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

August 13, 2013

Jeremy Browning, Site Vice President
Arkansas Nuclear One
Entergy Operations, Inc.
1448 SR 333
Russellville, AR 72802-0967

SUBJECT: ARKANSAS NUCLEAR ONE - NRC INTEGRATED INSPECTION REPORT 05000313/2013003 AND 05000368/2013003

Dear Mr. Browning:

On June 30, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Arkansas Nuclear One Station Units 1 and 2, facility. The enclosed inspection report documents the inspection results which were discussed on July 2, 2013, with you and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

One NRC identified and one self-revealing finding of very low safety significance (Green) were identified during this inspection. Both of these findings were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Arkansas Nuclear One.

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 Arkansas Nuclear One.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's Agencywide Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Donald B. Allen, Chief
Project Branch E
Division of Reactor Projects

Docket Nos.: 05000313, 05000368
License Nos: DPR-51; NPF-6

Enclosure: Inspection Report 05000313/2013003 and 05000368/2013003
w/ Attachments: 1. Supplemental Information
2. Request for Information for the Inservice Inspection

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SRI:DRP/E	SRI:DRP/E	RI:DRP/E	RI:DRP/E	SPE:DRP/E	C:DRS/EB1
FSanchez	BTindell	WSchaup	AFairbanks	RAzua	TFarnholtz
/RA/E	/RA/E	/RA/E	/RA/DAllen for	/RA/	/RA/
08/13/2013	08/13/2013	08/13/2013	08/13/2013	08/13/2013	08/12/2013
C:DRS/EB2	C:DRS/OB	C:DRS/PSB1	C:DRS/PSB2	C:DRS/TSB	BC:DRP/E
GMiller	MHaire	VGaddy	JDrake	RKellar	DAllen
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000313, 05000368
License:	DPR-51, NPF-6
Report:	05000313/2013003, 05000368/2013003
Licensee:	Entergy Operations Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	Junction of Hwy. 64 West and Hwy. 333 South Russellville, Arkansas
Dates:	April 1 through June 30, 2013
Inspectors:	A. Sanchez, Senior Resident Inspector B. Tindell, Senior Resident Inspector A. Fairbanks, Resident Inspector W. Schaup, Resident Inspector R. Azua, Senior Project Engineer I. Anchondo, Senior Reactor Inspector D. Bradley, Project Engineer J. Melfi, Project Engineer
Approved By:	Don Allen, Chief, Project Branch E Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000313/2013003, 05000368/2013003; 04/01/2013 - 06/30/2013; Arkansas Nuclear One, Units 1 and 2, Integrated Resident and Regional Report; Surveillance Testing, Event Followup.

The report covered a 3-month period of inspection by resident inspectors and an announced baseline inspection by region-based inspectors. Two Green non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The cross-cutting aspect is determined using Inspection Manual Chapter 0310, "Components Within the Cross-Cutting Areas." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. Inspectors documented a Green self-revealing non-cited violation of Technical Specification 6.4.1.a for the licensee's failure to implement procedures recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, the licensee failed to follow procedures for the replacement of the supply breaker for control room emergency chiller 2VE-1A. As a result, the breaker was installed incorrectly and the chiller was inoperable for over two months. Immediate corrective actions included proper installation of the breaker and procedural requirements for visual verification of breaker configuration. The licensee documented the issue in their corrective action program as CR-ANO-2-2013-00233.

  Inspectors concluded that the failure to follow Procedure 1403.179 for replacement of the train A control room emergency chiller breaker is a performance deficiency. The performance deficiency is more than minor 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, and is therefore a finding. Specifically, the loose breaker connection adversely affected the availability and reliability of the control room emergency chiller A. Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process (SDP) for Findings at Power," the inspectors determined that the finding required a detailed risk evaluation because it represented an actual loss of function of a single train for longer than its technical specification allowed outage time. The senior reactor analyst performed a detailed risk evaluation using the Arkansas Nuclear One Standardized Plant Analysis Risk models. The dominant risk sequences include a seismically-induced loss of offsite power with the failure of control room emergency chiller A. The analyst assumed that the operators and control room instrumentation could survive a peak control room temperature of 120° F, and that chiller A was susceptible to failure during a seismic event for the 83 days. None of the core damage sequences affected by this performance deficiency were important to the large, early release frequency. Therefore, based on the combined internal and seismic ICCDP of 2.9 x 10^{-7}, this finding was of very low safety significance (Green). The finding was determined to have a cross-cutting aspect in the area of human performance, associated with work practices, in that the licensee failed to use work practices that support human performance. Specifically, licensee personnel were aware of the possibility of misaligning the wire grip style lug, but failed to use adequate self and peer checking to ensure the lug was correctly installed [H.4(a)] (Section 4OA3).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a non-cited violation of Unit 2 Technical Specification 6.5.16, "Containment Leakage Rate Testing Program," for the failure to evaluate and take appropriate corrective actions to achieve acceptable performance for containment isolation valves that exceed the local leak rate administrative limit. The licensee entered this issue into the corrective action program as Condition Report CR-ANO-2-2013-01370.

  The failure to perform a cause determination and take appropriate corrective actions for containment isolation valves that exceed the local leak rate administrative limit was a performance deficiency. The performance deficiency was more than minor because it was associated with the procedure quality attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events, and is therefore a finding. Specifically, the failure to perform a cause determination and take appropriate corrective actions adversely affected the licensee's ability to ensure containment isolation valves function properly. Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process (SDP) for Findings at Power," the finding is determined to have very low safety significance because it did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components, and the finding did not involve an actual reduction in function of hydrogen igniters in the reactor containment. Since the cause of the performance deficiency occurred more than three years ago, the inspectors concluded that the finding was not representative of current licensee performance and no cross-cutting aspect was assigned (Section 1R22).

B. Licensee-Identified Violations

None

PLANT STATUS

Unit 1 began the period in refueling outage 1R24 and remained shut down for the entire inspection period as the licensee recovered from the main generator stator drop that occurred on March 31, 2013.

Unit 2 began the period in a forced outage due to the Unit 1 main generator stator drop. On April 28, 2013, operators performed a reactor startup and closed the main generator output breakers, placing Unit 2 on the grid. Unit 2 reached 100 percent power on April 30, 2013 and remained there for the rest of the period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

Summer Readiness for Offsite and Alternate ac Power Systems

a. Inspection Scope

The inspectors performed a review of preparations for summer weather for selected systems, including conditions that could lead to loss-of-offsite power and conditions that could result from high temperatures. The inspectors reviewed the procedures affecting these areas and the communications protocols between the transmission system operator and the plant to verify that the appropriate information was being exchanged when issues arose that could affect the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the transmission system operator and the plant's operations personnel during off-normal or emergency events
- The explanations for the events
- The estimates of when the offsite power system would be returned to a normal state
- The notifications from the transmission system operator to the plant when the offsite power system was returned to normal

During the inspection, the inspectors focused on plant-specific design features and the procedures used by plant personnel to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Safety Analysis Report and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. Specific documents reviewed during this inspection are listed in the attachment. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Startup transformers
- Vital buses
- Emergency diesel generators

These activities constitute completion of one sample to evaluate the readiness of offsite and alternate ac power for summer weather, as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

Partial Walkdown

a. Inspection Scope

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

- June 5, 2013, Unit 2, high pressure safety injection pumps A and C while high pressure safety injection pump B was unavailable for planned maintenance

- June 6, 2013, Unit 1, emergency diesel generator A while emergency diesel generator B was unavailable for planned maintenance

The inspectors selected the systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors focused on any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the Safety Analysis Report, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also inspected accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns in the following risk-significant plant areas:

- June 25, 2013, Unit 1, Fire Zone 95-O, north battery room
- June 25, 2013, Unit 2, Fire Zone 2098-L, cable spreading room
- June 25, 2013, Unit 2, Fire Zone NA, intake structure
- June 26, 2013, Unit 1, Fire Zone 170-Z, steam pipe area

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's individual plant examination of external events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly fire-protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed the Safety Analysis Report, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; reviewed the corrective action program to determine if licensee personnel identified and corrected flooding problems; and verified that operator actions for coping with flooding can reasonably achieve the desired outcomes. The inspectors also inspected the areas listed below to verify the adequacy of equipment seals located below the flood line, floor and wall penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, and control circuits, and temporary or removable flood barriers. Specific documents reviewed during this inspection are listed in the attachment.

