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

November 10, 2016

Mr. Oscar A. Limpias
Vice President-Nuclear and CNO
Nebraska Public Power District
Cooper Nuclear Station
72676 648A Avenue
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION – NRC INTEGRATED INSPECTION REPORT 05000298/2016003

Dear Mr. Limpias:

On September 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. On October 12, 2016, the NRC inspectors discussed the results of this inspection with Mr. Ken Higginbotham, General Manager Plant Operations, and other members of your staff. The Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented three findings of very low safety significance (Green) in this report. All of these findings involved violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest 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 Cooper Nuclear 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 Cooper Nuclear 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

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Sincerely,

/RA/

Greg Warnick, Branch Chief
Project Branch C
Division of Reactor Projects

Docket No. 50-298
License No. DPR-46

Enclosure:
Inspection Report 05000298/2016003
w/ Attachment:
1. Supplemental Information
2. Inservice Inspection Document Request

cc w/ encl: Electronic Distribution

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Letter to Oscar A. Limpias from Greg Warnick dated November 10, 2016

SUBJECT: COOPER NUCLEAR STATION – NRC INTEGRATED INSPECTION REPORT 05000298/2016003

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000298
License:	DPR-46
Report:	05000298/2016003
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Ave Brownville, NE
Dates:	July 1 through September 30, 2016
Inspectors:	P. Voss, Senior Resident Inspector C. Henderson, Resident Inspector J. Drake, Senior Resident Inspector M. Schneider, Senior Resident Inspector R. Latta, Senior Reactor Inspector C. Young, Senior Project Engineer
Approved By:	Greg Warnick Chief, Project Branch C Division of Reactor Projects

SUMMARY

IR 05000298/2016003; 07/01/2016 – 09/30/2016; Cooper Nuclear Station; Maint. Risk Assess. & Emergent Work Control, Operability Determinations & Functionality Assess., Problem Ident. & Resolution.

The inspection activities described in this report were performed between July 1 and September 30, 2016, by the resident inspectors at the Cooper Nuclear Station and inspectors from the NRC's Region IV office. Three findings of very low safety significance (Green) are documented in this report. All of these findings involved violations of NRC requirements. 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, "Aspects within the Cross-Cutting Areas." Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to correctly translate the design basis into maintenance instructions for reactor equipment cooling pump B. Specifically, on August 7, 2016, during corrective maintenance following a pump trip, the licensee developed work instructions that installed incorrectly sized thermal overload relay heaters, introducing a condition that was nonconforming with the design basis. Immediate corrective actions included replacing the incorrectly sized heaters, performing a failure modes analysis to determine the actual cause of the pump trip, and replacing the thermal overload relay. The issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2016-04649.

  The licensee's failure to correctly translate the design basis into work instructions for thermal overload relay heaters associated with reactor equipment cooling pump B was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems Cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency resulted in a challenge to operability, a 2-day extension of pump out of service time, and an initial failure to pursue identification of the actual cause of the August 6, 2016, pump trip. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding had very low safety significance (Green) because: it was not a design deficiency; did not represent a loss of system and/or function; did not represent an actual loss of function of at least a single train for longer than its technical specification allowed outage time; and did not result in the loss of a high safety-significant non-technical specification train. The finding had a cross-cutting aspect in the area of problem identification and resolution associated with evaluation. Specifically, the licensee failed to thoroughly evaluate the reactor equipment cooling pump issues to ensure that the resolution addressed the cause and extent of condition commensurate with the safety significance [P.2]. (Section 1R13)

- Green. The inspectors identified a non-cited violation of Technical Specification 3.5.1, "Emergency Core Cooling Systems and Reactor Core Isolation Cooling System," for the licensee's failure to evaluate and implement adequate internal flooding protection compensatory measures to maintain low pressure coolant injection/spray systems operable. Specifically, from July 11, 2016, to July 15, 2016, the licensee placed the torus area and reactor building floor drain valve switches in the open position, defeating the automatic flood protection function credited in the licensee's internal flooding analysis, and failed to implement adequate compensatory measures. These barriers were credited to protect the Division I core spray and Division I residual heat removal systems from flooding caused by a high-energy line break from the 18-inch feedwater line contained in the steam tunnel. This resulted in inoperability of both systems for a period greater than allowed by the plant's technical specifications. Immediate corrective actions included repairing the fire detection equipment that prompted the configuration; restoring torus and reactor building floor drain automatic flood protection functions; and initiating a condition report to evaluate the technical specification impacts. The licensee entered this deficiency into their corrective action program for resolution as Condition Report CR-CNS-2016-06056.

  The licensee's failure to maintain emergency core cooling system low pressure injection/spray systems operable for internal flooding hazards, in violation of Technical Specification 3.5.1, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the human performance attribute of the Mitigating Systems Cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, without automatic flood barrier protection or an associated compensatory measure, the Division I core spray and Division I residual heat removal systems were inoperable for a high-energy line break from the 18-inch feedwater line. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding required a detailed risk evaluation because it involved two separate safety systems being out-of-service for greater than their technical specification allowed outage time. A senior reactor analyst performed a detailed risk evaluation for this issue and determined that the finding had very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance associated with documentation because the licensee failed to create and maintain complete, accurate, and up-to-date documentation. Specifically, Station Procedure 2.3_FP-1 contained inappropriate directions to defeat the flood barriers because it did not recognize the credited automatic flood protection function provided by the valves; thus, operations personnel failed to recognize the need for compensatory measures [H.7]. (Section 1R15)

- Green. The inspectors reviewed a self-revealing, non-cited violation of Technical Specification 5.4.1.a for the licensee's failure to maintain a procedure required by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, the licensee failed to maintain Station Procedure 7.2.15, "Service Water Pump Column Maintenance and Bowl Assembly Replacement," Revision 37, in accordance with the documented vendor manual service water pump shaft tolerances. This resulted in an unbalanced condition for service water pump B at running speed and ultimately caused an enclosing tube failure. The failure of the enclosing tube caused a step change in gland water flow, which resulted in the licensee declaring service water pump B inoperable during surveillance testing. The immediate corrective action was to evaluate the cause of the failure and conduct repairs to the pump. The licensee entered this deficiency into the corrective action program as

Condition Report CR-CNS-2016-02342, and initiated an apparent cause evaluation to investigate this condition.

The licensee's failure to maintain Station Procedure 7.2.15 in accordance with documented vendor manual service water pump shaft tolerances, in violation of Technical Specification 5.4.1.a, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the procedural quality attribute of the Mitigating Systems Cornerstone, and adversely affected the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure of the enclosing tube caused a step change in gland water flow which required the licensee to enter an unplanned limiting condition for operation to conduct repairs. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, inspectors determined that the finding had very low significance (Green) because: it was not a design deficiency; did not represent a loss of system and/or function; did not represent an actual loss of function of at least a single train for longer than its technical specification allowed outage time; and did not result in the loss of a high safety-significant non-technical specification train. A cross-cutting aspect was not assigned to this finding because the performance deficiency occurred in 1997 and, therefore, was not indicative of current licensee performance. (Section 4OA2)

PLANT STATUS

The Cooper Nuclear Station began the inspection period at full power. On September 14, 2016, the licensee lowered reactor power to approximately 50 percent in order to repair a reactor recirculation motor generator ventilation isolation valve that failed stroke time surveillance testing. Repairs were completed during the down power and the plant returned to full power on September 15, 2016. On September 24, 2016, Cooper Nuclear Station shut down to commence the 2016 refueling outage. The plant remained shutdown for the remainder of the inspection period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Summer Readiness for Offsite and Alternate AC Power Systems

a. Inspection Scope

On September 8, 2016, the inspectors completed an inspection of the station's off-site and alternate-ac power systems. The inspectors inspected the material condition of these systems, including transformers and other switchyard equipment to verify that plant features and procedures were appropriate for operation and continued availability of off-site and alternate-ac power systems. The inspectors reviewed outstanding work orders and open condition reports for these systems. The inspectors walked down the switchyard to observe the material condition of equipment providing off-site power sources. The inspectors assessed corrective actions for identified degraded conditions. The inspectors verified that the licensee's procedures included appropriate measures to monitor and maintain availability and reliability of the off-site and alternate-ac power systems.

These activities constituted one sample of summer readiness of off-site and alternate-ac power systems, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

On July 25, 2016, the inspectors completed an inspection of the station's readiness for seasonal extreme weather conditions. The inspectors reviewed the licensee's adverse weather procedures for seasonal high temperatures and evaluated the licensee's implementation of these procedures. The inspectors verified that prior to the onset of hot weather, the licensee had corrected weather-related equipment deficiencies identified during the previous hot weather season.

The inspectors selected two risk-significant systems that were required to be protected from seasonal high temperatures:

- Control room
- Cable spreading room

The inspectors reviewed the licensee’s procedures and design information to ensure the systems would remain functional when challenged by adverse weather. The inspectors verified that operator actions described in the licensee’s procedures were adequate to maintain readiness of these systems. The inspectors walked down portions of these systems to verify the physical condition of the adverse weather protection features.

These activities constituted one sample of readiness for seasonal adverse weather, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

.3 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

On July 13, 2016, the inspectors completed an inspection of the station’s readiness for impending adverse weather conditions. The inspectors reviewed plant design features, the licensee’s procedures to respond to severe thunderstorms and high winds, and the licensee’s planned implementation of these procedures. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. The inspectors walked down plant equipment during and after the severe weather passed through and assessed impacts to the plant.

These activities constituted one sample of readiness for impending adverse weather conditions, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walk-Down

a. Inspection Scope

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

- August 31, 2016, Essential ventilation system
- September 15, 2016, Residual heat removal containment spray
- September 28, 2016, Residual heat removal shutdown cooling

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 three partial system walk-down samples, as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

.2 Complete Walk-Down

a. Inspection Scope

On September 15, 2016, the inspectors performed a complete system walk-down inspection of the residual heat removal system. The inspectors reviewed the licensee's procedures and system design information to determine the correct system lineup for the existing plant configuration. The inspectors also reviewed outstanding work orders, open condition reports, in-process design changes, temporary modifications, and other open items tracked by the licensee's operations and engineering departments. The inspectors then visually verified that the system was correctly aligned for the existing plant configuration.

These activities constituted one complete 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 four plant areas important to safety:

- July 21, 2016, Reactor building controlled corridor, 903 feet elevation, Fire Area CB-A, Zone 7B
- August 2, 2016, Turbine building controlled corridor, 882 feet elevation, Fire Area TB-A, Zone 11F
- September 13, 2016, Reactor building northwest quad, 859 feet elevation, Fire Area RB-CF, Zone 1C
- September 13, 2016, Reactor building residual heat removal heat exchanger room A, 931 feet elevation, Fire Area RB-M, Zone 2B

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 four quarterly inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

.2 Annual Inspection

a. Inspection Scope

This evaluation included observation of an unannounced fire drill for a fire in the station startup service transformer on August 24, 2016.

