC Inspection Report 0500285/2013-012 (ML 13144A772).

Analysis. The inspectors determined that the failure to ensure adequacy of the U-bolts for containment air cooler pipe supports VAS-1 and VAS-2 in accordance with design basis requirements was a performance deficiency.

The performance deficiency was determined to be more than minor because it required calculations to be re-performed to prove the system was operable, and it was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of several safety injection tank valves. Specifically, the one-directional U-bolts for VAS-1 and VAS-2 are not designed to withstand two-directional loading and the condensate drain piping line has the potential to adversely impact the safety injection tank discharge isolation valves HCV-2984 and HCV-2794 during a design basis event.

The licensee updated calculation FC05918 and provided an operability evaluation to address the degraded condition. The inspectors reviewed the information and found the analysis adequately supported the operability of the affected equipment.

Using Inspection Manual Chapter 0609, Attachment 4 “Initial Characterization of Findings,” and Appendix A, “The Significance Determination Process (SDP) for findings at-power,” both dated 6/19/12, the inspectors determined performance deficiency affected the mitigating systems cornerstone and screened to Green because the finding affected the design and qualification of a mitigating SSC but remained operable. The inspectors used the at-power SDP because the condition existed since construction and while the plant was predominantly at power.

The inspectors determined there was no cross-cutting aspect associated with this finding because the calculation was from the 1980s, therefore was not reflective of current performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control” states, in part, that the design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to this requirement, the inspectors identified that calculation FC05918, from 1992 until May 2013, failed to ensure adequacy of the design. Specifically, the calculation did not conform to the U-bolt requirements by applying two-directional loading to a U-bolt restraint that is qualified for only one-directional loading. The licensee revised the calculation to support operability. In addition, the licensee generated engineering change EC59570 to fix the degraded VAS-1 and VAS-2 supports. The licensee entered these issues into the corrective action program as CR 2013-03722. This violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. (NCV 05000285/2014002-09, “Failure to Adequately Implement Design Requirements for Containment Air Cooler Pipe Supports”).

4OA6 Meetings, Including Exit

Exit Meeting Summary

On February 25, 2014, the inspectors presented the inspection results to Mr. M. Prospero, Plant Manager, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Anderson, Manager, Design Engineering
D. Bakalar, Manager, Security
J. Bousum, Manager, Emergency Planning and Administration
C. Cameron, Supervisor Regulatory Compliance
L. Cortopassi, Site Vice President
M. Ferm, Manager, System Engineering
K. Ihnen, Manager, Site Nuclear Oversight
T. Lindsey, Director, Training
E. Matzke, Senior Licensing Engineer, Regulatory Assurance
J. McManus, Manager, Engineering Programs
B. Obermeyer, Manager, Corrective Action Program
M. Prospero, Plant Manager
T. Orth, Director, Site Work Management
S. Shea, Supervisor, Operations Training
T. Simpkin, Manager, Site Regulatory Assurance
S. Swanson, Director, Operations

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000285/2014002-05	VIO	Untimely Submittal of Required Licensee Event Reports (Section 4OA3.4)
05000285/2013-015-01	LER	Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82 (Section 4OA3.6)
05000285/2013-016-00	LER	Reporting of Additional High Energy Line Break Concerns (Section 4OA3.7)
05000285/2014002-06	VIO	Failure to Restore Compliance for Containment Spray Runout Conditions (Section 4OA3.8)
05000285/2013-019-00	LER	Non-Seismic Circulating Water Pipe Could Disable Raw Water Pumps (Section 4OA3.9)

Closed

05000285/2012-013-00	LER	Inadequate Calculation of Uncertainty Results a Technical Specification Violation (Section 4OA3.1)
05000285/2013-003-01	LER	Calculations Indicate the HPSI Pumps will Operate in Run-out During a DBA (Section 4OA3.2)
05000285/2013-007-01	LER	Containment Air Cooling Units (VA-16A/B) Seismic Criteria (Section 4OA3.3)

Closed

05000285/2013-010-01	LER	HPSI Pump Flow Imbalance (Section 4OA3.4)
05000285/2013-015-00	LER	Unqualified Coating used as a Water Tight Barrier in Rooms 81 and 82 Section 4OA3.5)
05000285/2013-017-00	LER	Containment Spray Pump Design Documents do not Support Operation in Runout (Section 4OA3.8)
05000285/2013012-08	AV	Failure to Adequately Design Anchorage for Containment Spray and Raw Water System Pipe Supports (Section 4OA5.1)
05000285/2013012-09	AV	Failure to Adequately Implement Design Requirements for Containment Air Cooler Pipe Supports (Section 4OA5.2)