- May 24, 2013, Units 1 and 2, intake structures, 366 foot level

These activities constitute completion of one flood protection measures inspection sample as defined in Inspection Procedure 71111.06-05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

Completion of Sections .1 through .5, below, constitutes completion of one sample as defined in Inspection Procedure 71111.08-05.

.1 Inspection Activities Other Than Steam Generator Tube Inspection, Pressurized Water Reactor Vessel Upper Head Penetration Inspections, and Boric Acid Corrosion Control (71111.08-02.01)

a. Inspection Scope

The inspectors observed four nondestructive examination activities and reviewed four nondestructive examination activities that included three types of examinations. The licensee did not identify any relevant indications accepted for continued service during the nondestructive examinations.

The inspectors directly observed the following nondestructive examinations:

SYSTEM	WELD IDENTIFICATION	EXAMINATION TYPE
Reactor Coolant System	Pressurizer Relief Nozzle Between W-X Axis (Report No. 1-ISI-UT-13-017)	Ultrasonic

SYSTEM	WELD IDENTIFICATION	EXAMINATION TYPE
Reactor Coolant System	Cold Leg Drain Nozzle to SE Circ Weld (Report No. 1-ISI-UT-13-020)	Ultrasonic
Main Steam	EBB-3-MS-143, I.W.A (Report No. 1-ISI-MT-13-001)	Magnetic Particle
Building Spray	HCD-8/BS-123 (Report No. 1-ISI-VT-13-042)	Visual (VT-3)

The inspectors reviewed records for the following nondestructive examinations:

SYSTEM	WELD IDENTIFICATION	EXAMINATION TYPE
Reactor Coolant System	Pipe-to-pipe weld (Report No. 1-ISI-UT-13-021)	Ultrasonic
Reactor Coolant System	Pipe-to-Cap weld (Report No.1-BOP-RT-13-011)	Radiographic
Reactor Coolant System	Reducer-to-Flange weld (Report No.1-BOP-RT-13-0070)	Radiographic
Reactor Coolant System	Pipe-to-elbow weld (Report No. 1-BOP-RT-13-012)	Radiographic

During the review and observation of each examination, the inspectors verified that activities were performed in accordance with the American Society of Mechanical Engineers (ASME) code requirements and applicable procedures. The inspectors also verified the qualifications of all nondestructive examination technicians performing the inspections were current.

These actions constitute completion of the requirements for Section 02.01.

b. Findings

No findings were identified.

.2 Vessel Upper Head Penetration Inspection Activities (71111.08-02.02)

a. Inspection Scope

No reactor vessel head inspections were performed during this outage.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control Inspection Activities (71111.08-02.03)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's boric acid corrosion control program for monitoring degradation of those systems that could be adversely affected by boric acid corrosion. The inspectors reviewed the documentation associated with the licensee's boric acid corrosion control walkdown as specified in Procedures SEP-BAC-ANO-001, "Boric Acid Corrosion Control Program Inspection and Identification of Boric Acid Leaks for ANO-1 and ANO-2," Revision 0, CEP-BAC-001, "Boric Acid Corrosion Control (BACC) Program Plan," Revision 0, and EN-DC-319, "Inspection and Evaluation of Boric Acid Leaks," Revision 8. The inspectors also reviewed the visual records of the components and equipment. The inspectors verified that the visual inspections emphasized locations where boric acid leaks could cause degradation of safety-significant components. The inspectors also verified that the engineering evaluations for those components where boric acid was identified gave assurance that the ASME code wall thickness limits were properly maintained. The inspectors confirmed that the corrective actions performed for evidence of boric acid leaks were consistent with requirements of the ASME code. Specific documents reviewed during this inspection are listed in the attachment.

These actions constitute completion of the requirements for Section 02.03.

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities (71111.08-02.04)

a. Inspection Scope

The licensee performed steam generator inspection activities during refueling outage 1R24 to determine the extent of bowing and tube-to-tube wear progression. The activities were not technical specification required inspections. The scope of the licensee's eddy current testing included:

- Bobbin testing of 454 tubes in steam generator A from tube support 09S to upper tube end.

- Bobbin testing of 446 tubes in steam generator B from tube support 09S to upper tube end.

- Full length eddy current array probe (X-probe) of 304 tubes in steam generator A (including 17 proximity tubes).

- Full length eddy current array probe (X-probe) of 308 tubes in steam generator B (including 14 proximity tubes).

- Full length eddy current array probe (X-probe) of 48 tubes in steam generator A exhibiting tube-to-tube wear.

- Full length eddy current array probe (X-probe) of 74 tubes in steam generator B exhibiting tube-to-tube wear.

- Full length eddy current array probe (X-probe) of 51 tubes in steam generator A with prior proximity signals (PRX).

- Full length eddy current array probe (X-probe) of 17 tubes in steam generator B with prior proximity signals (PRX).

The following tube degradation mechanisms were identified:

- Wear at the tube support plate intersections.
- Tube-to-tube wear.
- Tie rods bowing

At the conclusion of the eddy current testing, the licensee preventively plugged and stabilized seven tubes in steam generator A and nine tubes in steam generator B.

The inspectors observed portions of the eddy current testing being performed and verified that: (1) the appropriate probes were used for identifying the expected types of degradation, (2) calibration requirements were adhered to, and (3) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of the site-specific qualifications for the techniques being used, and verified that eddy current test data analyses were adequately performed per Electric Power Research Institute and site specific guidelines.

Finally, the inspectors review selected eddy current test data and verified that the analytical techniques used were adequate.

These actions constitute completion of the requirements for Section 02.04.

b. <u>Findings</u>

No findings were identified.

.5 Identification and Resolution of Problems (71111.08-02.05)

a. Inspection Scope

The inspectors reviewed 13 condition reports associated with inservice inspection activities, and determined that the corrective actions taken were appropriate. The inspectors concluded that the licensee had an appropriate threshold for entering inservice inspection issues into the corrective action program and had procedures that direct a root cause evaluation when necessary. The licensee also had an effective program for applying inservice inspection industry operating experience. Specific documents reviewed during this inspection are listed in the attachment.

These actions constitute completion of the requirements of Section 02.05.

b. Findings

No findings were identified.

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

.1 Quarterly Review of Licensed Operator Requalification Program

a. Inspection Scope

On June 26, 2013, the inspectors observed Units 1 and 2 licensed operators in the plant during requalification testing job performance measures. The inspectors assessed the following areas:

- Licensed operator performance
- The ability of the licensee to administer the evaluations
- Follow-up actions taken by the licensee for identified discrepancies

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

b. Findings

No findings were identified.

.2 Quarterly Observation of Licensed Operator Performance

a. Inspection Scope

The inspectors observed the performance of on-shift licensed operators in the plant's main control room. The inspectors assessed the operators' adherence to plant procedures, including conduct of operations procedures and other operations department policies. The inspectors observed the operators' performance during the following periods of heightened activities:

- April 28, 2013, Unit 2, reactor startup
- June 18, 2013, Unit 1, train B undervoltage surveillances

These activities constitute completion of two quarterly licensed operator performance samples as defined in Inspection Procedure 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- April 19, 2013, Unit 1, unplanned unavailability of emergency diesel generator A

- June 10, 2013, Unit 2, high pressure safety injection B flow control valve 480 Volt breaker replacement

The inspectors reviewed events where ineffective equipment maintenance had resulted in failures and independently verified the licensee's actions to address system performance or problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b)
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring
- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or (a)(2)
- Establishing appropriate performance criteria
- Establishing appropriate and adequate goals and corrective actions

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- January 9, 2013, Units 1 and 2, heavy equipment driving in the switchyard
- May 7, 2013, Unit 2, service water sluice gate 2CV-1472-5 failed to open
- March 31, 2013, Units 1 and 2, Bigge lift rig collapse and generator stator drop
- April 11, 2013, Unit 1, reactor building hatch open during tornado warning
- April 23, 2013, Unit 1, outage activities following the main generator stator drop
- May 4, 2013, Units 1 and 2, dropped stator and damaged carriage removal
- May 20, 2013, Units 1 and 2, heavy equipment in train bay

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of seven maintenance risk assessments and emergent work control inspection samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- December 5, 2012, Units 1 and 2, startup transformer 2 sudden pressure relays wetting during design basis flood
- May 7, 2013, Unit 2, service water sluice gate 2CV-1472-5 failed to open
- April 11, 2013, Unit 1, reactor building pipe support EBB-6-H13 not fully engaged
- April 24, 2013, Unit 2, debris identified in containment during closeout
- May 17, 2013, Unit 1, emergency diesel generator A fretting wear on the turbocharger inlet air turning box north-side support legs
- June 7, 2013, Unit 2, wetting of emergency diesel generator B fuel oil transfer pump