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.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

On July 21, 2016, the inspectors completed an inspection of underground bunkers susceptible to flooding. The inspectors selected four underground bunkers that contained risk-significant or multiple-train cables whose failure could disable risk-significant equipment:

- Manhole C1
- Manhole C2
- Manhole P1
- Manhole P2

The inspectors observed the material condition of the cables and splices contained in the bunkers and looked for evidence of cable degradation due to water intrusion. The inspectors verified that the cables and vaults met design requirements.

These activities constituted completion of one bunker/manhole sample, as defined in Inspection Procedure 71111.06.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Non-destructive Examination Activities and Welding Activities

a. Inspection Scope

The inspectors directly observed the following nondestructive examinations:

SYSTEM	COMPONENT IDENTIFICATION	EXAMINATION TYPE
Main Steam	MSH-157A	Visual Test-3
High Pressure Core Injection	HPCI-MP-S1	Visual Test-3
High Pressure Core Injection	HPCI-BP-S1	Visual Test-3
High Pressure Core Injection	HPH-6	Visual Test-3
High Pressure Core Injection	RFH-41	Visual Test-3
Reactor Vessel	NVIR-BD-N3A	Visual Test-1
Reactor Feedwater	Pipe Weld 24	Ultrasonic Test
Reactor Feedwater	Pipe Weld 24	Ultrasonic Test

The inspectors reviewed records for the following nondestructive examinations:

SYSTEM	COMPONENT IDENTIFICATION	EXAMINATION TYPE
Service Water	SW-E-3-2851-3 Elbow	Ultrasonic Testing
Service Water	SW-E-9-2851-2 Elbow	Ultrasonic Testing
Service Water	SW-Z1-2852-9 Pipe	Ultrasonic Testing
Service Water	SW-Z4-2851-7 Pipe	Ultrasonic Testing
Service Water	SW-DG-1-T-1Tee	Ultrasonic Testing

During the review and observation of each examination, the inspectors observed whether activities were performed in accordance with the ASME Code requirements and applicable procedures. The inspectors reviewed 12 indications that were previously examined, and observed whether the licensee evaluated and accepted the indications in accordance with the ASME Code and/or an NRC approved alternative. The inspectors also reviewed the qualifications of all nondestructive examination technicians performing the inspections to determine whether they were current.

The inspectors directly observed a portion of the following welding activities:

SYSTEM	WELD IDENTIFICATION	WELD TYPE
Condenser	CW-V-74 Weld 4	Gas Tungsten Arc Weld
Flex Well Transfer	CH-S-1039 Weld 6	Gas Tungsten Arc Weld

The inspectors reviewed records for the following welding activities:

SYSTEM	WELD IDENTIFICATION	WELD TYPE
Service Water	SW-V-127 Pipe Weld 1 and 2	Gas Tungsten Arc Weld
Reactor Feedwater	HPCI·RO•I35 Orifice Weld 1 and 2	Gas Tungsten Arc Weld

The inspectors reviewed whether the welding procedure specifications and the welders had been properly qualified in accordance with ASME Code Section IX requirements. The inspectors also determined whether the essential variables were identified, recorded in the procedure qualification record, and formed the bases for qualification of the welding procedure specifications.

These activities constituted completion of one inservice inspection sample, as defined in Inspection Procedure 71111.08.

b. Findings

No findings were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed 16 condition reports which dealt with inservice inspection activities and found the corrective actions for inservice inspection issues were appropriate. From this review the inspectors concluded that the licensee has an appropriate threshold for entering inservice inspection issues into the corrective action program and has procedures that direct a root cause evaluation when necessary. The licensee also has an effective program for applying industry inservice inspection operating experience. Specific documents reviewed during this inspection are listed in the attachment.

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 August 2, 2016, the inspectors observed an evaluated simulator scenario performed by an operating crew. The inspectors assessed the performance of the operators and the evaluators' critique of their performance. The inspectors also assessed the modeling and performance of the simulator during the requalification activities.

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

b. Findings

No findings were identified.

.2 Review of Licensed Operator Performance

a. Inspection Scope

On September 24, 2016, the inspectors observed the performance of on-shift licensed operators in the plant's main control room. At the time of the observations, the plant was in a period of heightened activity due to reactor plant shutdown for Refueling Outage 29. The inspectors observed the operators' performance of the following activities:

- Rod manipulation, including the pre-job brief
- Planned scram of the reactor, including the pre-job brief
- Plant cooldown, including the pre-job brief

In addition, the inspectors assessed the operators' adherence to plant procedures, including the conduct of operations procedure and other operations department policies.

These activities constituted completion of one quarterly licensed operator performance sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed two instances of degraded performance or condition of safety-related structures, systems, and components (SSCs):

- July 22, 2016, High pressure coolant injection, for two failures of the auxiliary lube oil pump

- September 19, 2016, Diesel generator 1 exhaust fan, for multiple failures of the exhaust dampers to the open condition

The inspectors reviewed the extent of condition of possible common cause SSC failures and evaluated the adequacy of the licensee's corrective actions. The inspectors reviewed the licensee's work practices to evaluate whether these may have played a role in the degradation of the SSCs. The inspectors assessed the licensee's characterization of the degradation in accordance with 10 CFR 50.65 (the Maintenance Rule), and verified that the licensee was appropriately tracking degraded performance and conditions in accordance with the Maintenance Rule.

These activities constituted completion of two maintenance effectiveness samples, as defined in Inspection Procedure 71111.12.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed four risk assessments performed by the licensee prior to changes in plant configuration and the risk management actions taken by the licensee in response to elevated risk:

- July 24, 2016, Standby liquid control pump A maintenance window
- August 12, 2016, Reactor equipment cooling pump B trip
- August 16, 2016, Yellow risk window for RHR-MOV-39B conduit modification
- August 25, 2016, Station startup service transformer outage for relay testing

The inspectors verified that these risk assessments were 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 assessments and verified that the licensee implemented appropriate risk management actions based on the results of the assessments.

These activities constituted completion of four maintenance risk assessment inspection samples, as defined in Inspection Procedure 71111.13.

b. Findings

Introduction. The inspectors identified a Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to correctly translate the design basis into maintenance instructions for reactor equipment cooling (REC) pump B. Specifically, on August 7, 2016, during corrective maintenance following an REC pump B trip, the licensee developed work instructions that installed incorrectly sized thermal overload (TO) relay heaters, introducing a condition that was nonconforming with the design basis.

Description. On Saturday, August 6, 2016, REC pump B unexpectedly tripped following an inservice testing surveillance run. The pump had been in service for approximately 2 hours when it tripped. Upon discovery, the licensee entered Limiting Condition for Operation 3.7.3, Condition B, for the inoperable REC pump. During investigation, the licensee found that the TO relay for the pump had tripped. The licensee determined that the TO relay had undersized TO heaters installed, which had caused the pump to trip early. These heaters, small metal relay inserts, are designed to trip the TO relay and shut down the pump after a specified amount of heat is detected as a result of unexpectedly high pump motor current. The licensee determined that the pump motor had been evaluated to have FH89 style TO heaters installed (rated for a 93-101 amp motor). The licensee had found that the pump instead had FH88 heaters installed (rated for a smaller 85-92 amp motor). As a result, the licensee concluded that the REC pump had tripped early due to the undersized heaters. Based on this conclusion, the licensee replaced the TO heaters with the FH89 style and declared the pump operable on the morning of Sunday, August 8, 2016.

During follow-up on August 9, 2016, the inspectors learned that the licensee had concluded both TO heater sizes had been evaluated by Engineering as acceptable for usage for the REC pump B. In addition, the inspectors learned that the other three REC pumps were required to use the smaller FH88 sized heaters. The inspectors questioned whether the heater sizing was truly the cause of the REC pump trip if both heater sizes had been evaluated as acceptable for the pump. The inspectors also questioned why the three other REC pump motors would have a different configuration than the REC pump B motor.

While researching the inspector's questions, engineering personnel discovered that the repair the site had made over the weekend was incorrect. The TO FH88 heater had actually been the correct component installed. During the weekend response to the pump trip, rather than performing a thorough review of the equipment failure, the licensee had relied on experience with a previous 2012 pump failure to prematurely draw conclusions about the failure mechanism. In addition, site personnel had referred to an old preventative maintenance work instruction, which had not been updated since the pump motor was replaced in 2013, and came to the incorrect conclusion regarding the need for the larger heaters. As a result, the incorrect FH89 heater size had been installed over the weekend. This component was nonconforming with design basis calculation NEDC 91-184, Revision 4C2, which required utilization of the FH88 sized heaters.

On August 9, 2016, following discovery that the incorrect heaters had been installed, the licensee initiated a condition report, assessed the operability impacts, and took action to perform thermography and motor current measurements to verify pump operational status. The licensee found that thermography results were normal, and the motor amperage was measured to be within its expected range. The licensee subsequently took action to scope replacement of the heaters into the next pump out of service window, which was scheduled for August 10, 2016. On August 10, 2016, the inspectors re-engaged the licensee and questioned what had caused the pump to trip on August 6, 2016, if the heater size had not been the cause. Following additional questions, the licensee initiated a failure modes and effects analysis (FMEA). The FMEA concluded that the likely cause of the pump trip was a failure associated with the TO relay. Based on this conclusion, the licensee added replacement of this component to the REC pump B out of service work window. The work was originally scheduled to last for several hours, but due to the need to correct the issues associated with REC pump B, the out of service time was extended by approximately 2 days. Following repairs, the pump was restored to operable status midday on August 11, 2016.

Analysis. The inspectors determined that the licensee's failure to correctly translate the design basis into work instructions for TO relay heaters associated with REC pump B was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the design control attribute of the Mitigating Systems Cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency resulted in a challenge to operability, a 2-day extension of pump out of service time, and an initial failure to pursue identification of the actual cause of the August 6, 2016, REC pump B trip. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, the inspectors determined that the finding had very low safety significance (Green) because: it was not a design deficiency; did not represent a loss of system and/or function; did not represent an actual loss of function of at least a single train for longer than its technical specification allowed outage time; and did not result in the loss of a high safety-significant non-technical specification train. The finding had a cross-cutting aspect in the area of problem identification and resolution associated with evaluation. Specifically, the licensee failed to thoroughly evaluate the REC pump issues to ensure that the resolution addressed the cause and extent of condition commensurate with the safety significance [P.2].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. Design changes shall be subject to design control measures commensurate with those applied to the original design. Contrary to the above, between August 7 and August 9, 2016, the licensee failed to assure that applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions, and that design changes were subject to design control measures commensurate with those applied to the original design. Specifically, on August 7, 2016, during corrective maintenance for an REC pump B trip, the licensee developed instructions that directed installation of incorrectly sized TO heaters, introducing a condition that was nonconforming with the design basis. The performance deficiency resulted in a challenge to operability, a 2-day extension of pump out of service time, and an initial failure to pursue identification of the actual cause of the August 6, 2016, REC pump B trip. Immediate corrective actions included replacing the incorrectly sized heaters, performing a failure modes analysis to determine the actual cause of the REC pump B trip, and replacing the TO relay. Because this violation was of very low safety significance (Green) and was entered into the licensee's corrective action program as Condition Report CR-CNS-2016-04649, this violation is being treated as a non-cited violation in accordance with Section 2.3.2.a of the NRC Enforcement Policy. (NCV 05000298/2016003-01, "Failure to Maintain Design Control for Reactor Equipment Cooling Pump B")

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

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

- July 15, 2016, Functionality assessment of the failure of FP-TD-19-2 and maintaining the reactor building sump valves open
- July 27, 2016, Operability determination of the residual heat removal pump D discharge check valve RHR-CV-17CV leakage
- August 12, 2016, Operability determination of inadequate control room envelope boundary penetration cure time
- September 23, 2016, Operability determination of the residual heat removal B minimum flow valve failure to close
- September 30, 2016, Operability determination of a pin hole leak in service water piping for reactor equipment cooling heat exchanger B

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

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

b. Findings

Introduction. The inspectors identified a Green, non-cited violation of Technical Specification (TS) 3.5.1, "Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling System," for the licensee's failure to evaluate and implement adequate internal flooding protection compensatory measures to maintain low pressure coolant injection/spray systems operable. Specifically, from July 11, 2016, to July 15, 2016, the licensee placed the torus area and reactor building floor drain valve switches in the open position, defeating the automatic flood protection function credited in the licensee's internal flooding analysis, and failed to implement adequate compensatory measures. This resulted in inoperability of both the Division I core spray and Division I residual heat removal (RHR) systems for a period greater than allowed by the plant's technical specifications.