Opened and Closed

05000285/2014002-01	NCV	Failure to Make Required 10 CFR 50.46 Report Within Required Time (Section 4OA3.2)
05000285/2014002-02	NCV	Failure to Translate HPSI Pump Design Requirements to Design Documents (Section 4OA3.2)
05000285/2014002-03	NCV	Failure to Maintain Design Control of HPSI Injection Valve (Section 4OA3.4)
05000285/2014002-04	NCV	Failure to Request a License Amendment for Required Change to Technical Specifications (Section 4OA3.4)
05000285/2014002-07	NCV	Inadequate 10 CFR 50.59 Screening for Containment Spray Design Change (Section 4OA3.8)
05000285/2014002-08	NCV	Failure to Adequately Design Anchorage for Containment Spray and Raw Water System Pipe Supports (Section 4OA5.1)
05000285/2014002-09	NCV	Failure to Adequately Implement Design Requirements for Containment Air Cooler Pipe Supports (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Procedures

Number	Title	Revision
	FCS Technical Specifications	
FC06747	SI Pump Room (Roon 21 & 22) Heat-up During Pump Operation	6
USAR 9.10	Auxiliary Systems – Heating, Ventilating and Air Conditioning System	32

Condition Reports (CRs)

2013-21373	2013-23302	2014-00211	2014-00203	2014-00373

Section 1RO5: Fire Protection

Procedures

Number	Title	Revision
OP-MW-201-0007	Fire Protection System Impairment Control	7
SO-G-102	Fire Protection Program Plan	17
SO-G-103	Fire Protection Operability Criteria and Surveillance Requirements	27
SO-G-28	Station Fire Plan	86
SO-G-91	Control and Transportation of Combustible Materials	30

Miscellaneous Documents

Number	Title	Revision
EA-FC-97-001	Fire hazards Analysis Manual	17
FC05814	UFHA Combustible Loading Calculation	11
USAR 9.11	Updated Safety Analysis Report, Fire Protection Systems	24

Section 1R06: Flood Protection Measures

Procedures

Number	Title	Revision
SO-G-124	Flood Barrier Impairment	R4a

Condition Reports (CRs)

2014-00329

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance

Procedures

Number	Title	Revision
AOP-17	Loss of Instrument Air	15

Procedures

Number	Title	Revision
AOP-20	Loss of Bearing Water Cooling	5
AOP-30	Emergency Fill of Emergency Feedwater Storage Tank	12a
AOP-36	Loss of Spent Fuel Pool Cooling	10
EOP-00	Standard Post Trip Actions	31
EOP-01	Reactor Trip Recovery	14a

Miscellaneous Documents

Number	Title	Date
	Simulator Fidelity Issues	January 17, 2014
	Simulator Walkdown Cycle 14-1	January 18, 2014
Simulator Scenario Guide 82103e	Loss of SFPC, Loss of Bearing Water and Emergency Fill of the EFWST	January 2, 2014

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision
FCSG-19	Performing Risk Assessments	17
SO-M-100	Conduct of Maintenance	57b
SO-M-101	Maintenance Work Control	103

Section 1R15: Operability Determinations and Functionality Assessments

Procedures

Number	Title	Revision
FC-1137	Acceptance fro Operability (OPSAC)	21
OP-FC-108-115	Operability Determinations	0a
OP-FC-108-115-1001	Operability Evaluation Asset Suite Engineering Change Desktop Guide	0
OP-FC-108-115-1002	Supplemental Consideration for On-Shift Immediate Operability Determinations	0

Procedures

Number	Title	Revision
OP-FC-108-115-1003	Operability Determination Oversight and Monitoring	0

Calculations

Number	Title	Revision
FC08167	Acceptable Minimum Wall Thickness for Raw Water Piping Downstream of Component Cooling Water Heat Exchanger AC-1D	0

Miscellaneous Documents

Number	Title	Date
N-513-3	Cases of ASME Boiler and Pressure Vessel Code, “Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping”	January 26, 2009

Condition Reports (CRs)

2012-15755	2011-5244	2014-01963	2013-22937	2013-23166

Section 1R19: Post-Maintenance Testing

Procedures

Number	Title	Revision
EM-PM-EX-1000	480 Volt Motor Inspection	24
FC05571	HCV-2504A Leakage Rate compared to allowable limits	0
IC-CP-01-1112	Calibration of Auxiliary Feedwater Pump FW-54 Suction Flow Loop F-1112	3
IC-CP-01-1117	Auxiliary Feedwater Pump FW-54 Discharge Flow Indication	3
MM-PM-AFW-0002	Diesel Engine FW-56 Fluid Maintenance	8
MM-PM-AFW-0005	Diesel Engine FW-56 Maintenance	7
OP-PM-AFW-0004	Third Auxiliary Feedwater Pump Operability Verification	39
PBD-5	Containment Leak Rate	18
QC-ST-SL-3001	Primary Sample System RCS Sample Lines Pressure Test	6