The inspectors selected these operability and functionality issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure technical specification operability was properly justified and to verify the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and Safety Analysis Report to the licensee's evaluations to determine whether the components or systems were operable or functional. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of six operability evaluations inspection samples as defined in Inspection Procedure 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

Temporary Modifications

a. Inspection Scope

To verify that the safety functions of important safety systems were not degraded, The inspectors reviewed the following temporary modifications:

- April 23, 2013, Unit 1, source range nuclear instrument NI-501 modification for fuel movement

- April 15, 2013, Unit 1, startup transformer 1 temporary power supply to vital buses A3 and A4

- April 15, 2013, Unit 1, startup transformer 2 temporary power supply to vital buses A3 and A4 buses through temporary switchgear

The inspectors reviewed the temporary modifications and the associated safety-evaluation screening against the system design bases documentation, including the Safety Analysis Report and the technical specifications, and verified that the modification did not adversely affect the system operability or availability. The inspectors also verified that the installation and restoration were consistent with the modification documents and that configuration control was adequate. Additionally, the inspectors verified that the temporary modification was identified on control room drawings, appropriate tags were placed on the affected equipment, and licensee personnel evaluated the combined effects on mitigating systems and the integrity of radiological barriers. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three samples for temporary plant modifications, as defined in Inspection Procedure 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following post-maintenance activities to verify that test activities were adequate to ensure system operability and functional capability:

- May 21, 2013, Unit 2, main steam supply valve CV-1000-1, from steam generator A to emergency feedwater pump turbine 2K-3, following cleaning, inspection, and lubrication of actuator and meggering of the motor

- June 6, 2013, Unit 1, VCH-4B, vital switchgear emergency chiller B, following planned maintenance

- June 13, 2013, Unit 1, P-35A, reactor building spray pump A , following bearing and seal replacement

- June 14, 2013, Unit 1, K-4B, emergency diesel generator B , following generator bearing replacement

- April 23, 2013, Alternate AC Diesel Generator Bus 2A9 and the Alternate AC Diesel Generator Following Repairs from the Unit 1 Dropped Stator Event

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities to verify that the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; and test instrumentation was appropriate.

The inspectors evaluated the activities against the technical specifications, the Safety Analysis Report, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five post-maintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. <u>Findings</u>

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. <u>Inspection Scope</u>

The inspectors reviewed the outage safety plan and contingency plans for the Unit 1 refueling outage and the Unit 2 forced outage, to confirm that licensee personnel had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense in depth. During the refueling and forced outages, the inspectors monitored licensee controls over the outage activities listed below, as applicable.

- Configuration management, including maintenance of defense in depth, is commensurate with the outage safety plan for key safety functions and compliance with the applicable technical specifications when taking equipment out of service

- Clearance activities, including confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing

- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error

- Status and configuration of electrical systems to ensure that technical specifications and outage safety-plan requirements were met, and controls over switchyard activities

- Monitoring of decay heat removal processes, systems, and components

- Verification that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system

- Reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss

- Controls over activities that could affect reactivity

- Refueling activities, including fuel handling

- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the containment to verify that debris had not been left which could block emergency core cooling system suction strainers

- Licensee identification and resolution of problems related to refueling outage activities

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one refueling outage and one other outage inspection samples, as defined in Inspection Procedure 71111.20-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Safety Analysis Report, procedure requirements, and technical specifications to ensure that the surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations and root causes
- Reference setting data
- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- September 24, 2012, Unit 2, letdown isolation valve 2CV-4832-2 local leak rate test

- February 10, 2013, Units 1 and 2, alternate ac diesel generator quarterly test

- May 1, 2013, Unit 2, remote pressurizer proportional heater test

- May 22, 2013, Unit 2, emergency feedwater pump A inservice test

- May 29, 2013, Unit 2, emergency diesel generator A monthly test

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five surveillance testing inspection samples (one pump or valve inservice test sample, one containment isolation valve test sample, and three routine surveillance testing samples) as defined in Inspection Procedure 71111.22-05.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of Unit 2 Technical Specification 6.5.16, “Containment Leakage Rate Testing Program,” for the failure to evaluate and take appropriate corrective actions to achieve acceptable performance for containment isolation valves that exceed the local leak rate administrative limit.

Description. On February 28, 2011, letdown isolation valve 2CV-4823-2 exceeded the local leak rate administrative limit, which was documented in CR-ANO-2-2011-00800. Work was scheduled to be performed on the air operator for the valve; however, no valve seat work was planned or performed. On March 11, 2011, after completion of work on the air operator, the valve exceeded the local leak rate administrative limit. The licensee generated a condition report that was closed to the work order process without a cause evaluation or corrective actions. On September 24, 2012, the valve again exceeded the as-found local leak rate administrative limit, which was documented in CR-ANO-2-2012-02270. The response stated that there were no programmatic requirements and no technical specification implications relative to containment integrity and/or leakage as a result of the leakage from valve 2CV-4823-2 exceeding its administrative limit; therefore, the leak rate from valve 2CV-4823-2 was acceptable. The inspectors noted that the valve was scheduled for repair in the spring of 2014.

The inspectors independently reviewed Unit 2 Technical Specification 6.5.16, “Containment Leakage Rate Testing Program” and determined that the licensee’s program is required to implement Nuclear Energy Institute 94-01, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” Revision 2-A. The standard states, in part, that a cause determination should be performed and corrective actions identified that focus on those activities that can eliminate the identified cause of a failure with appropriate steps to eliminate recurrence. A failure, as defined by the standard, is exceeding an administrative limit and not the total failure of the valve.

The inspectors reviewed the licensee’s corrective action program documents and their containment leakage rate testing program documents, and determined that they did not meet the technical specification required guidance. Specifically, the licensee’s programs did not specify that a cause determination be performed for conditions where containment isolation valves exceed their administrative limits. In addition, there was no guidance to ensure that corrective actions address the cause of the failure. The inspectors also noted that the licensee was not treating these items as degraded conditions to ensure that they were corrected in a timely manner. Based on the above and the licensee’s statements that the leakage from 2CF-4823-2 was acceptable, the inspectors concluded that the licensee had not adequately implemented Nuclear Energy Institute 94-01, as required by Technical Specification 6.5.16.

The inspectors concluded that because the licensee’s program was established more than three years ago, the failure to adequately implement the guidance was not representative of current licensee performance.

Analysis. The failure to perform a cause determination and take appropriate corrective actions for containment isolation valves that exceed the local leak rate administrative limit is a performance deficiency. The performance deficiency is more than minor because it was associated with the procedure quality attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events, and is therefore a finding. Specifically, the failure to perform a cause determination and take appropriate corrective actions adversely affected the licensee's ability to ensure containment isolation valves function properly. Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process (SDP) for Findings at Power," the finding is determined to have very low safety significance because it did not represent an actual open pathway in the physical integrity of reactor containment, containment isolation system, or heat removal components, and the finding did not involve an actual reduction in function of hydrogen igniters in the reactor containment. Since the cause of the performance deficiency occurred more than three years ago, the inspectors concluded that the finding was not representative of current licensee performance and no cross-cutting aspect was assigned.

Enforcement. Unit 2 Technical Specification 6.5.16, "Containment Leakage Rate Testing Program," states, in part, that a program shall be established to implement the leakage rate testing of the containment as required by 10 CFR Part 50, Appendix J, Option B, "Performance-Based Requirements." This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995. Regulatory Guide 1.163, Section C, "Regulatory Position," further states, in part, that NEI 94-01, Revision 0, dated July 26, 1995, "Industry Guideline for Implementing Performance Based Option of 10 CFR 50, Appendix J" provides methods for complying with the provisions of Option B in Appendix J to 10 CFR Part 50. Contrary to the above, as of June 30, 2013, the licensee failed to implement a program for leakage rate testing of the containment in accordance with Technical Specification 6.5.16. Specifically, Nuclear Energy Institute 94-01, Section 10.2.3.4, states, in part, that if test results are not acceptable, then a cause determination should be performed and corrective actions identified that focus on those activities that can eliminate the identified cause of the failure. A failure, as defined by the standard, is exceeding an administrative limit and not the total failure of the valve. However, the licensee's program for containment leakage rate testing did not require a cause determination and identification of corrective actions to eliminate the cause of the failure. The licensee documented this failure in Condition Report CR-ANO-2-2013-01370. Because this finding is of very low safety significance and has been entered into the corrective action program, this violation is being treated as a non-cited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000368/2013003-01, "Failure to Evaluate and Correct Excessive Containment Isolation Valve Leakage."