Description. On July 11, 2016, the licensee was performing Surveillance Procedure 6.FP.306, "Fire Detection Systems Examination," Revision 19, which tests the fire detectors in the reactor building and causes the torus and reactor building floor drains to automatically close. During performance of this procedure, the reactor building southeast (SE) quad thermal detector FP-TD-19-2 failed to reset, preventing the torus and reactor building floor drains from re-opening. The licensee took the following actions in response to the FP-TD-19-2 reset failure: (1) declared the associated fire detection system inoperable and established a required 2-hour fire watch patrol in the affected areas; and (2) took actions directed by Station Procedure 2.3_FP-1, “Fire Protection – Annunciator 1,” Revision 12. Station Procedure 2.3_FP-1 states, “if a fire was not detected and the detector cannot be reset, then perform one of the following actions: (1) place torus and floor drain valve switches from automatic to open; or (2) periodically monitor sump levels.” The licensee decided to place the torus and floor drain valve switches from the automatic to the open position. This caused the torus and floor drain valves to open and would have prevented them from automatically closing on a high-high sump alarm in response to a design basis flooding event from the high energy line break (HELB) of the 18-inch feedwater line. The licensee also initiated Work Order (WO) 5140550 to repair FP-TD-19-2, which was completed on July 15, 2016, and the torus and reactor building floor drain valve switches were restored to the automatic position. This issue was entered into the licensee’s corrective action program as Condition Report CR-CNS-2016-03963.

The licensee documented its operability evaluation in CR-CNS-2015-03963. The operability evaluation documented in CR-CNS-2016-03963 stated the following:

> “This condition directs any in-leakage into the sumps to be re-directed to the torus area. Per Station Evaluation NEDC 09-102, “Internal Flooding – HELB, MELB (moderate energy line break), and Feedwater Line Break,” Revision 1, in the event of an 18-inch feedwater line break in the steam tunnel the northeast (NE), northwest (NW), and southeast (SE) quad water levels may exceed allowable levels. However, sufficient systems in the southwest (SW) quad, high pressure coolant injection (HPCI) and Division II RHR, remain available for the station to reach safe shutdown conditions thus the flooding analysis remains functional for this condition.”

The inspectors reviewed the operability evaluation documented in CR-CNS-2016-03963 and the plant impact statement in WO 5140550. From this review, the inspectors questioned whether the licensee was in conformance with the current licensing basis for the HELB from the 18-inch feedwater line and whether a compensatory measure was required. The inspectors noted that defeating these credited flood barriers would allow cross-communication of internal flood waters between all four of the reactor building quads that house ECCS equipment. In response to the inspectors’ questions, the licensee stated there was not a nonconforming condition and no compensatory measures were required as discussed in CR-CNS-2016-03963 and WO 5140550. The licensee also stated that because the plant could still safely shut down during internal flooding events, no equipment should be rendered inoperable by this configuration.

In order to assess whether these valves were credited to protect the safety-related ECCS equipment during internal flooding events, or pipe breaks outside containment, the inspectors reviewed the TS and the supporting basis document; the USAR; the original safety evaluation report (SER); the Atomic Energy Commission (AEC) A. Giambuso letter dated December 18, 1972; Calculation NEDC 09-102, “Internal Flooding – HELB, MELB, and Feedwater Line Break;” and Station Procedure 0-Barrier, “Barrier Control Program.” The inspectors identified the following: TS Basis Document 3.5.1, “ECCS and RCIC System,” Applicable Safety Analyses stated, “The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The accidents for which ECCS operation is required are presented in References 5 and 6." The inspectors noted that Reference 5 was USAR, Section XIV-6, Reference 6 was USAR, Appendix G.

USAR, Appendix G, Section 2.4.2, states, in part, "Safety-related SSCs and parts shall be determined using the following methodology:

a. The safety-related functions that are required to prevent or mitigate accidents whose consequences could be comparable to the guideline exposures of 10 CFR Part 100 or 10 CFR 50.67 shall be determined. These accidents are the LOCA (pipe break inside containment), Pipe Break Outside Containment Accident, Control Rod Drop Accident, and Fuel-Handling Accident. (see USAR, Section XIV.) The dose limits of 10 CFR Part 100 are applied to the Control Rod Drop Accident and the Pipe Break Outside Containment Accident."

Using this information, the inspectors determined that the safety-related ECCS equipment would be relied upon to mitigate the consequences of pipe breaks outside containment, which could cause internal flooding hazards. This provided supporting evidence toward the inspectors' conclusion that the licensee needed to protect the ECCS equipment against those internal flooding hazards to maintain the equipment operable.

In addition, the inspectors reviewed the AEC A. Giambuso licensing basis letter for Cooper dated December 18, 1972, which described the creation of a General Design Criterion associated with protection of equipment important to safety from internal flooding hazards caused by pipe breaks outside containment. This letter directs protection of this equipment, and states, in part, the following:

"The Regulatory staff's continuing review of reactor power plant safety indicates that the consequences of postulated pipe failures outside of the containment structure, including the rupture of a main steam or feed-water line, need to be adequately documented and analyzed by licensees and applicants, and evaluated by the staff as soon as possible. Criterion No. 4 of the Commission's General Design Criteria, listed in Appendix A of 10 CFR Part 50 requires that:

> 'Structures, systems, and components, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power plant,'

USAR, Section IV-12.1 provides a documented evaluation in response to the AEC letter, stating, "An evaluation has been performed to substantiate that the design of Cooper Nuclear Station (CNS) is adequate to withstand the effects of a postulated rupture or break in any high energy fluid piping system outside the primary containment, including the double-ended rupture of the largest line in the main steam and feedwater system.

This study or evaluation, which captured the Cooper Nuclear Station HELB analyses, is contained in Amendments 20 and 25 to the Final Safety Analysis Report."

USAR Section IV-12.1 continues, "In summary, these analyses and evaluations performed by Cooper Nuclear Station that covered the specific criteria set forth by the NRC included the areas of pressure buildup resulting from pipe break, pipe whip impact on building elements, structural effects on building elements resulting from pressure down to the subsystem level, flooding of safety-related equipment, propagation of steam flow to the control room, and the control room habitability of operators as a result of a postulated pipe break failure. The HELB study also included specific remedial actions and emergency plans for handling a pipe break outside of containment that were automatic, required operator actions, and/or followed specific site procedures."

Final Safety Analysis Report, Amendment 25, discusses the CNS internal flooding analysis in detail. Specifically, this amendment discussed the credited automatic flood protection function of the floor drain valves in question. This Amendment concludes:

a. If a high energy line fails or causes a break below grade level, e.g. the torus area, adequate flooding protection for the corner compartments is provided. A description of the flooding protection for the ECCS compartments has been given in FSAR, Question 6.3, Amendment 9 (referenced in USAR Section X-14.6.2). FSAR, Question 6.3, states in part, if the break occurs as postulated in liquid or steam lines between the torus and the ECCS compartments, water or condensed steam will flow into the torus area. This water drains to sumps located in the NE, NW, and SE compartments. Air operated valves, installed in the drain lines in each of the three sumps, will shut automatically on sump high-high level and confine the water to the torus area.

b. If the feedwater line should break, and water reaches the reactor building grade level floor, through the north door of the steam tunnel, it would flow through floor drains to the basement compartment sumps. Air operated valves, installed in the drain lines to the compartment sumps, will shut automatically on sump high level, and will direct the water to the torus area, protecting the ECCS pumps.

The inspectors reviewed USAR, Section X-14.6.2.1 and Calculation NEDC 09-102 to determine which equipment was already analyzed to be lost during the worst case flooding events, and which additional equipment could be lost due to high flood levels if not protected by the drain valves in question. The inspectors determined that both of these references state, "A break of the 18-inch feedwater line within the steam tunnel was the bounding break that would affect all four reactor building quads and presents the largest challenge to the plant. The maximum postulated flood height (MPFH) following a feedwater line break was determined by the internal flooding calculation NEDC 09-102. The only MPFH that exceeds an allowable flood level from the 18-inch feedwater line break in the steam tunnel was the reactor building SE quad. This was due to a reactor building elevation 903 feet floor penetration which leads to the SE quad, equipment drain lines that do not isolate on a high-high sump level, and the procedurally open torus area drain line isolation valve. An assumed single failure of the reactor building floor drain isolation valves or the torus drain line isolation valves to close on a high-high sump level allows propagation in the NW and NE quad to exceed the level of environmentally qualified component (MHEQ). The technical specification related equipment contained in these quads are as follows: NE quad: Division I core spray and reactor core isolation cooling (RCIC); NW quad: Division I RHR; SE quad: Division II core spray; high pressure coolant injection (HPCI) 125 Vdc starter rack; SW quad: Division II RHR and HPCI."

The inspectors reviewed all pertinent design and licensing basis information and did not identify any operator action credited in the USAR or Calculation NEDC 09-102 to close the torus area or reactor building drain line isolation valves if the automatic isolation function failed on a high-high sump level. Additionally, Station Procedure 0-Barrier identified the torus and reactor building drain line isolation valves as credited flood protection components, with the exception of the SE quad torus drain isolation valve. The inspectors noted that Station Procedure 0-Barrier had pre-established compensatory measures listed in the procedure that had been evaluated per 10 CFR 50.59, but did not contain any pre-established compensatory measure for a manual operator action to close the torus and reactor building floor drain isolation valves. The inspectors also noted that in this configuration, without manual action, water would be introduced into all four quads during worst case flooding events. The inspectors determined that flood levels would not likely reach a high enough level to impact the Division II equipment in the SW quad. However, the inspectors noted that due to the design of the SE quad, the equipment contained in that quad, namely the Division II core spray pump, was already assumed and evaluated as lost during the 18-inch feedwater flooding event. This meant that as a result of the performance deficiency, both Division I and II core spray and Division I RHR would be lost during the worst case flooding scenario.