Condition Reports (CR)

2014-00522

Work Orders (WO)

506373	424138	472519	476594	476967
480835	437931	481784	481785	490755

Section 1R22: Surveillance Testing

Procedures

Number	Title	Revision
IC-ST-IA-3009	Operability Test of IA-YCV-1045-C and Close Stroke Test of YCV-1045	24
OP-ST-AFW-3011	Auxiliary Feedwater Pump FW-10, Steam Isolation Valve, and Check Valve Tests	20
OP-ST-RC-3001	Reactor Coolant System (RCS) Leak Rate Test	36
OP-ST-RW-3021	AC-10C Raw Water Pump Quarterly Inservice Test	39

Drawings

Number	Title	Revision
11405-M-253	Steam Generator and Blowdown Flow Diagram P&ID	98

Condition Reports (CR)

2012-15755	2014-01943	2014-01970	2014-01969

Work Orders (WO)

492131	491025

Section 4OA2: Problem Identification and Resolution (71152)

Procedures

Number	Title	Revision
FCSG-24-1	Condition Report Initiation	6
FCSG-24-3	Condition Report Screening	12a
FCSG-24-4	Condition Report and Cause Evaluation	8a

Section 4OA2: Problem Identification and Resolution (71152)

Procedures

Number	Title	Revision
FCSG-24-6	Corrective Action Implementation and Condition Report Closure	12a
SO-R-2	Condition Reporting and Corrective Action	53b

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures

Number	Title	Revision
NOD-QP-3	10 CFR 50.59 and 10 CFR 72.48 Reviews	37
FCSG-23	10 CFR 50.59 Resource Manual	8
SO-R-1	Reportability Determinations	26 - 32

Condition Reports (CR)

2013-09949	2008-1666	2013-08300	2013-22007	2012-03796
2013-10910	2008-1683	2013-19722	2014-01029	2012-03796
2013-12508	2013-15047	2013-16417	2013-17630	2013-09949
2014-00958	2014-01358	2013-15442	2013-16241	2014-00674
2013-02100	2013-14177	2014-01629	2012-09494	2012-08137
2012-03986	2012-05615	2012-17437	2011-09459	2012-18.335
2012-05615	2011-09956			

Other Documents

Number	Title	Revision / Date
	DEN Memorandum, “90% SMART Meeting Held on Wednesday September 18, 2013 for EC 59874.’HPSI Pump Runout Orifice Plates for SI-2A, SI-2B and SI-2C’ Revision 1,”	September 19, 2013
EA 13-023	Fort Calhoun SBLOCA Analysis with Reduced HPSI Flow (AREVA Calc. 32-9130020-001)	August 16, 2013

Other Documents

Number	Title	Revision / Date
EA 13-028	Fort Calhoun Safety Analysis Evaluation with Reduced HPSI Flow (AREVA Calc. 51-9130106-002)	August 16, 2013
EC 30663	GSI-191 Implementation	0
EC 59874	HPSI Pump Runout Orifice Plates for SI-2A, SI-2B and SI-2C, Rev 1 Kickoff Meeting	July 30, 2013
EC 59874	HPSI Pump Runout Orifice Plates for SI-2A, SI-2B and SI-2C	0,1
EC 62416	Temporary Modification – Throttle Discharge Valves HCV-2958, HCV-2968, and HCV-2978	1,2
FC 07470	Minimum Pump Performance Curve for HPSI Pump	0
FC-68C	Applicability Determination, “HPSI Pump Runout, SI-2A, SI-2B and SI-2C Part 3 of 3 (HPSI Loop Flow Balancing)”	October 2, 2013
LER 2013-010-0	HPSI Pump Flow Imbalance	July 2, 2013
LER 2013-010-1	HPSI Pump Flow Imbalance	October 23, 2013
LIC 13-0133	30-Day Report of a Significant Change in the Loss-of-Coolant Accident (LOCA)/Emergency Core Cooling System (ECCS) Models Pursuant to 10 CFR 50.46	September 20, 2013
LIC 77-0090	OPPD Letter to NRC	August 22, 1977
NEI 0705	10 CFR 50.46 Reporting Guidelines	July 2008
NRC 77-0060	NRC Letter to OPPD	June 30, 1977

Section 4OA5: Other Activities

Condition Reports (CR)

2013-3722 2013-5304