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the performance indicator data submitted by the licensee for the first quarter 2013 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings were identified.

.2 Safety System Functional Failures (MS05)

a. Inspection Scope

The inspectors sampled licensee submittals for the safety system functional failures performance indicator for both Units 1 and 2 for the period from the first quarter 2012 through the first quarter 2013. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, and NUREG-1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73." The inspectors reviewed the licensee’s operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports, and NRC integrated inspection reports for the period of January 2012 through March 2013, to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two safety system functional failures samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.3 Reactor Coolant System Specific Activity (BI01)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity performance indicator for both Units 1 and 2 for the period from the second quarter 2012 through the first quarter 2013. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's reactor coolant system chemistry samples, technical specification requirements, issue reports, event reports, and NRC integrated inspection reports for the period of April 2012 through March 2013, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two reactor coolant system specific activity samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Leakage (BI02)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for both Units 1 and 2 for the period from the second quarter 2012 through the first quarter 2013. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's operator logs, reactor coolant system leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of April 2012 through March 2013 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of two reactor coolant system leakage samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective actions. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Licensee's Actions to Resolve Substantive Cross-Cutting Issue

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors focused their review on substantive cross-cutting issue H.1(b), dealing with the licensee's ability to use conservative decision making when evaluating and correcting problems (see Manual Chapter 0310, "Components Within the Cross-Cutting Areas," Dated October 28, 2011, Section 06). The inspectors also discussed performance improvement details with licensee representatives, and performed a review of licensee initiatives to address deficiencies in the conservative decision making process. Documents reviewed by the inspectors are listed in an attachment to this report.

These activities constitute completion of one in-depth problem identification and resolution sample as defined in Inspection Procedure 71152-05.

b. Findings and Observations

No findings were identified. Overall, the licensee's recovery plan appeared to address the appropriate deficiencies necessary for performance improvement.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

(Closed) LER 05000368/2013-002-00, An Inoperable Emergency Control Room Chiller Due to Maintenance Error Results in a Prevented Safety Function.

On February 4, 2013, at 1255 CST, control room emergency chiller 2VE-1A breaker tripped shortly after the chiller was started. 2VE-1A is one of the two control room emergency chillers common to both Units 1 and 2. The licensee concluded that the cause of the breaker trip was that the "C" phase load side wire lug was not properly connected when the breaker was installed on November 15, 2012, resulting in a loose connection between the lug and the breaker stab. The condition was corrected and 2VE-1A was declared operable on February 6, 2013. The issue was entered into the corrective action program as Condition Report CR-ANO-2-2013-0233. The licensee's corrective actions, as a result of the incorrectly installed breaker, included performing a human performance error review, including additional procedural requirements for visual verification of lug configuration for future breaker replacements, and reinspecting all previously replaced breakers identified in the extent of condition of the apparent cause evaluation. A Green self-revealing non-cited violation is documented below. This licensee event report is closed.

Failure to Correctly Install Control Room Emergency Chiller Supply Breaker

Introduction. Inspectors documented a Green self-revealing non-cited violation of Technical Specification 6.4.1.a for the licensee's failure to implement procedures recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Specifically, the licensee failed to follow procedures for the replacement of the supply breaker for control room emergency chiller 2VE-1A. As a result, the breaker was installed incorrectly and the chiller was inoperable for over two months.

Description. On February 4, 2013, the breaker for control room emergency chiller 2VE-1A tripped shortly after the chiller was started. When the electricians removed the molded case circuit breaker for testing they identified that the C phase load side wire lug was not properly installed in the breaker; the lug that tightens the wire down to the breaker stab was installed in front of the breaker stab instead of over it. This resulted in a loose connection between the lug and the breaker stab.

The licensee had installed the breaker in accordance with Procedure 1403.179, "Molded Case Circuit Breaker Testing," Revision 20. Step 6.2.3 of Attachment 2 directed personnel to re-terminate the wires on the breaker. The location of this equipment made direct visual observation difficult necessitating the use of equipment, such as mirrors, to confirm proper installation. Although personnel installing the breaker were aware of the potential to incorrectly install the lug, they chose not to perform a visual verification of the connection, believing that if they pulled hard on the wires, and the wires did not pull out, it would confirm the lugs were installed properly. This assumption was incorrect because the wire could still be tightly pinched against the lug with the stab located outside of the lug. The licensee concluded that the causes of the incorrectly installed breaker were inadequate self-checks and peer-checks.

The breaker, which was installed on November 15, 2012, passed a monthly surveillance test directly after the post maintenance test and then again in December and January. Even though the breaker passed three surveillance tests after its replacement, the licensee submitted a licensee event report because they concluded that the control room emergency chiller had not been operable because it had a loose electrical connection since November.

The licensee documented the issue in their corrective action program as CR-ANO-2-2013-00233. After repairs to the 2VE-1A breaker were made, including verification that the lug was correctly installed, a surveillance test was successfully completed on February 6, 2013. Other subsequent corrective actions included a human performance error review and additional procedural requirements for visual verification of the wire/lug connection for future breaker replacements. In addition, the licensee reinspected all previously replaced breakers identified in the apparent cause evaluation extent of condition.

Analysis. Inspectors concluded that the failure to follow Procedure 1403.179 for replacement of the A train control room emergency chiller breaker is a performance deficiency. The performance deficiency is more than minor 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, and is therefore a finding. Specifically, the loose breaker connection adversely affected the availability and reliability of the control room emergency chiller A. Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process (SDP) for Findings at Power," the inspectors determined that the finding required a detailed risk evaluation because it represented an actual loss of function of at least a single train for longer than its technical specification allowed outage time.

The senior reactor analyst performed a detailed risk evaluation using the Arkansas Nuclear One Standardized Plant Analysis Risk models Version 8.19 for Unit 1 and Version 8.21 for Unit 2, and various hand calculations. Additionally, the analyst used the seismic risk quantification method described in the Risk Assessment of Operational Events Handbook, Volume 2, "External Events." The following calculations were performed:

- Internal Initiators

  The analyst noted that the control room emergency chillers are only important to risk if the control room chilled water system is not available. The chilled water system is a fully functional backup to the emergency chillers provided they have electrical power. The chilled water system requires offsite power from either unit to function. Therefore, the dominant risk sequences for the control room emergency chillers will be upon loss of offsite power to both units.

  The loss of offsite power frequency for either unit at Arkansas Nuclear One is 2.84×10^{-2}/year as established in the SPAR model. The analyst used the conditional probabilities provided in Table 9 of the Idaho National Laboratories "Loss of Offsite Power," 2011 Update, dated February 2013, to calculate the frequency of both units experiencing a loss of offsite power at the same time. The combined frequency of a loss of offsite power affecting both units at Arkansas Nuclear One was 1.42×10^{-2}/year.

  The analyst reviewed Engineering Report 95-R-0013-01, "Control Room Post Accident Ambient Temperature Requirements to determine the peak temperature limits for control room functionality. The limiting components were the high pressure injection flow instruments in Unit 2 which were designed to survive ambient control room temperatures of 122° F. As a bounding assumption, the analyst assumed that the operators and control room instrumentation could survive a peak of 120° F. From calculation CALC-10-E-0010-05, the analyst noted that Unit 2 heated up more rapidly than Unit 1 upon a postulated loss of cooling with 120° F being reached in 16.6 hours. Using the SPAR model, the analyst calculated a loss of offsite power nonrecovery probability for Unit 2 of

3.4×10^{-2}. This resulted in an unrecovered frequency of losing the control room chilled water system of 4.8×10^{-4}/year.