The inspectors concluded, from the information above, that the torus area and reactor building floor drain isolation valves had a design basis function to automatically close on high-high sump level to protect the safety-related equipment contained in the reactor building quads. The inspectors determined that the licensee had assessed functionality based on the worst case event occurring due to internal flooding from an 18-inch feedwater line HELB. This functionality assessment focused on whether the final conclusions of their worst case internal flooding calculation were still valid, i.e. that the plant could be safely shut down with one remaining division of RHR. The licensee did not recognize that the torus and floor drain valve automatic flood protection functions were support functions for Division I core spray and RHR during internal flooding scenarios, thus requiring a functionality assessment for each valve and an operability assessment for the supported safety-related SSCs. The inspectors concluded that with the drain valves' automatic flood protection capabilities non-functional, the configuration was nonconforming with the current licensing basis, and the supported Division I core spray and Division I RHR were inoperable without an adequate compensatory measure. The inspectors determined that this conclusion was consistent with NRC Inspection Manual Chapter 0326 guidance for applying the General Design Criteria to operability considerations, and Regulatory Issues Summary 01-009, "Control of Hazard Barriers." The inspectors informed the licensee of this deficiency. The licensee entered this deficiency into their corrective action program for resolution as Condition Report CR-CNS-2016-06056.

The inspectors reviewed Station Procedure 2.3_FP-1, which allowed defeating these flood barriers, for insights into the cause of this finding. The inspectors identified that the supporting 10 CFR 50.59 evaluation for the procedure did not recognize that placing torus and floor drain valve switches from the automatic to the open position was a nonconforming condition with the current licensing and design basis for internal flooding in the reactor building. The 50.59 evaluation conclusion stated: “The design basis for the reactor building sump inlet valves is to prevent excessive flooding of the quads which contain safety-related equipment. However, this is a “Good Practice” engineering design basis. For accident conditions, including pipe breaks and fires, which could cause flooding, no credit is taken for operation of these valves. Thus the proposed changes to the procedure do not affect the safety design basis for Cooper Nuclear Station.”

The inspectors determined that the procedural direction to defeat the automatic function of the drain valves without appropriate compensatory measures in place was contrary to the licensing and design basis. The resulting configuration was not consistent with the USAR, Section X-14.6.2.1, which states, “An assumed single failure of the reactor building floor drain isolation valves or the torus drain line isolation valves to close on a high-high sump level allows propagation in the NW and NE quad to exceed the level of EQ component (MHEQ).” As a result, the inspectors concluded that Station Procedure 2.3_FP-1 was inadequate, and led to the failure of operations personnel to recognize the need to assess operability and evaluate/implement a compensatory measure for the configuration.

<u>Analysis</u>. The licensee’s failure to maintain ECCS low pressure injection/spray systems operable for internal flooding hazards, in violation of Technical Specification 3.5.1, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the human performance attribute of the Mitigating Systems Cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, without automatic flood barrier protection or an associated compensatory measure, Division I core spray and Division I RHR systems were inoperable for a high-energy line break from the 18-inch feedwater line. Using Inspection Manual Chapter 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” dated June 19, 2012, the inspectors determined that the finding required a detailed risk evaluation because it involved two separate safety systems being out-of-service for greater than their technical specification allowed outage time.

A senior reactor analyst performed a detailed risk evaluation for this finding. In this evaluation the analyst assumed:

- The only flooding source which could produce sufficient flooding to flood all of the affected rooms was from the feedwater system. Flooding from smaller piping systems was assumed to allow expansive time for diagnosis and recovery and these sources of flooding were screened out. Based on this assumption, the analyst limited the group of initiating events analyzed to losses of main feedwater.

- The analyst assumed operations personnel would isolate feed upon diagnosing a leak of sufficient size to cause the flooding to occur and the feed and condensate systems were unavailable for event mitigation.

- No credit was given for the potential for operators to close the drain valves and separate the quads after the flooding had started.

- The exposure time of the cross-connected drains was 4 days.

- One hundred feet of feedwater piping was assumed to be in the room that was available to leak to cause the flooding. The analyst used piping leak data from the industry average parameter estimates derived for NUREG 6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," to estimate the leak frequency and assumed that both small and large leaks could cause the flooding.

- All quads were cross-connected such that the assumed flooding would allow water in all four of these quadrants, however the southwest quad would not have water sufficiently high enough to affect equipment in that quad. Flooding of the northeast, northwest, and southeast quads was assumed to render the following systems unavailable:
  - Division I core spray system
  - Division II core spray system
  - Reactor Core isolation cooling system
  - High pressure coolant injection system
  - Division I residual heat removal system

- No recovery credit was given for the equipment lost during the flooding.

The analyst applied these assumptions in the Cooper SPAR model, Version 8.22, run on SAPHIRE, Revision 8.1.4, to obtain a conditional core damage probability for losses of main feedwater with the equipment affected by the postulated flooding. The analyst then combined conditional core damage probability with the initiating event frequency of a feedwater leak which would cause the flooding over the exposure time. This yielded an estimate of the increase in core damage frequency of 2.7E-8/year, which made the finding of very low safety significance (Green). The dominant sequences were flooding-induced losses of main feedwater. Remaining mitigating equipment were the Division II residual heat removal system and the automatic depressurization system, which would upon initiation allow injection from low pressure sources. The analyst used NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," dated May 6, 2004, to determine that since the total increase in core damage frequency of the finding was less than 1.0E-7/year, the increase in large early release frequency was of very low safety significance (Green).

The finding had a cross-cutting aspect in the area of human performance associated with documentation because the licensee failed to create and maintain complete, accurate, and up-to-date documentation. Specifically, Station Procedure 2.3_FP-1 contained inappropriate directions to defeat the flood barriers because it did not recognize the credited automatic flood protection function provided by the valves; thus, operations personnel failed to recognize the need for compensatory measures [H.7].

Enforcement. Technical Specification 3.5.1, "Emergency Core Cooling Systems and Reactor Core Isolation Cooling System," requires, in part, that each ECCS injection/spray subsystem shall be operable in Modes 1, 2, and 3. Technical Specification 3.5.1, Condition H, requires that if two or more low pressure ECCS injection/spray subsystems are inoperable for reasons other than Condition A, then

immediately enter Limiting Condition for Operation (LCO) 3.0.3. LCO 3.0.3 states, in part, when an LCO is not met and the associated actions are not met, actions shall be initiated within 1 hour to place the unit, as applicable, in Mode 2 within 7 hours; Mode 3 within 13 hours; and Mode 4 within 37 hours. Contrary to the above, from July 11 to July 15, 2016, with two Division I ECCS low pressure coolant injection/spray systems inoperable, actions were not initiated within 1 hour to place the unit, as applicable, in Mode 2 within 7 hours; Mode 3 within 13 hours; and Mode 4 within 37 hours. Without automatic flood barrier protection or an associated compensatory measure, Division I core spray and Division I RHR systems were inoperable for a high-energy line break from the 18-inch feedwater line. As immediate corrective actions, the licensee repaired the fire detection equipment; restored the torus and reactor building floor drain automatic flood protection functions; and initiated a condition report to evaluate the technical specification impacts. Because this violation was of very low safety significance (Green) and was entered into the licensee's corrective action program as Condition Report CR-CNS-2016-06056, this violation is being treated as a non-cited violation in accordance with Section 2.3.2.a of the NRC Enforcement Policy.
(NCV 05000298/2016003-02, "Failure to Maintain Low Pressure Injection/Spray Operable From Internal Flooding Hazards")

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed two permanent plant modifications that affected risk-significant structures, systems, and components (SSCs):

- July 14, 2016, Residual heat removal shutdown cooling high pressure isolation instrument location change and jumper installation

- September 8, 2016, Spent fuel pool bridge settings not in accordance with the Updated Safety Analysis Report

The inspectors reviewed the design and implementation of the modifications. The inspectors verified that work activities involved in implementing the modifications did not adversely impact operator actions that may be required in response to an emergency or other unplanned event. The inspectors verified that post-modification testing was adequate to establish the operability and functionality of the SSCs as modified.

These activities constituted completion of two samples of permanent modifications, as defined in Inspection Procedure 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed four post-maintenance testing activities that affected risk-significant structures, systems, or components (SSCs):

- July 18, 2016, H2O2 maintenance, Division 1
- July 19, 2016, Service water booster pumps A and C
- August 19, 2016, Residual heat removal minimum flow isolation logic relay replacement
- August 12, 2016, Reactor equipment cooling pump B thermal overload relay and heater 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 constituted completion of four post-maintenance testing inspection samples, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

During the station’s refueling outage that began on September 24, 2016, the inspectors evaluated the licensee’s outage activities. The inspectors verified that the licensee considered risk in developing and implementing the outage plan, appropriately managed personnel fatigue, and developed mitigation strategies for losses of key safety functions. This verification included the following:

- Review of the licensee’s outage plan prior to the outage
- Monitoring of shut-down and cool-down activities
- Verification that the licensee maintained defense-in-depth during outage activities
- Observation and review of reduced-inventory activities
- Review of operations with the potential to drain the reactor vessel (OPDRVs)

The refueling outage continued through the end of the inspection period.

These activities constituted partial completion of one refueling outage sample, as defined in Inspection Procedure 71111.20.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed four risk-significant surveillance tests and reviewed test results to verify that these tests adequately demonstrated that the structures, systems, and components (SSCs) were capable of performing their safety functions:

In-service tests:

- July 27, 2016, Residual heat removal pump quarterly in service test, Division II

Containment isolation valve surveillance tests:

- September 30, 2016, Main steam isolation valve local leak-rate test

Other surveillance tests:

- August 2, 2016, Reactor equipment cooling motor operated valve operability test
- August 3, 2016, South scram discharge volume high water level channel calibration, Division 1

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 constituted completion of four surveillance testing inspection samples, as defined in Inspection Procedure 71111.22.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

Training Evolution Observation

a. Inspection Scope

On August 2, 2016, the inspectors observed simulator-based licensed operator requalification training that included implementation of the licensee’s emergency plan. The inspectors verified that the licensee’s emergency classifications, off-site notifications, and protective action recommendations were appropriate and timely. The inspectors verified that any emergency preparedness weaknesses were appropriately identified by the evaluators and entered into the corrective action program for resolution.

These activities constituted completion of one training observation sample, as defined in Inspection Procedure 71114.06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

Unplanned Scrams with Complications (IE04)

a. Inspection Scope

The inspectors reviewed the licensee’s basis for including or excluding in this performance indicator each scram that occurred between July 1, 2015, and June 30, 2016. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, to determine the accuracy of the data reported.

These activities constituted verification of the unplanned scrams with complications performance indicator, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review

a. Inspection Scope

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. Findings

No findings were identified.

.2 Annual Follow-up of Selected Issues

a. Inspection Scope

The inspectors selected four issues for an in-depth follow-up:

- On August 22, 2016, review of Calculation NEDC-16-003 associated with turbine building blowout panels

  On May 8, 2015, the inspectors identified a concern regarding the technical adequacy of Calculation NEDC-13-028, "Ultimate Internal Pressure of Turbine Building Blowout Panels and Metal Wall System." Specifically, the inspectors noted that the calculation included a number of nonconservative assumptions and that the finite-element analysis modeling of the turbine building siding incorporated in Calculation NEDC-13-028 did not appear to accurately reflect the interior structure of the turbine building blow-out panels. In response to this issue, the licensee initiated actions to develop a new Calculation No.16-003, Revision 0, "Structural Evaluation of the Turbine Building Blowout Panels Steel Supports." Based on the complexity of this refined calculation, which evaluated the dynamic effects of a postulated high energy line break in the turbine building, the inspectors requested assistance from the NRC Office of Nuclear Regulatory Research (NRR) Research/Design Engineering Branch to confirm the adequacy of this design basis document.

  Predicated on the detailed review of Calculation No.16-003, Research/Design Engineering Branch concluded that, although the staff had several qualifying comments, the calculation adequately established the range of failure of the connecting welds at high energy line break pressures below 0.5 pounds per square inch specified in Cooper Nuclear Station's Updated Final Safety Analysis Report. Specifically, as stated in Calculation No.16-003, Section 5.0, the failure of the connection welds at pressures of approximately 0.38 to 0.425 pounds per square inch leads to blowout of the siding panels without the failure of the attachment bolts. Therefore, based on the staff's independent finite element analysis of the turbine building blow-out panels, the staff confirmed that Calculation No.16-003, Revision 0, adequately established the range of failure of the connecting welds at high energy line break pressures below 0.5 pounds per square inch.

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the identified condition.

- On July 28, 2016, spare reactor recirculation instrument primary containment isolation valves for penetrations X-31C and X-31D testing requirements

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

- On September 9, 2016, service water pump B enclosing tube failure

  The inspectors assessed the licensee's problem identification threshold, cause analyses, and extent of condition reviews. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

- On September 26, 2016, a select sample of root cause evaluations, focused on extent of condition and extent of cause evaluation adequacy

  The inspectors assessed the licensee's problem identification threshold, cause analyses, and extent of condition reviews. The inspectors discovered that the licensee's extent of condition and extent of cause for a root cause evaluation associated with two high pressure coolant injection failures was narrowly focused. The inspectors observed that the resulting evaluation lacked thoroughness and did not adequately address the extent of cause and condition of the equipment issues. The inspectors provided their observations to the licensee, and the licensee took action to reopen the affected root cause evaluation and perform new, more detailed extent of cause and condition evaluations. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

These activities constituted completion of four annual follow-up samples, as defined in Inspection Procedure 71152.

b. Findings

Introduction. The inspectors reviewed a self-revealed, Green, non-cited violation of Technical Specification 5.4.1.a for the licensee's failure to maintain a procedure required by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, the licensee failed to maintain Station Procedure 7.2.15, "Service Water Pump Column Maintenance and Bowl Assembly Replacement," Revision 37, in accordance with the documented vendor manual service water pump shaft tolerances.

Description. On April 22, 2016, service water pump B (SW-P-B) was placed into service to perform required on-demand quarterly surveillance testing. Licensee personnel noted a step change in SW-P-B gland water flow and declared the pump inoperable. During troubleshooting activities, the licensee determined there was indication of a separation of the enclosing tube. On April 27, 2016, SW-P-B was disassembled in accordance with Station Procedure 7.2.15, "Service Water Pump Column Maintenance and Bowl Assembly Replacement," Revision 37. During disassembly of SW-P-B, the enclosing tube was found broken in the thread relief area immediately above the jump bearing area. Additionally, the licensee identified abnormal wear patterns on the pump shaft at the bearing locations. The licensee repaired SW-P-B and returned it to service on May 1, 2016. The licensee entered this deficiency into the corrective action program as Condition Report CR-CNS-2016-02342, and the licensee initiated an apparent cause evaluation to investigate the condition.

The apparent cause evaluation concluded the failure of SW-P-B's enclosing tube was a result of a bending mode being introduced from a combination of pump shaft total indicated runouts and column register fits at the upper limit of acceptable levels in accordance with Station Procedure 7.2.15. This resulted in an unbalanced condition for SW-P-B at running speed and a geometry that caused the failure of the enclosing tube and abnormal bearing wear patterns. This condition required the licensee to enter an unplanned limiting condition for operation (LCO) to repair the damage to ensure the availability, reliability, and capability of a system that responds to initiating events to prevent undesirable consequences. The licensee determined that in 1997, Station Procedure 7.2.15 was changed to allow for relaxed service water pump refurbishment tolerances based on a recorded phone conversation with the vendor, and a vendor provided shaft straightening procedure. Specifically, Attachment 1, Step 5.5.3, states that, "during pump shaft tolerance measurements, Notes 1 and 2 may be referred to prior to Step 5.5.3 in Section 5." Notes 1 and 2 stated maximum acceptable tolerance as 0.007 inches. These refurbishment tolerances were in excess of the documented vendor manual criteria of 0.005 inches for conducting maintenance on service water pumps. A contributing cause was associated with a reduction of wall thickness in the thread relief area which resulted in corrosion pitting, which was initiated by wrench marks during assembly. Station Procedure 7.2.15 did not include any limitations to alert maintenance personnel that pipe wrench marks in this area would result in corrosion pitting. The inspectors determined that this issue was self-revealing because it was identified as a result of on-demand surveillance testing, causing the licensee to declare SW-P-B inoperable and enter an unplanned LCO to conduct repairs.

<u>Analysis</u>. The licensee's failure to maintain Station Procedure 7.2.15 in accordance with documented vendor manual service water pump shaft tolerances, in violation of Technical Specification 5.4.1.a, was a performance deficiency. The performance deficiency was determined to be more than minor, and therefore a finding, because it was associated with the procedural quality attribute of the Mitigating Systems Cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure of the enclosing tube caused a step change in gland water flow and required the licensee to enter an unplanned LCO to conduct repairs. Using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, inspectors determined the finding screened as having very low significance (Green) because: it was not a design deficiency; did not represent a loss of system and/or function; did not represent an actual loss of function of at least a single train for longer than its technical specification allowed outage time; and did not result in the loss of a high safety-significant non-technical specification train. A cross-cutting aspect was not assigned to this finding because the performance deficiency occurred in 1997 and, therefore, was not indicative of current licensee performance.

<u>Enforcement</u>. Technical Specification 5.4.1.a requires, in part, that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Appendix A to Regulatory Guide 1.33, "Quality Assurance Program Requirements," Revision 2, February 1978. Regulatory Guide 1.33, Section 9.a requires procedures for performing maintenance that can affect the performance of safety-related equipment. Contrary to the above, from 1997 until present, the licensee failed to maintain a procedure for performing service water pump maintenance that can affect the performance of safety-related equipment. Specifically, Station Procedure 7.2.15, "Service Water Pump Column Maintenance and Bowl Assembly Replacement," Revision 37, was not maintained in accordance with documented vendor manual service

water pump shaft tolerances of 0.005 inches. Station Procedure 7.2.15, Attachment 1, Step 5.5.3 stated that during pump shaft tolerance measurements, maximum acceptable tolerances were 0.007 inches, which exceeded the vendor manual tolerances of 0.005 inches. This resulted in a failure of the enclosing tube causing a step change in gland water flow and required the licensee to enter an unplanned LCO to conduct repairs. As an immediate corrective action, the licensee evaluated the cause of the failure and conducted repairs to the pump. Because this violation was of very low safety significance (Green) and was entered into the licensee's corrective action program as Condition Report CR-CNS-2016-02342, this violation is being treated as a non-cited violation in accordance with Section 2.3.2.a of the NRC Enforcement Policy. (NCV 05000298/2016003-03, "Failure to Maintain Service Water Pump Maintenance Procedure")

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

.1 Abnormal Procedure Entry for a False Fire Protection Alarm

a. Inspection Scope

On August 30, 2016, at 10:27 am, the inspectors responded to the control room in response to a plant wide announcement for a fire in the main power transformer (MPT) B due to the operators receiving fire protection annunciator MPT B, system 16 trip. This alarm provides indication of the activation of the deluge system for MPT B. The control room operators took action per Station Procedure 2.3_FP-3, "Fire Protection – Annunciator 3," Revision 13, and immediately entered Emergency Procedure 5.1Incident, "Site Emergency Incident," Revision 35. The control room dispatched operations personnel to the turbine building, elevation 882 south (T-882 south), and the fire brigade to the MPT yard. The MPT yard was locally inspected with a thermal imager by the fire brigade to verify if there was a fire or abnormal heat signatures present. Additionally, control room indications showed no actuation of the fire protection pumps or changes in MPT B temperatures. At 10:34 am, the incident commander confirmed no fire existed in the MPT B. The operations personnel dispatched to T-882 south reported no actuation of the deluge valve for fire protection system 16. The work control center informed the control room about a report from maintenance personnel that fire protection system 16 alarm test valve, FP-V-416, was bumped during maintenance of nearby equipment. Test valve FP-V-416 was found approximately 1/8th open, and operations personnel restored test valve FP-V-416 to its normal configuration of closed. The station exited Emergency Procedure 5.1Incident at 10:44 am. The inspectors toured the control room during the event to verify stable plant conditions, reviewed station logs, discussed the event with the operations and maintenance staff, and reviewed NUREG-1022, "Event Reporting Guidelines," Revision 3, to ensure licensee compliance.

b. Findings

No findings were identified.

.2 Notification of Unusual Event Declared Due to an Earthquake

a. Inspection Scope

At 7:04 am on September 3, 2016, Cooper Nuclear Station (CNS) experienced a seismic event as indicated by their SEISMIC EVENT control room annunciator coming into alarm, and the control room staff feeling the motion of an earthquake. This annunciator alarms after detecting 0.01g or more ground motion on the seismic monitors. The station entered their Emergency Procedure 5.1Earthquake, and entered an Emergency Action Level (EAL) in response to the seismic event. At 7:10 am, the site declared a Notification of Unusual Event (NOUE), consistent with EAL HU1.1, due to a seismic event based on the alarm and earthquake motion felt in the plant control room. The resident inspectors were informed at 7:18 am, and responded to the site.

At the time the earthquake was felt, the control room also received an alarm for emergency condensate storage tank (ECST) high level, which came in and cleared twice, concurrent with the earthquake. This safety-related tank supplies water to high pressure coolant injection pumps. The licensee determined that the alarms were attributable to sloshing of the water in the tank due to the seismic motion. The licensee also detected very slight fluctuations in turbine vibrations, grid reactive loading, and torus level; but there was ultimately no impact to the plant. As a result of the minimal site impacts, the licensee chose not to staff their Emergency Response Facilities. Operations personnel performed walk-downs of important plant equipment in the time immediately following the earthquake. In addition, operations personnel walked down several plant steam/water leaks the site was already monitoring to determine if the seismic event had exacerbated any leakage. These walk-downs did not identify any negative impacts to plant equipment or any increase in existing leakage.

Following initial response, engineering personnel performed more detailed walk-downs of additional equipment to look for structural impacts. Based on discussions with the U.S. Geological Survey, the licensee determined that the area was generally at risk for aftershocks for approximately 2 to 3 hours following the seismic event. As a result, the site remained in the NOUE for several hours until the risk of aftershocks had subsided and engineering personnel had completed their walk-downs. The site exited the NOUE at 3:47 pm on September 3, 2016.