Using the SPAR model, the analyst estimated the failure probability of the control room emergency chillers (2.1×10^{-4}) and Chiller 1B (2.4×10^{-2}), assuming that Chiller 1A failed from the performance deficiency. Assuming that failure of all cooling for greater than 16.6 hours would require a control room abandonment, the analyst set the conditional core damage probability to 0.1 as assumed in the Electric Power Research Institute, fire-induced vulnerability evaluation method. The baseline conditional core damage frequency ($CCDF_{Base}$) for this performance deficiency was calculated by multiplying the unrecovered frequency of losing the control room chilled water system ($F_{NR\text{-}LOOP}$) with the failure probability of both trains of emergency chillers (P_{sys}) and the conditional core damage probability of a main control room abandonment (CCDP) as follows:

$$\begin{aligned} CCDF_{Base} &= F_{NR\text{-}LOOP} \ * \ P_{sys} \ * \ CCDP \\ &= 4.8 \times 10^{-4}/\text{year} \ * \ 2.1 \times 10^{-4} \ * \ 0.1 \\ &= 1.0 \times 10^{-8}/\text{year} \end{aligned}$$

The finding conditional core damage frequency ($CCDF_{Case}$) was calculated by assuming the failure probability of the chilled water system was now the failure probability of Chiller 1B (P_{train}) as follows:

$$\begin{aligned} CCDF_{Case} &= F_{NR\text{-}LOOP} \ * \ P_{train} \ * \ CCDP \\ &= 4.8 \times 10^{-4}/\text{year} \ * \ 2.4 \times 10^{-2} \ * \ 0.1 \\ &= 1.2 \times 10^{-6}/\text{year} \end{aligned}$$

The analyst noted that the failure of Chiller 1A resulted from the improper termination of the associated breaker. The analyst assumed that the last time the breaker was successfully cycled resulted in the termination being incapable of providing sufficient current for the next start. The exposure period (EXP) was then determined to be the 25 days from the last successful test on January 10, 2013, until the observed failure on February 4, 2013, plus the 2 days it took to repair the condition and return the chiller to a functional status. Therefore, the incremental conditional core damage probability (ICCDP) for this performance deficiency was calculated as follows:

ICCDP $= (CCDF_{Case} - CCDF_{Base}) * EXP / 365$

$= (1.2 \times 10^{-6}/\text{year} - 1.0 \times 10^{-8}/\text{year}) * 27 \text{ days} / 365 \text{ days/year}$

$= 8.4 \times 10^{-8}$

- <u>Seismic Initiator</u>

  The analyst used the plant-specific SPAR, Version 8.19 for Unit 1 and Version 8.21 for Unit 2 and a seismic model prepared as described in the Risk Assessment of Operational Events Handbook, Volume 2, "External Events," to quantify the risk of this condition. To qualify the affect of the performance deficiency on the seismic risk, the analyst made the following assumptions:

  - A seismic event that caused the failure of the ceramic insulators in the main switchyard would result in a loss of offsite power
  - A loss of offsite power caused by a seismic event would not be recoverable over the 24-hour response period assumed in this evaluation
  - Because differential movement is all that is necessary for failure of the improperly terminated power cable, the analyst assumed that the fragility of the termination was the same as the fragility of the ceramic insulators

  The analyst used 10 bins to characterize the peak ground acceleration during a postulated seismic event. In accordance with the Handbook rules, the frequency of a seismically induced loss of offsite power was calculated as 8.9×10^{-5}/year. In a similar manner, the frequency of a seismically-induced loss of offsite power with the failure of Control Room Emergency Chiller 1A was 3.8×10^{-5}/year.

  Using the method described under internal initiators, the analyst calculated a $CCDF_{Base}$ of 7.8×10^{-9}/year and a $CCDF_{Case}$ of 9.0×10^{-7}/year. Assuming that Chiller 1A was susceptible to failure during a seismic event for the 83 days from the installation of the breaker on November 15, 2012 until it was restored to a functional state on February 6, 2013, the ICCDP for seismic events was calculated to be 2.0×10^{-7}.

In accordance with NRC Inspection Manual Chapter 0609, Appendix H, Table 5.1, "Phase 1 Screening – Type A Findings at Full Power," none of the core damage sequences affected by this performance deficiency were important to the large, early release frequency. Therefore, based on the combined internal and seismic ICCDP of 2.9×10^{-7}, this finding was of very low safety significance (Green).

The finding was determined to have a cross-cutting aspect in the area of human performance, associated with work practices, in that the licensee failed to use work practices that support human performance. Specifically, licensee personnel were aware of the possibility of misaligning the wire grip style lug, but failed to use adequate self and peer checking to ensure the lug was correctly installed [H.4(a)].

Enforcement. Technical Specification 6.4.1.a requires, in part, that written procedures be implemented covering the activities in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9, specifies that procedures for performing maintenance that can affect the performance of safety-related equipment should be properly pre-planned and completed in accordance with written procedures and documented instructions appropriate to the circumstances. Licensee Procedure 1403.179, "Molded Case Circuit Breaker Testing," Revision 20, was a written procedure that implemented maintenance activities that can affect the performance of safety-related equipment. Procedure 1403.179, Attachment 2, Step 6.2.3 stated, in part, to re-terminate the wires on the breaker. Contrary to the above, the licensee failed to implement procedures covering maintenance activities that could affect the performance of safety-related equipment. Specifically, on November 15, 2012, the licensee failed to follow Procedure 1403.179 and properly re-terminate the wires on the train A control room emergency chiller supply breaker. After repairs to the 2VE-1A breaker were made, including verification that the lug was correctly installed, a surveillance test was successfully completed on February 6, 2013. Because this finding is of very low safety significance and has been entered into the corrective action program as Condition Report CR-ANO-2-2013-00233, this violation is being treated as a non-cited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000368/2013003-02, "Failure to Correctly Install Control Room Emergency Chiller Supply Breaker."

4OA5 Other Activities

.1 (Discussed) NRC Temporary Instruction 2515/182, "Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping and Tanks"

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued a guidance document, Nuclear Energy Institute 09-14, "Guideline for the Management of Buried Piping Integrity" (ADAMS Accession No. ML1030901420) to describe the goals and commitments made by the licensee resulting from this underground piping and tank initiative. On December 31, 2010, the Nuclear Energy Institute issued Revision 1 to Nuclear Energy Institute 09-14 (ADAMS Accession No. ML110700122) with an expanded scope of components which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued Temporary Instruction 2515/182, "Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks," to gather information related to the industry's implementation of this initiative.

a. Inspection Scope

The inspectors reviewed the licensee's programs for buried pipe, underground piping, and tanks in accordance with Temporary Instruction 2515/182 to determine if the program attributes and completion dates identified in Sections 3.3 A and 3.3 B of

Nuclear Energy Institute 09-14, Revision 1, were contained in the licensee's program and implementing procedures. For the buried pipe and underground piping program attributes with completion dates that had passed, the inspectors reviewed records to determine if the attribute was in fact complete.

b. Findings

No findings were identified.

.2 (Closed) Temporary Instruction 2515/187, Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns

a. Inspection Scope

Inspectors verified that licensee's walkdown packages for the Units 1 and 2 intake structures contained the elements as specified in Nuclear Energy Institute 12-07 Walkdown Guidance.

The inspectors independently performed a walkdown of the Units 1 and 2 intake structures. The inspectors confirmed that the licensee verified the following flood protection features:

- External visual inspection for indications of degradation that would prevent its credited function from being performed was performed
- Critical structure, system, and component dimensions were measured
- Available physical margin, where applicable, was determined
- Flood protection feature functionality was determined using either visual observation or by review of other documents

The inspectors verified that non-compliances with current licensing requirements, and issues identified in accordance with the 10 CFR 50.54(f) letter, Item 2.g of Enclosure 4, were entered into the licensee's corrective action program. In addition, issues identified in response to Item 2.g that could challenge risk significant equipment and the licensee's ability to mitigate the consequences will be subject to additional NRC evaluation.

b. Findings

No findings identified.

.3 (Closed) Temporary Instruction 2515/188, Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns

a. Inspection Scope

The inspector independently performed a seismic walkdown of Unit 2 2CV-1052, steam generator B atmospheric dump control valve.

Additionally, inspectors verified that items that could allow the spent fuel pool to drain down rapidly were walked down by the licensee.

The inspectors independently verified that the following seismic features were free of potential adverse seismic conditions:

- Anchorage was free of bent, broken, missing or loose hardware
- Anchorage was free of corrosion that was more than mild surface oxidation
- Anchorage was free of visible cracks in the concrete near the anchors
- Anchorage configuration was consistent with plant documentation
- SSCs would not be damaged from impact by nearby equipment or structures
- Overhead equipment, distribution systems, ceiling tiles and lighting, and masonry block walls were secure and not likely to collapse onto the equipment
- Attached lines had adequate flexibility to avoid damage
- The area appeared to be free of potentially adverse seismic interactions that could cause flooding or spray in the area
- The area appeared to be free of potentially adverse seismic interactions that could cause a fire in the area
- The area appeared to be free of potentially adverse seismic interactions associated with housekeeping practices, storage of portable equipment, and temporary installations (e.g., scaffolding, lead shielding)

Observations made during the walkdown that could not be determined to be acceptable were entered into the licensee's corrective action program for evaluation.

b. Findings

No findings identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On May 16, 2013, the inspectors presented the inspection results of the review of inservice inspection activities to Mr. D. James, Nuclear Safety Assurance Director, and other members of the licensee staff. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On July 2, 2013, the inspectors presented the inspection results to Mr. J. Browning, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

A. Remer, Project Manager
B. Greeson, Engineering, Procurement Manager
D. Hughes, Engineering Supervisor
D. James, Nuclear Safety Assurance Director
D. Meatheany, Steam Generator Lead
D. Perkins, Maintenance Manager
J. Browning, Site Vice President
J. Gobell, Welding Engineer
J. Tobin, Security Manager
K. Panther, Nondestructive Examination Lead
M. Chisum, General Manager Plant Operations
M. Hall, Licensing Specialist
N. Mosher, Licensing Specialist
P. Schlutermor, Boric Acid Lead
R. Fuller, Nuclear Oversight Manager
S. Pyle, Licensing Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000368/2013003-01	NCV	Failure to Evaluate and Correct Excessive Containment Isolation Valve Leakage (Section 1R22)
05000368/2013003-02	NCV	Failure to Correctly Install Control Room Emergency Chiller Supply Breaker (Section 40A3)

Closed

05000368/2013-002-00	LER	An Inoperable Emergency Control Room Chiller Due to Maintenance Error Results in a Prevented Safety Function (Section 4OA3)
2515/187	TI	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns (Section 4OA5.2)

2515/188	TI	Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns (Section 4OA5.3)

Discussed

2515/182	TI	Review of the Implementation of the Industry Initiative to Control Degredation of Underground Piping and Tanks (Section 4OA5.1)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PROCEDURES

NUMBER	TITLE	REVISION
OP-1203.025	Natural Emergencies	040
ENS-DC-199	Off Site Power Supply Design Requirements Nuclear Plant Interface Requirements	8
OP-1203.037	Abnormal ES Bus Votage and Degraded Offsite Power	010
OP-1202.007	Degraded Power	012
5310.002	Offsite Power System Voltage Reevaluation	002
ENS-DC-201	ENS Transmission Grid Monitoring	6

Section 1R04: Equipment Alignment

PROCEDURES

NUMBER	TITLE	REVISION
OP-1104.036	Emergency Diesel Generator Operation	065
OP-2104.039	HPSI System Operation	073
OP-1015.016	Unit Two Operations Forms	036
OP-1015.001	Conduct of Operations	096
OP-2106.006	Emergency Feedwater System Operations	083

CALCULATION

NUMBER	TITLE	REVISION
91-E-0016-154	Piping Qualification of line 2DCB-2-4 from anchor 2DCB-2-H5 to capped free end	040

CONDITION REPORT

CR-ANO-2-2013-01194

Section 1R05: Fire Protection

PROCEDURES

NUMBER	TITLE	REVISION
PFP-U1	ANO Pre-Fire Plan Unit 1	15
PFP-U2	ANO Pre-Fire Plan Unit 2	11

Section 1R06: Flood Protection Measures

PROCEDURES

NUMBER	TITLE	REVISION
OP-1104.029	Service Water and Auxiliary Cooling System	99
OP-2104.029	Service Water System Operations	93

CONDITION REPORTS

CR-ANO-1-2003-0584	CR-ANO-2-2006-0367	CR-ANO-1-2011-0495	CR-ANO-C-2012-0616
CR-ANO-1-2012-1571	CR-ANO-1-2012-1627	CR-ANO-2-2012-2967	

MISCELLANEOUS

NUMBER	TITLE	REVISION
ER 963202E101	Intake Structure Roof Missile Shield Rain Guard Installation	0

Section 1R08: Inservice Inspection Activities

PROCEDURES

NUMBER	TITLE	REVISION
CEP-NDE-0404	Manual Ultrasonic Examination of Ferritic Piping Welds (ASME XI)	5
CEP-NDE-0255	Radiographic Examination ASME, ANSI, AWS, Welds, and Components	6
CEP-NDE-0400	Ultrasonic Examination	3

Section 1R08: Inservice Inspection Activities

PROCEDURES

NUMBER	TITLE	REVISION
CEP-NDE-0731	Magnetic Particle Examination (MT) for ASME Section XI	3
CEP-NDE-0504	Ultrasonic Examination of Small Bore Diameter Piping for Thermal Fatigue Damage	2
CEP-NDE-0485	Manual Ultrasonic Examination of Vessel Nozzle Inside Radius (Non-App VIII)	9
SEP-BAC-ANO-001	Boric Acid Corrosion Control Program Inspection And Identification Of Boric Acid Leaks For ANO-1 And ANO-2	0
CEP-BAC-001	Boric Acid Corrosion Control (BACC) Program Plan	0
EN-DC-319	Inspection and Evaluation of Boric Acid Leaks	8

MISCELLANEOUS

NUMBER	TITLE	DATE
	ANO-1 Steam Generator Tube Inspection Discussion Points	May 10, 2013

CONDITION REPORTS

CR-ANO-1-2012-00137	CR-ANO-1-2012-00142	CR-ANO-1-2012-00155
CR-ANO-1-2012-01470	CR-ANO-1-2012-01391	CR-ANO-1-2013-00635
CR-ANO-1-2012-00831	CR-ANO-1-2012-01358	CR-ANO-1-2012-01362
CR-ANO-1-2012-01363	CR-ANO-1-2012-01387	CR-ANO-1-2012-01610
CR-ANO-1-2013-00479		

WORK ORDERS

338728-03 338729-03

Section 1R11: Licensed Operator Requalification Program

MISCELLANEOUS

NUMBER	TITLE	REVISION
A1JPM-RO-AOP32	Perform Spent Fuel Pool Makeup	1
A1JPM-RO-AOP15	Followup Actions for Remote Shutdown, without Auxiliary Feedwater Pump	5
A2JPM-RO-2RS2A	Perform Startup of 2Y2224 (Swing Inverter for 2RS2) (Alternate Success Path)	5
A2JPM-RO-LOF01	Align Condensate Pump for Start During a Loss of All Feedwater Event	4

PROCEDURE

NUMBER	TITLE	REVISION
OP-1105.009	CRD System Operating Procedure	42

Section 1R12: Maintenance Effectiveness

WORK ORDER

00286870-01

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

PROCEDURES

NUMBER	TITLE	REVISION
COPD-024	Risk Assessment Guidelines	45
COPD-024	Risk Assessment Guidelines	46
OP-1015.033	ANO Switchyard and Transformer Yard Controls	20
OP-1015.033	ANO Switchyard and Transformer Yard Controls	23
OP-1203.025	Natural Emergencies	35

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

PROCEDURES

NUMBER	TITLE	REVISION
COPD-024	Risk Assessment Guidelines	45
EN-WM-104	On Line Risk Assessment	7
EN-OP-119	Protected Equipment Postings	5
OP-1015.048	Shutdown Operations Protection Plan	005
EN-OU-108	Shutdown Safety Management Program (SSMP)	5
OP-2203.008	Natural Emergencies	24
EN-OP-111	Operational Decision-Making Issue (ODMI) Process	10
EN-OP-116	Infrequently Performed Tests or Evolutions	11

CONDITION REPORTS

CR-ANO-C-2013-0063 CR-ANO-2-2013-1029

MISCELLANEOUS

NUMBER	TITLE	REVISION
	1R24 Outage Risk Assessment Team Report	2
	Job Hazard Analysis for Removal of Stator and Goldhofer from the Train Bay	

Section 1R15: Operability Evaluations

PROCEDURES

NUMBER	TITLE	REVISION
EN-OP-104	Operability Evaluations	5
OP-1203.025	Natural Emergencies (Unit 1)	40
OP-2203.008	Natural Emergencies (Unit 2)	25