Upon notification of the event, the resident inspectors responded to the site to assess plant conditions. The inspectors toured the control room during the event to verify stable plant conditions, and performed independent walk-downs of important plant areas to look for seismic damage. In addition, the inspectors reviewed station logs; discussed the event with the operations, maintenance, and emergency response staff; and reviewed NUREG-1022, “Event Reporting Guidelines,” Revision 3, to ensure licensee compliance.

b. Findings

No findings were identified.

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

4OA5 Other Activities

Temporary Instruction 2515/190 – Inspection of the Proposed Interim Actions Associated with Near-Term Task Force Recommendation 2.1 Flooding Hazard Evaluations

a. Inspection Scope

The inspectors independently verified that the licensee's proposed interim actions would perform their intended function for flooding mitigation.

- Visual inspection of flood protection equipment was performed.
- Reasonable simulation performed by the licensee was independently reviewed by the inspectors.
- Flood protection feature functionality was determined by review of design documentation and in-plant walk-downs of the planned installation strategy.

The inspectors verified that issues identified were entered into the licensee's corrective action program.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On September 1, 2016, the inspectors presented the results of the Temporary Instruction 2515/190 inspection to Mr. Oscar Limpias, Vice President-Nuclear and Chief Nuclear Officer, and other members of the licensee's staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

On September 30, 2016, the inspectors presented the inspection results to Mr. Oscar Limpias, Vice President-Nuclear and Chief Nuclear Officer, 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.

On October 12, 2016, the inspectors presented the inspection results to Mr. Ken Higginbotham, General Manager Plant Operations, 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

T. Barker, Manager, Engineering Program and Components
D. Buman, Director, Engineering
B. Chapin, Manager, Maintenance
S. Charbonnet, Coordinator, Nondestructive Examination
T. Chard, Manager, Quality Assurance
L. Dewhirst, Manager, Corrective Action and Assessment
K. Dia, Manager, System Engineering
R. Estrada, Design Engineering Manager
J. Flaherty, Senior Licensing Engineer
T. Forland, Engineer, Licensing
D. Goodman, Manager, Operations
K. Higginbotham, General Manager Plant Operations
D. Kimball, Director, Nuclear Oversight
B. Kirkpatrick, Specialist, Licensing
P. Leininger, Engineer, Inservice Inspection Program
O. Limpias, Vice President-Nuclear and Chief Nuclear Officer
T. McClure, Engineer (Alternate), Inservice Inspection Program
R. Penfield, Director, Nuclear Safety Assurance
J. Shaw, Manager, Licensing
J. Smith, Welding Coordinator, Maintenance
J. Stough, Manager, Emergency Preparedness
C. Sunderman, Manager, Radiation Protection
K. Tom, Assistant to the Director, Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2016003-01	NCV	Failure to Maintain Design Control for Reactor Equipment Cooling Pump B (Section 1R13)
05000298/2016003-02	NCV	Failure to Maintain Low Pressure Injection/Spray Operable From Internal Flooding Hazards (Section 1R15)
05000298/2016003-03	NCV	Failure to Maintain Service Water Pump Maintenance Procedure (Section 4OA2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Miscellaneous Documents

Number	Title	Revision
	HVAC Load Calculation for Control Building EL 903’ 06”	9

Miscellaneous Documents

Number	Title	Revision
88-299A	NEDC, Review of S&L Calc. No. COOLC-01	6
93-054	NEDC, Control Room Heatup During 24 Hour Period	4

Procedures

Number	Title	Revision
2.1.4	Seasonal Weather Preparations	28
2.2.84	HVAC Main Control Room and Cable Spreading Room	53
2.2.84A	HVAC Main Control Room and Cable Spreading Room System Component Checklist	1
2.4HVAC	Building Ventilation Abnormal	23
5.1Weather	Operation During Weather Watches and Warnings	15
5.3Grid	Degraded Grid Voltage	45
EOP 5A	Secondary Containment Control	15

Condition Reports (CRs)

CR-CNS-2015-04006	CR-CNS-2015-04014	CR-CNS-2016-00007	CR-CNS-2016-00378
CR-CNS-2016-00379	CR-CNS-2016-00487	CR-CNS-2016-00831	CR-CNS-2016-01058
CR-CNS-2016-01166	CR-CNS-2016-02270	CR-CNS-2016-03876	CR-CNS-2016-03877
CR-CNS-2016-03878	CR-CNS-2016-03880	CR-CNS-2016-03882	CR-CNS-2016-03883
CR-CNS-2016-03884	CR-CNS-2016-03887	CR-CNS-2016-03888	CR-CNS-2016-03891
CR-CNS-2016-03892	CR-CNS-2016-03898	CR-CNS-2016-03899	CR-CNS-2016-03902
CR-CNS-2016-03903	CR-CNS-2016-03904	CR-CNS-2016-03911	CR-CNS-2016-03913
CR-CNS-2016-03916	CR-CNS-2016-05248		

Section 1R04: Equipment Alignment

Miscellaneous Documents

Number	Title	Revision
88-299A	HVAC Load Calculation for Control Building EL 903’ 06”	9
88-298	NEDC, Review of S&L Calc 8206-E1 Control Bldg Heat Loads	5, 5C1, 5C2, 5C3
90-039	NEDC. Review of Sargent & Lundy COOSP-01, 02, & 03 Temperature Switch Setpoint Calculation	3C2

Miscellaneous Documents

Number	Title	Revision
94-230	NEDC, Vessel Head-Over-Drywell Capacity Curve for Input into ECCS Analysis	5
2018	Burns and Roe, Flow Diagram Turbine Generator BLDG & Control BLDG Heating & Ventilation Cooper Nuclear Station	40
2040	Burns and Roe, Cooper Nuclear Station Flow Diagram Residual Heat Removal, Sheet 1	N82

Procedures

Number	Title	Revision
2.2.38	HVAC Control Building	42
2.2.69	Residual Heat Removal System	98
2.2.69.3	RHR Suppression Pool Cooling and Containment Spray	46
2.2A.RHR.DIV2	Residual Heat Removal System Component Checklist (DIV 2)	10
2.4SDC	Shutdown Cooling Abnormal	15
6.CSCS.601	Technical Specifications Verification of Flowpath Valve Lineup	20
6.RHR.202	RHR Crosstie Valve Position Monitor Functional Test (IST)	14
6.1HV.303	Division 1 Essential Control Building Ventilation Temperature Switch Change Out and Functional Test	16
6.2HV.303	Division 2 Essential Control Building Ventilation Temperature Switch Change Out and Functional Test	19

Section 1R05: Fire Protection

Miscellaneous Documents

Number	Title	Revision/Date
	LCOTR FP15-BLDG-DOOR-D126, Fire Door D126 Fire Impairment Log	July 21, 2016
0.7.1 Attachment	Transient Combustible Permit	January 20, 2016
09-095	NEDC, CNS Detailed Fire Modeling Report – Fire Compartment TB-A	3
11-019	NEDC, CNS NSCA Analysis	March 26, 2015
11-094	NEDC	3

Miscellaneous Documents

Number	Title	Revision/Date
11-100	NEDC, Fire Safety Analysis for Fire Area RB-M EPM Report R1906-008-RBM	3
11-105	NEDC, CNS Station Fire Safety Analysis – Fire Table TB-A	3
CNS-FP-231	Reactor Building Control Corridor Pre-Fire Plan	6
CNS-FP-243	Turbine Building Reactor Feed Pump Area Pre-Fire Plan	5
CNS-FP-244	Turbine Building Air Ejector and Vacuum Pump Area Pre-Fire Plan	5

Procedures

Number	Title	Revision
0.23	CNS Fire Protection Plan	74
0.7.1	Control of Combustibles	40
6.FP.604	Fire Door Full Examination	28

Section 1R06: Flood Protection Measures

Miscellaneous Documents

Number	Title	Date
15-14	Condition Monitoring Report, Control Building/Manhole C1	July 13, 2015
15-15	Condition Monitoring Report, Control Building/Manhole C2	July 13, 2015
15-16	Condition Monitoring Report, Control Building/Manhole P1	July 13, 2015
15-17	Condition Monitoring Report, Control Building/Manhole P2	July 13, 2015

Procedures

Number	Title	Revision
0.36.3	Confined Space Procedure	14
0.41	Seismic Housekeeping	11
0.44	Housekeeping Cleanliness Controls	24
0.54	Cable Reliability Program	3
3-EN-DC-150	Condition Monitoring of Maintenance Rule Structures	6C4
3.47.25	Non-EQ Inaccessible Power Cables Program	4

Work Orders

5013197	5034916	5061273

Section 1R08: Inservice Inspection Activities

Procedures

Number	Title	Revision
0-EN-IS-1 14	Fall Protection	11C0
7.7.1	Special Process Control Maintenance Procedure	15
7.7.3.1	General Welding Standard For ASME And ANSI Code Applications	4
7.7.5.1	Welding Material Care, Storage, And Control Procedure CNS-WFMC	7
7.7.10.2	P1-B Welding Procedure Specification	5
7.7.10.4	P1-G Welding Procedure Specification	5
7.7.10.6	P1-BG Welding Procedure Specification	4
7.7.10.80	P8-A Welding Procedure Specification	3
7.7.10.83	P1-P8A Welding Procedure Specification	3
QCP-9.1.0	Visual Examination - General Requirements	2
QCP-9.1.5	Visual Examination of Hangers, Supports, Restraints, and Components - VT3	3
QCP-9.1.6-CNS	Visual Examination of Class MC Metal Containment Components	1
QCP-9.4.0	UT Thickness Procedure	1
3.28.1.1	Visual VT-1 Examination of Pressure Retaining Bolting and Integral Attachments	13
3.28.1.6	Visual Examination of Containment Bolting, VT-1	10
7.2.34.1	Snubber Examination	32
7.2.34.2	Pipe Snubber Removal and Installation	32
7.2.57	ASME Category F-A Component Supports Examination and Adjustments	20
GEH-VT-103	Procedure for VT-3 Examination	10
GEH-VT-102	Procedure for VT-2 Examinations	4
GEH-VT-101	Procedure for VT-1 Examinations	7
GEH-VT-204	Procedure for Invessel Visual Inspection (IVVI) of BWR-4 RPV Internals	16

Procedures

Number	Title	Revision
O-CNS-LI-1 04	Self-Assessment and Benchmark Process	1

Condition Reports (CRs)

CR-CNS-2014-06299	CR-CNS-2014-06362	CR-CNS-2014-06363	CR-CNS-2014-06364
CR-CNS-2014-06366	CR-CNS-2014-06373	CR-CNS-2014-06569	CR-CNS-2014-06968
CR-CNS-2014-06969	CR-CNS-2014-06972	CR-CNS-2014-07026	CR-CNS-2014-07201
CR-CNS-2014-07204	CR-CNS-2014-07205	CR-CNS-2014-07207	CR-CNS-2014-07232
CR-CNS-2014-07369	CR-CNS-2014-07377	CR-CNS-2014-07435	CR-CNS-2014-07517
CR-CNS-2015-01225	CR-CNS-2015-01226	CR-CNS-2015-03447	CR-CNS-2015-04172
CR-CNS-2015-06714			