CONDITION REPORTS

CR-ANO-C-2012-03071	CR-ANO-C-2012-03371	CR-ANO-1-2013-00183
CR-ANO-C-2013-00787	CR-ANO-2-2013-00855	CR-ANO-2-2013-01029

CR-ANO-2-2013-01205	CR-ANO-1-2013-01458	CR-ANO-1-2011-02277

ENGINEERING CHANGES

33072	35761

WORK ORDERS

52398755-01	52326271-01	52397520-01

MISCELLANEOUS

NUMBER	TITLE	REVISION
TDQ011 0050	Instructions for Qualitrol Pressure Indicator Relay 509-100, IED 509 series, 900 series, 910 series	0
ULD-0-TOP-17	ANO Flooding Topical	0

DRAWINGS

NUMBER	TITLE	REVISION
EBB-6-H13	Hanger Detail Steam Generator	1
MS-228	Small Pipe Isometric Steam Generator E-24B Upper Tube Sheet South Vent	3

CALCULATIONS

NUMBER	TITLE	REVISION
92-E-0077-08	Maximum LPI Flow from the RB Sump	0
80D-1103-02	OTSG Upper Tube Sheet Vent South	3

Section 1R18: Plant Modifications

PROCEDURES

NUMBER	TITLE	REVISION
OP-1304.057	Unit 1 Source Range Channels Calibration	20
EN-OP-111	Operational Decision-Making Issue (ODMI) Process	10
OP-1015.037	Post Transient Review	17

WORK ORDERS

00348095	03448996

ENGINEERING CHANGES

43758	43686

CONDITION REPORTS

CR-ANO-1-2012-01134	CR-ANO-1-2012-01683	CR-ANO-1-2012-01852
CR-ANO-1-2013-00217	CR-ANO-1-2013-00551	CR-ANO-1-2013-01010
CR-ANO-1-2013-01012		

MISCELLANEOUS

NUMBER	TITLE	REVISION / DATE
EC 5512	Temporary Modification Evaluation	
	Memo, ANO Unit 1 Gamma-Metrics Source Range Channel Operability Guidance	Oct 11, 2002
STM-67	Systems Training Manual – Nuclear Instrumentation	11

Section 1R19: Post-Maintenance Testing

PROCEDURE

NUMBER	TITLE	REVISION
OP-1412.001	Preventitive Maintenance of Limitorque SB/SMB Motor Operators	37

WORK ORDERS

52403146-01	52366911-01

Section 1R20: Refueling and Other Outage Activities

PROCEDURES

NUMBER	TITLE	REVISION
OP-1504.007	Unit 1 Reactor Vessel Closure Head Removal and Storage	024

Section 1R20: Refueling and Other Outage Activities

PROCEDURES

NUMBER	TITLE	REVISION
OP-1104.004	Decay Heat Removal Operating Procedure	106
OP-1204.043	Refueling Abnormal Operation	8
OP-1502.010	Control of Fuel and Control Rod Movement in Unit 1 Spent Fuel Area	19
OP-1502.003	Refueling Equipment and Operator Checkouts	40
OP-1502.004	Control of Unit 1 Refueling	52
OP-1506.001	Fuel and Control Component Handling	46

Section 1R22: Surveillance Testing

PROCEDURES

NUMBER	TITLE	REVISION
OP-2305.017	Local Leak Rate Testing	29
EN-DC-334	Primary Containment Leak Rate Testing (Appendix J)	1
SEP-APJ-002	ANO Primary Containment Leakage Rate Testing (Appendix J) Program Section	0
OP-2104.037	Alternate ac Diesel Generator Operations	24
OP-1104.036	Emergency Diesel Generator Operation	062
OP-2305.016	Remote Features Periodic Testing	025
OP-2104.036	Emergency Diesel Generator Operations	084
OP-2106.006	Emergency Feedwater System Operations	083

CONDITION REPORTS

CR-ANO-2-2005-1062	CR-ANO-2-2008-0678	CR-ANO-22-11-0800	CR-ANO-2-2011-1194
CR-ANO-2-2012-1789	CR-ANO-2-2012-2270	CR-ANO-2-2012-2846	CR-ANO-C-2013-0310
CR-ANO-C-2013-0331	CR-ANO-C-2013-332	CR-ANO-C-2013-353	CR-ANO-C-2013-0384

MISCELLANEOUS

NUMBER	TITLE	REVISION
NEI-94-01	Industry Guidline for Implementing Performance-Based	2-A

MISCELLANEOUS

NUMBER	TITLE	REVISION
	Option of 10CFR Part 50, Appendix J	

CALCULATIONS

NUMBER	TITLE	REVISION
CALC-82-D-2086-01	Volume of CST T-41B Requiring Tornado Missile Protection	2-A
01-E-0044-01	QCST Level for Required Tech Spec Volume	0
99-E-0013-01	Adequacy of QCST (T41-B) to Supply Steam Generator Inventory for PSA 24-Hour Mission Time	0

Section 4OA1: Performance Indicator Verification

PROCEDURES

NUMBER	TITLE	REVISION
EN-FAP-EP-005	Fleet Administrative Procedure – Emergency Preparedness Indicators	0
EN-LI-114	Performance Indicator Process	6

Section 4OA2: Identification and Resolution of Problems

CONDITION REPORTS

CR-ANO-1-2013-00599	CR-ANO-1-2011-02277	CR-ANO-1-2013-01217
CR-ANO-2-2013-00963	CR-ANO-1-2013-01199	CR-ANO-1-2012-00255
CR-ANO-1-2013-01634	CR-ANO-1-2013-01569	CR-ANO-C-2013-00736

PROCEDURE

NUMBER	TITLE	REVISION
OP-1305.038	Unit 1 Local Leak Rate Testing of Electrical Penetrations	000

WORK ORDER

50233933-01

Section 4OA5: Other Activities

PROCEDURES

NUMBER	TITLE	REVISION
1203.025	Natural Emergencies	40
2203.008	Natural Emergencies	26
CEP-UPT-0100	Underground Piping and Tanks Inspection and Monitoring	2

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION
EC-40635	Fukushima NTTF Rec. 2.3 Seismic and Flooding Walkdown Reports	0
ENTGCORP13-RPT-002 Att. C	Flooding Walkdown Package WP26	
	Buried Pipe and Tank Inspection and Monitoring Program, Long Range Plan	3

SUBJECT: Arkansas Nuclear One Unit 1 – Notification Of Inspection (NRC Inspection Report And Request For Information)

From April 1 to April 12, 2013, reactor inspectors from the Nuclear Regulatory Commission's (NRC) Region IV office will perform the baseline inservice inspection at Arkansas Nuclear One Unit 1, using NRC Inspection Procedure 71111.08, "Inservice Inspection Activities." Experience has shown that this inspection is a resource intensive inspection both for the NRC inspectors and your staff. In order to minimize the impact to your onsite resources and to ensure a productive inspection, we have enclosed a request for documents needed for this inspection. These documents have been divided into two groups. The first group (Section A of the enclosure), due by February 19, 2013, identifies information to be provided prior to the inspection to ensure that the inspectors are adequately prepared. The second group (Section B of the enclosure) identifies the information the inspectors will need upon arrival at the site. It is important that all of these documents are up to date and complete in order to minimize the number of additional documents requested during the preparation and/or the onsite portions of the inspection.

We have discussed the schedule for these inspection activities with your staff and understand that our regulatory contact for this inspection will be Ms. Natalie Mosher of your licensing organization. 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 Jim Drake at (817) 200-1558 (James.Drake@nrc.gov).

This letter does not contain new or amended information collection requirements subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). Existing information collection requirements were approved by the Office of Management and Budget, Control Number 3150-0011. The NRC may not conduct or sponsor, and a person is not required to respond to, a request for information or an information collection requirement unless the requesting document displays a currently valid Office of Management and Budget control number.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room)

INSERVICE INSPECTION DOCUMENT REQUEST

Inspection Dates: April 1 through April 12, 2013

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

Inspectors: Jim Drake, Senior Reactor Inspector (Lead Inspector - ISI)

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 Jim Drake, by March 11, 2013, to facilitate the selection of specific items that will be reviewed during the onsite inspection week. The inspectors will select specific items from the information requested below and then request from your staff additional documents needed during the onsite 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 onsite inspection. If you have any questions regarding this information request, please call the inspector as soon as possible.

A.1 ISI/Welding Programs and Schedule Information

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

i) Nondestructive examinations planned for Class 1 and 2 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) Reactor pressure vessel head examinations planned for the upcoming outage.

iii) Examinations planned for Alloy 82/182/600 components that are not included in the Section XI scope (If applicable).

iv) Examinations planned as part of your boric acid corrosion control program (Mode 3 walkdowns, bolted connection walkdowns, etc.).

v) Welding activities that are scheduled to be completed during the upcoming outage (ASME Class 1, 2, or 3 structures, systems, or components).

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 penetrant, Visual VT-1, VT-2, and VT-3), which have identified relevant conditions on Code Class 1 and 2 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. Also, include in the list the nondestructive examination reports with relevant conditions in the reactor pressure vessel head penetration nozzles that have been accepted for continued service. The list of nondestructive examination reports should include a brief description of the structures, systems, or components where the relevant condition was identified.

d) A list with a brief description (e.g., system, material, pipe size, weld number, and nondestructive examinations performed) of the welds in Code Class 1 and 2 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) Copy of any 10 CFR Part 21 reports applicable to your structures, systems, or 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 noncode repairs in service (e.g., pinhole leaks).

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

A.2 <u>Reactor Pressure Vessel Head</u>

a) Provide the detailed scope of the planned nondestructive examinations of the reactor vessel head which identifies the types of nondestructive examination methods to be used on each specific part of the vessel head to fulfill commitments made in response to NRC Bulletin 2002-02 and NRC Order EA-03-009. Also, include examination scope expansion criteria and planned expansion sample sizes if relevant conditions are identified. (If applicable)

b) A list of the standards and/or requirements that will be used to evaluate indications identified during nondestructive examination of the reactor vessel head (e.g., the specific industry or procedural standards which will be used to evaluate potential leakage and/or flaw indications).

A.3 Boric Acid Corrosion Control Program

a) Copy of the procedures that govern the scope, equipment and implementation of the inspections required to identify boric acid leakage and the procedures for boric acid leakage/corrosion evaluation.

b) Please provide a list of leaks (including Code class of the components) that have been identified since the last refueling outage and associated corrective action documentation. If during the last cycle, the unit was shutdown, please provide documentation of containment walkdown inspections performed as part of the boric acid corrosion control program.

c) Please provide a copy of the most recent self-assessment performed for the boric acid corrosion control program.

A.4 Steam Generator Tube Inspections

a) A detailed schedule of:

   i) Steam generator tube inspection, data analyses, and repair activities for the upcoming outage

   ii) Steam generator secondary side inspection activities for the upcoming outage.

b) Please provide a copy of your steam generator inservice inspection program and plan. Please include a copy of the operational assessment from last outage and a copy of the following documents as they become available:

   i) Degradation assessment

   ii) Condition monitoring assessment

c) If you are planning on modifying your Technical Specifications such that they are consistent with Technical Specification Task Force Traveler TSTF-449, “Steam Generator Tube Integrity,” please provide copies of your correspondence with the NRC regarding deviations from the standard technical specifications.

d) Copy of steam generator history documentation given to vendors performing eddy current testing of the steam generators during the upcoming outage.

e) Copy of steam generator eddy current data analyst guidelines and site validated eddy current technique specification sheets. Additionally, please provide a copy of EPRI Appendix H, “Examination Technique Specification Sheets,” qualification records.

f) Identify and quantify any steam generator tube leakage experienced during the previous operating cycle. Also provide documentation identifying which steam generator was leaking and corrective actions completed or planned for this condition (If applicable).

g) Provide past history of the condition and issues pertaining to the secondary side of the steam generators (including items such as loose parts, fouling, top of tube sheet condition, crud removal amounts, etc.)

h) Provide copies of your most recent self assessments of the steam generator monitoring, loose parts monitoring, and secondary side water chemistry control programs.

i) Indicate where the primary, secondary, and resolution analyses are scheduled to take place.

j) Provide a summary of the scope of the steam generator tube examinations, including examination methods such as Bobbin, Rotating Pancake, or Plus Point, and the percentage of tubes to be examined. <u>Do not provide these documents separately if already included in other information requested.</u>

A.5 <u>Additional Information Related to all Inservice Inspection Activities</u>

a) A list with a brief description of inservice inspection, boric acid corrosion control program, and steam generator tube inspection related issues (e.g., condition reports) entered into your corrective action program since the beginning of the last refueling outage (for Unit 1). For example, a list based upon data base searches using key words related to piping or steam generator tube degradation such as: inservice inspection, ASME Code, Section XI, NDE, cracks, wear, thinning, leakage, rust, corrosion, boric acid, or errors in piping/steam generator tube examinations.

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

Inservice inspection (examination, planning)

Containment exams

Reactor pressure vessel head exams

Snubbers and supports

Repair and replacement program

Licensing

Site welding engineer

Boric acid corrosion control program

Steam generator inspection activities (site lead and vendor contact)

c) Please provide a copy of NDE procedures, the boric acid corrosion control program and related procedures, and the welding program.

B. Information to be Provided Onsite to the Inspector(s) at the Entrance Meeting (April 1, 2013):

B.1 Inservice Inspection / Welding Programs and Schedule Information

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

b) For ASME Code Class 1 and 2 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 weld procedures used to fabricate the welds

vi) Copies of procedure qualification records supporting the weld procedures 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 testing 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 weld procedures (at least 6 months prior to the date of subject work)

xii) Copies of nondestructive examination personnel qualifications (Visual inspection, penetrant testing, ultrasonic testing, radiographic testing), as applicable

c) For the inservice inspection related corrective action issues selected by the inspectors 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 Code Class 1 and 2 systems selected by the inspectors 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 inspectors from section A of this enclosure, provide a copy of the nondestructive examination procedures used to perform the examinations (including calibration and flaw characterization/sizing procedures). For ultrasonic examination procedures qualified in accordance with ASME Section XI, Appendix VIII, provide documentation supporting the procedure qualification (e.g., the EPRI 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.

B.2 <u>Reactor Pressure Vessel Head</u>

a) Provide the nondestructive personnel qualification records for the examiners who will perform examinations of the reactor pressure vessel head.

b) Provide drawings showing the following: (If a visual examination is planned for the upcoming refueling outage)

i) Reactor pressure vessel head and control rod drive mechanism nozzle configurations

ii) Reactor pressure vessel head insulation configuration

Note: The drawings listed above should include fabrication drawings for the nozzle attachment welds as applicable.

c) Copy of nondestructive examination reports from the last reactor pressure vessel head examination.

d) Copy of evaluation or calculation demonstrating that the scope of the visual examination of the upper head will meet the 95 percent minimum coverage required by NRC Order EA-03-009 (If a visual examination is planned for the upcoming refueling outage).

e) Provide a copy of the procedures that will be used to identify the source of any boric acid deposits identified on the reactor pressure vessel head. If no explicit procedures exist which govern this activity, provide a description of the process to be followed including personnel responsibilities and expectations.

f) Provide a copy of the updated calculation of effective degradation years for the reactor pressure vessel head susceptibility ranking.

g) Provide copy of the vendor qualification report(s) that demonstrates the detection capability of the nondestructive examination equipment used for the reactor pressure vessel head examinations. Also, identify any changes in equipment configurations used for the reactor pressure vessel head examinations which differ from that used in the vendor qualification report(s).

B.3 Boric Acid Corrosion Control Program

a) Please provide boric acid walkdown inspection results, an updated list of boric acid leaks identified so far this outage, associated corrective action documentation, and overall status of planned boric acid inspections.

b) Please provide any engineering evaluations completed for boric acid leaks identified since the end of the last refueling outage. Please include a status of corrective actions to repair and/or clean these boric acid leaks. Please identify specifically which known leaks, if any, have remained in service or will remain in service as active leaks.

B.4 Steam Generator Tube Inspections

a) Copies of the Examination Technique Specification Sheets and associated justification for any revisions.

b) Copy of the guidance to be followed if a loose part or foreign material is identified in the steam generators.

c) Please provide a copy of the eddy current testing procedures used to perform the steam generator tube inspections (specifically calibration and flaw characterization/sizing procedures, etc.). Also include documentation for the specific equipment to be used.

d) Please provide copies of your responses to NRC and industry operating experience communications such as Generic Letters, Information Notices, etc. (as applicable to steam generator tube inspections) Do not provide these documents separately if already included in other information requested such as the degradation assessment.

e) List of corrective action documents generated by the vendor and/or site with respect to steam generator inspection activities.

B.5 Codes and Standards

a) Ready access to (i.e., copies provided to the inspector(s) for use during the inspection at the onsite 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) EPRI and industry standards referenced in the procedures used to perform the steam generator tube eddy current examination.

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