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

Miscellaneous Documents

Number	Title	Revision/Date
	Cooper Nuclear Station Drill and Exercise Manual, EP DEP Evaluation Process for Limited Scope Simulator Drills, Attachment H-3	10
RMP 29-025	Reactivity Maneuver Plan – Shutdown for RE29	September 14, 2016
SKL052-52-49	Simulator Exam Scenario 49	8

Procedures

Number	Title	Revision
0.50.5	Outage Shutdown Safety	35
2.1.4	Normal Shutdown	152
2.1.5	Reactor Scram	73
2.1.10	Station Power Changes	112
2.2.28	Feedwater System Startup and Shutdown	104
EPIP 5.7.1	Emergency Action Level Technical Bases, Attachment 2	54
EPIP 5.7.1	Cooper Nuclear Station Emergency Action Level Matrix, Attachment 4	13

Condition Reports (CRs)

CR-CNS-2016-05808	CR-CNS-2016-05809	CR-CNS-2016-05814	CR-CNS-2016-05817
CR-CNS-2016-05818	CR-CNS-2016-05819	CR-CNS-2016-05820	CR-CNS-2016-05831
CR-CNS-2016-05835			

Section 1R12: Maintenance Effectiveness

Miscellaneous Documents

Number	Title	Revision/Date
	Maintenance Rule Functional Failure Evaluations for the High Pressure Coolant Injection System	June 1, 2014 through August 1, 2016
791E272	Elementary Diagram – HPCI System, Sheet 10	N21
4033-55750-23	Nutherm Panel EE-STR-250-HPCI (ALOP) Schematic	N06
RCE 2016-02281	HPCI Declared Inoperable Twice in Two Days	0

Condition Reports (CRs)

CR-CNS-2013-02323	CR-CNS-2013-07245	CR-CNS-2015-07260	CR-CNS-2016-02318
CR-CNS-2016-02452	CR-CNS-2016-02589	CR-CNS-2016-02753	CR-CNS-2016-02881
CR-CNS-2016-02923	CR-CNS-2016-03958	CR-CNS-2016-03974	CR-CNS-2016-04079

Work Orders

5002448	5107287	5114655	5114656	5130230

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Miscellaneous Documents

Number	Title	Revision/Date
	Protected Equipment Program Electronic Tracking Form, Week 1633 Move RHR-MO-39B Conduit	0
	REC-P-B Trip Failure Modes and Effects Analysis	August 8, 2016
CO RHRB-1-5140092-39B	RHR-MO-39B Clearance Order	0
91-184	NEDC, Motor Overload Heater Sizing	5

Procedures

Number	Title	Revision
0-CNS-WM-104	On-line Schedule Risk Assessment	3
0-PROTECT-EQP	Protected Equipment Program	34
7.0.5	CNS Post-Maintenance Testing	52
7.3.20.3	Motor Analysis	18

Condition Reports (CRs)

CR-CNS-2012-05389	CR-CNS-2012-05401	CR-CNS-2012-05871	CR-CNS-2012-09088
CR-CNS-2016-04628	CR-CNS-2016-04629	CR-CNS-2016-04633	CR-CNS-2016-04682
CR-CNS-2016-04728			

Work Orders

4803258	5012016	5012118	5062728	5064991
5098018	5140092	5143658	5144374	

Section 1R15: Operability Determinations and Functionality Assessments

Miscellaneous Documents

Number	Title	Revision/Date
	CRE Floor Penetration Leak Test Timeline	May 25, 2016
BCP-2016-0004	Barrier Control Permit – Control Room Envelope Breach	April 19, 2016
09-102	NEDC, Internal Flooding – HELB, MELB, and Feedwater Line Break	1
12-057	NEDC, Air Voids in Emergency Core Cooling	0
13-005	Engineering Evaluation, The Effect of Small Air Voids on ECCS System Discharge Piping	0
92-017	NEDC, Class IS Large Bore Piping and Pipe Support Analysis Guideline	2
94-230	NEDC	
94-332	NEDC, Residual Heat Removal Minimum Flow Bypass Valve Modification	6.1
2016-036	Engineering Report, Flaw Evaluation of Service Water System Leak	0
2016-040	Engineering Report, Flaw Evaluation of Service Water System Non-Planar Flow at SW-E-9-2851-2	0

Miscellaneous Documents

Number	Title	Revision/Date
2036	Burns & Roe, Flow Diagram Reactor Building Service Water System, Sheet 1	A3
709791-1	Drawing, Drag Valve 14X14, Globe, 300 ANSI, Service Water RHR, Sheet 1	N05

Procedures

Number	Title	Revision
0-BARRIER	Barrier Control Program	21
0-CNS-WM-102	Work Implementation and Closeout	4
0.5.OPS	Operations Review of Condition Reports/Operability Determination	55
3.45	Control Room Envelope Habitability Program	2
6.HV.106	Control Room Envelope Integrity Test	4
6.SC.502	Secondary Containment Penetration Examination	19
6.2RHR.201	Power Operated Valve Inservice Test	34
6.2RHR.305	RHR Loop B Pump Low Flow Switch Channel Calibration (DIV 2)	15
7.0.5	CNS Post-Maintenance Testing	52
7.3.16.1	Agastat 7000 Series Time Delay Pickup Relay Replacement	2
7.3.21.1	Fire Barrier Seal Installation-Grouting	13

Condition Reports (CRs)

CR-CNS-2011-01063	CR-CNS-2014-04452	CR-CNS-2015-03259	CR-CNS-2016-02111
CR-CNS-2016-02232	CR-CNS-2016-03610	CR-CNS-2016-03611	CR-CNS-2016-03912
CR-CNS-2016-03963	CR-CNS-2016-04261	CR-CNS-2016-04310	CR-CNS-2016-04630
CR-CNS-2016-04647	CR-CNS-2016-04984	CR-CNS-2016-05167	CR-CNS-2016-05558
CR-CNS-2016-05628			

Work Orders

4977355	5026786	5065112

Section 1R18: Plant Modifications

Miscellaneous Documents

Number	Title	Revision/Date
4228	As-Built Structural Reactor Building Fuel Storage Pool Plan & Elevations	5
4277	Structural Reactor Building BLDG Cross Sections, Sheet 6	6
603904	Engineering Change, Relocation of Shutdown Cooling Isolation Function (RR-PS-128A/B)	0
769E522	Fuel Grapple – Mast – Refueling Platform Equipment	3
829E434	Fuel Bundle Drawing	2
455005665	Reactor Vessel Drawing	4
919D690BC	Reactor Vessel Drawing	5
NEDE-2401	GESTAR II – General Electric Standard Application for Reactor Fuel	November 2015

Procedures

Number	Title	Revision
2.2.69.2	RHR System Shutdown Operations	92
6.MISC.502	ASME Class 1 System Leakage Test	48
6.MISC.504	ASME Class 1 System Leakage Test	22

Condition Reports (CRs)

CR-CNS-2015-03807	CR-CNS-2016-01021	CR-CNS-2016-03188	CR-CNS-2016-03676
CR-CNS-2016-03869			

Work Orders

5095702	5095703

Section 1R19: Post-Maintenance Testing

Miscellaneous Documents

Number	Title	Revision/Date
	REC-P-B Trip Failure Modes and Effects Analysis	August 8, 2016
94-332	NEDC, Residual Heat Removal Minimum Flow Bypass Valve Modification	6.1

Miscellaneous Documents

Number	Title	Revision/Date
91-184	NEDC, Motor Overload Heater Sizing	5
94-230	NEDC, Vessel Head-Over Drywell Capacity Curve for Input into ECCS Analysis	5

Procedures

Number	Title	Revision
6.PC.506	Division 1 and 2 H2/O2 Analyzer Local Leak Rate Tests (IST)	21
6.1H2O.301	Division 1 H2/O2 Analyzer Checkout	24
6.1H2O.302	Division 1 H2/O2 Analyzer Calibration	16
6.1SWBP.101	RHR Service Water Booster Pump Flow Test and Valve Operability Test (Div 1)	29
6.2RHR.201	Power Operated Valve Inservice Test	34
6.2RHR.305	RHR Loop B Pump Low Flow Switch Channel Calibration (DIV 2)	15
7.0.5	CNS Post-Maintenance Testing	52
7.3.16.1	Agastat 7000 Series Time Delay Pickup Relay Replacement	2
7.3.20.3	Motor Analysis	18

Condition Reports (CRs)

CR-CNS-2012-05389	CR-CNS-2012-05401	CR-CNS-2012-05871	CR-CNS-2012-09088
CR-CNS-2014-04452	CR-CNS-2016-03860	CR-CNS-2016-04628	CR-CNS-2016-04629
CR-CNS-2016-04630	CR-CNS-2016-04633	CR-CNS-2016-04647	CR-CNS-2016-04682
CR-CNS-2016-04728			

Work Orders

4803258	5012016	5012118	5026786	5028486
5030030	5060428	5060666	5061194	5106835
5106837	5113795	5143658	5144374	

Section 1R20: Refueling and Other Outage Activities

Procedures

Number	Title	Revision
0.50.5	Outage Shutdown Safety	35
2.1.4	Normal Shutdown	152
2.1.5	Reactor Scram	73
2.1.10	Station Power Changes	112
2.2.28	Feedwater System Startup and Shutdown	104
2.2.56	Main Steam System	49
2.2.69.2	RHR System Shutdown Operations	92
6.RCS.601	Technical Specification Monitoring of RCS Heatup/Cooldown Rate	22

Condition Reports (CRs)

CR-CNS-2016-05808	CR-CNS-2016-05809	CR-CNS-2016-05814	CR-CNS-2016-05817
CR-CNS-2016-05818	CR-CNS-2016-05819	CR-CNS-2016-05820	CR-CNS-2016-05831
CR-CNS-2016-05835			

Section 1R22: Surveillance Testing

Miscellaneous Documents

Number	Title	Revision
	Control Room Logs	
2039	Drawing, Flow Diagram Control Rod Drive Hydraulic System	61
2040	Burns and Roe, Residual Heat Removal System, Sheet 1	N82

Procedures

Number	Title	Revision
0.31	Equipment Status Control	77
0.40	Work Control Program	90
2.2.69	System Operating Procedure – Residual Heat Removal System	98
2.2.70	RHR Service Water Booster Pump System	76
3.40	Primary Containment Leakage Rate Testing Program	12

Procedures

Number	Title	Revision
4.3	Reactor Manual Control System and Rod Position Information System	28
6.PC.513	Main Steam Local Leak Rate Tests	25
6.REC.201	REC Motor Operated Valve Operability Test (IST)	26
6.1RPS.310	South SDV High Water Level Switches and Transmitters Examination and Channel Calibration (DIV 1)	23
6.2RHR.101	RHR Test Mode Surveillance Operation (IST)(Div 2)	34

Condition Reports (CRs)

CR-CNS-2016-02627	CR-CNS-2016-04547	CR-CNS-2016-04577	CR-CNS-2016-04590
CR-CNS-2016-06101	CR-CNS-2016-06102	CR-CNS-2016-06165	CR-CNS-2016-06180
CR-CNS-2016-06185	CR-CNS-2016-06186	CR-CNS-2016-06205	CR-CNS-2016-06227

Work Orders

5066698

Section 1EP6: Drill Evaluation

Miscellaneous Documents

Number	Title	Revision/Date
	Cooper Nuclear Station Drill and Exercise Manual, EP DEP Evaluation Process for Limited Scope Simulator Drills, Attachment H-3	10
	DEP and Facility PI Summary for ERO Ops Crew Scenario SKL052-52-49	August 2, 2016
	DEP Performance Evaluation and Data Collection Form	August 2, 2016
SKL052-52-49	Simulator Exam Scenario 49	8

Procedures

Number	Title	Revision
EPIP 5.7.1	Emergency Action Level Technical Bases, Attachment 2	54
EPIP 5.7.1	Cooper Nuclear Station Emergency Action Level Matrix, Attachment 4	13

Section 4OA2: Problem Identification and Resolution

Miscellaneous Documents

Number	Title	Revision/Date
	HPCI Aux Lube Oil Pump Failed to Start FMEA	April 27, 2016
2001-0050	RCR	
2001-0127	RCR	
2014-004	Engineering Report, Primary Containment Isolation Valve Clarification	0
32977-A	NEDC, Excess Flow Check Valve Testing Relaxation	June 2000
791E272	Elementary Diagram – HPCI System, Sheet 10	N21
4033-55750-23	Nutherm Panel EE-STR-250-HPCI (ALOP) Schematic	N06
IN 94-68	Safety-Related Equipment Failures Caused By Faulted Indicating Lamps	September 27, 1994
LCOTR TS16-HPCI	Maintenance LCO Tracker, Week 1616	April 18, 2016
RCE 2016-02281	HPCI Declared Inoperable Twice in Two Days	0

Procedures

Number	Title	Revision
5.3.10	Maintenance Work Practice – Auxiliary Relay Setup	1
7.2.15	Service Water Pump Column Maintenance and Bowl Assembly Replacement	38
7.3.16	Low Voltage Relay Removal and Installation	22
CNS-SW-29	Cooper Nuclear Station Service Water Columns	9
EN-LI-108	Event Notification and Reporting	10
0-CNS-LI-102	Corrective Action Process	4
0-EN-LI-118	Root Cause Evaluation Process	18C5

Condition Reports (CRs)

CR-CNS-2013-02068	CR-CNS-2013-02323	CR-CNS-2013-07245	CR-CNS-2014-06809
CR-CNS-2015-00489	CR-CNS-2015-02083	CR-CNS-2015-03008	CR-CNS-2016-01061
CR-CNS-2016-01761	CR-CNS-2016-01793	CR-CNS-2016-01794	CR-CNS-2016-01798
CR-CNS-2016-01804	CR-CNS-2016-02217	CR-CNS-2016-02318	CR-CNS-2016-02342

CR-CNS-2016-02452	CR-CNS-2016-02589	CR-CNS-2016-02753	CR-CNS-2016-02881
CR-CNS-2016-03188	CR-CNS-2016-03874	CR-CNS-2016-04137	

Work Orders

4895872	5002448	50034963	5130230

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

Miscellaneous Documents

Number	Title	Date
EAW 3.8.1	Seismic Instrument Data	September 3, 2016

Procedures

Number	Title	Revision
5.1Incident	Site Emergency Incident	35
5.1Quake	Earthquake	14
5.7.1	EPIP – Emergency Classification	54
5.7.25	EPIP – Recovery Actions	21

Condition Reports (CRs)

CR-CNS-2016-05148	CR-CNS-2016-05151	CR-CNS-2016-05247	CR-CNS-2016-05249
CR-CNS-2016-05250	CR-CNS-2016-05259		

Section 4OA5: Other Activities

Miscellaneous Documents

Number	Title	Revision
EDP-048	Flood Hazard Re-Evaluation Interim Action Monitoring and Trigger Points	2
SL-012450	Cooper Nuclear Station Flood Hazard Reevaluation Report	0
SL-013017	Cooper Nuclear Station Flood Hazard Reevaluation Report Addendum B	2
2016-039	Engineering Report, Timing for Setup of Beyond Design Basis Flooding Equipment	0
5030445	Temporary Configuration Change, Beyond Design Basis Flooding Decay Heat Removal	1

Procedures

Number	Title	Revision
5.1Flood	Flood	17

Condition Reports (CRs)

CR-CNS-2015-01506	CR-CNS-2016-05211	CR-CNS-2016-05212	CR-CNS-2016-05214

Work Orders

5107422

Our inspection dates are subject to change based on your updated schedule of outage activities. If there are any questions about this inspection or the material requested, please contact James Drake at 817-200-1558 or e-mail James.Drake@nrc.gov.

INSERVICE INSPECTION DOCUMENT REQUEST

Inspection Dates: September 26, 2016, through September 30, 2016

Inspection Procedures: IP 71111.08 “Inservice Inspection (ISI) Activities”
Inspectors: Jim Drake

A. Information Requested for the In-Office Preparation Week

The following information should be sent to the Region IV office in hard copy or electronic format (ims.certrec.com preferred), in care of James Drake, by September 15, 2016, to facilitate the selection of specific items that will be reviewed during the on-site inspection week. The inspector will select specific items from the information requested below and then request from your staff additional documents needed during the on-site inspection week (Section B of this enclosure). We ask that the specific items selected from the lists be available and ready for review on the first day of inspection. Please provide requested documentation electronically if possible. If requested documents are large and only hard copy formats are available, please inform the inspector(s), and provide subject documentation during the first day of the on-site inspection. If you have any questions regarding this information request, please call the inspector as soon as possible.

Office phone: 817-200-1558, E-mail: James.Drake@nrc.gov

A.1 ISI/Welding Programs and Schedule Information

a) A detailed schedule (including preliminary dates) of:

i) Nondestructive examinations planned for ASME Code class systems and containment, performed as part of your ASME Section XI risk-informed (if applicable) and augmented inservice inspection programs during the upcoming outage.

Provide a status summary of the nondestructive examination inspection activities vs. the required inspection period percentages for this Interval by category per ASME Section XI IWX-2400 (do not provide separately if other documentation requested contains this information).

ii) Welding activities that are scheduled to be completed during the upcoming outage (ASME Code class structures, systems, or components).

iii) Examinations associated with the Boiling Water Reactor Vessel and Internals Project program (i.e., In-Vessel Visual Inspections).

b) A copy of ASME Section XI Code Relief Requests and associated NRC safety evaluations applicable to the examinations identified above

c) A list of nondestructive examination reports (ultrasonic, radiography, magnetic particle, dye penetrate, Visual VT-1, VT-2, and VT-3), which have identified relevant conditions on ASME Code Class systems since the beginning of the last refueling outage. This should include the previous Section XI pressure test(s) conducted during start up and any evaluations associated with the results of the pressure tests. The list of nondestructive examination reports should include a brief description of the structures, systems, and components where the relevant condition was identified.

d) A list with a brief description (e.g., system, material, pipe size, weld number, and nondestructive examination performed) of the welds in ASME Code Class systems which have been fabricated due to component repair/replacement activities since the beginning of the last refueling outage, or are planned to be fabricated this refueling outage.

e) If reactor vessel weld examinations required by the ASME Code are scheduled to occur during the upcoming outage, provide a detailed description of the welds to be examined and the extent of the planned examination. Please also provide reference numbers for applicable procedures that will be used to conduct these examinations.

f) A copy of any 10 CFR Part 21 reports applicable to your structures, systems, and components within the scope of Section XI of the ASME Code that have been identified since the beginning of the last refueling outage.

g) A list of any temporary non-code repairs in service (e.g., pinhole leaks).

h) Copies of the most recent self-assessments for the inservice inspection, welding, and Alloy 600 programs.

i) Copies of nondestructive examination (including calibration and flaw characterization/sizing procedures) and welding procedures that will be used during the refueling outage.

A.2 <u>Additional Information Related to All Inservice Inspection Activities</u>

a) A list with a brief description of inservice inspection-related issues (e.g., condition reports) entered into your corrective action program since the beginning of the last refueling outage (for the applicable unit). For example, a list based upon data base searches using key words related to piping, such as inservice inspection, ASME Code, Section XI, nondestructive examination, cracks, wear, thinning, leakage, rust, corrosion, or errors in piping/nondestructive examinations.

b) Provide names and phone numbers for the following program leads:

Inservice inspection contacts (examination, planning)
Containment Exams
Snubbers and Supports
Repair and Replacement Program Manager
Licensing Contact
Site Welding Engineer

B. Information to be Provided On-site to the Inspector(s) at the Entrance Meeting:

B.1 Inservice Inspection / Welding Programs and Schedule Information

a) Updated schedules for inservice inspection/nondestructive examination activities, planned welding activities, and schedule showing contingency repair plans, if available.

b) For ASME Code Class welds selected by the inspector from the lists provided from section A of this enclosure, please provide copies of the following documentation for each subject weld:

i) Weld data sheet (traveler)

ii) Weld configuration and system location

iii) Applicable Code Edition and Addenda for weldment

iv) Applicable Code Edition and Addenda for welding procedures

v) Applicable welding procedure specifications used to fabricate the welds

vi) Copies of procedure qualification records supporting the welding procedure specifications from B.1.b.v.

vii) Copies of mechanical test reports identified in the procedure qualification records above

viii) Copies of the nonconformance reports for the selected welds (if applicable)

ix) Radiographs of the selected welds and access to equipment to allow viewing radiographs (if radiographic was performed)

x) Copies of the preservice examination records for the selected welds

xi) Copies of welder performance qualifications records applicable to the selected welds, including documentation that welder maintained proficiency in the applicable welding processes specified in the welding procedure specifications (at least six months prior to the date of subject work).

xii) Copies of nondestructive examination personnel qualifications (visual test, penetrant test, ultrasonic test, and radiographic test), as applicable

c) For the inservice inspection-related corrective action issues selected by the inspector(s) from Section A of this enclosure, provide a copy of the corrective actions and supporting documentation.

d) For the nondestructive examination reports with relevant conditions on ASME Code class systems selected by the inspector from Section A above, provide a copy of the examination records, examiner qualification records, and associated corrective action documents.

e) A copy of (or ready access to) most current revision of the inservice inspection program manual and plan for the current interval.

f) For the nondestructive examinations selected by the inspector from Section A of this enclosure, provide copy of documentation supporting the procedure qualification (e.g., the Electric Power Research Institute performance demonstration qualification summary sheets). Also, include qualification documentation of the specific equipment to be used (e.g., ultrasonic unit, cables, and transducers including serial numbers) and nondestructive examination personnel qualification records.

g) If site-specific training for fall protection and/or confined space entry is required, please make arrangements for the inspector to attend the training upon arrival at the site to support the nondestructive examination/welding work schedules.

B.2 <u>Codes and Standards</u>

a) Ready access to (i.e., copies provided to the inspector(s) for use during the inspection at the on-site inspection location, or room number and location where available):

i) Applicable editions of the ASME Code (Sections V, IX, and XI) for the inservice inspection program and the repair/replacement program.

ii) Any other applicable Electric Power Research Institute and industry standards referenced in the plant procedures for welding and nondestructive examination activities.