



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

June 7, 2013

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

SUBJECT: ARKANSAS NUCLEAR ONE - NRC AUGMENTED INSPECTION TEAM
REPORT 05000313/2013011 AND 05000368/2013011

Dear Mr. Browning:

On May 9, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Arkansas Nuclear One Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed with you and other members of your staff during a public exit meeting conducted on May 9, 2013.

During a refueling outage on March 31, 2013, a temporary overhead crane being used to move the generator stator from Unit 1 collapsed, killing one person and injuring eight others. Unit 1 lost electrical power from offsite sources due to damage caused by the dropped stator, and both emergency diesel generators started and restored power to the Unit 1 safety-related switchgear. Unit 2 was operating at full power and automatically shutdown when the impact of the crane components on the turbine deck caused electrical breakers to open, removing power from one of four operating reactor coolant pumps. Water from a ruptured fire main later caused a short circuit and small explosion inside an electrical breaker cabinet on Unit 2, resulting in the loss of one offsite power source to Unit 2. As a result, one of the Unit 2 emergency diesel generators started and restored power to its associated safety-related switchgear. In response to the small explosion inside the Unit 2 electrical cabinet, operators declared a Notification of Unusual Event, terminating it after taking corrective actions to stabilize the plant's power supplies. There were no radiological releases due to this event.

In accordance with Management Directive 8.3, "NRC Incident Investigation Program," deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. Because two deterministic criteria were met (multiple failures in systems used to mitigate the event and possible adverse generic implications), and based on the estimated conditional core damage probability for the event, Region IV concluded that the NRC response should be an augmented inspection team.

Based on inspection, the team determined that: (1) after the event occurred, the plant safety systems responded as designed, all assumptions in the accident analysis appropriately bounded the event, and no unanalyzed condition existed; and (2) the initial Entergy actions to

restore equipment and to establish a cause evaluation team following the March 31 event were appropriate. The purpose of this inspection was to gather facts and identify issues requiring follow-up, and, as such, no findings were identified. Items requiring additional follow-up are documented as unresolved items in the enclosed report. NRC inspectors separately verified that those equipment issues required to be resolved before plant startup of Unit 2 were adequately resolved. The NRC will conduct additional inspection of the cause evaluation effort and the approach Entergy will use in prioritizing and implementing corrective actions.

This event is also the subject of an investigation by the Occupational Safety and Health Administration (OSHA). Both NRC and OSHA have jurisdiction over occupational safety and health at NRC-licensed facilities. NRC and OSHA have a Memorandum of Understanding in place to ensure a coordinated agency effort in the protection of workers and to avoid duplication of effort. The OSHA investigation is still ongoing.

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,

/KMK for/

Arthur T. Howell III
Regional Administrator

Docket Nos.: 50-313; 50-368
License Nos.: DPR-51; NPF-6

Enclosure: 1. Executive Summary
2. Inspection Report 05000313; 05000368/2013011
w/Attachments:
1. Supplemental Information
2. Sequence of Events
3. Augmented Inspection Team Charter

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EXECUTIVE SUMMARY

An Augmented Inspection Team was chartered on April 5, 2013, to assess the facts and circumstances surrounding the temporary crane failure event resulting in a loss of offsite power for Arkansas Nuclear One Unit 1, a partial loss of offsite power for Unit 2, and a Notification of Unusual Event declaration on March 31, 2013. The temporary crane was being used to move the generator stator from Unit 1 when it collapsed, killing one person and injuring eight others. Unit 1 lost electrical power from offsite sources due to damage caused by the dropped stator, and both emergency diesel generators started and restored power to the Unit 1 safety-related switchgear. Unit 2 was operating at full power and automatically shutdown when hoisting equipment attached to the stator struck the turbine deck and caused electrical breakers to open, removing power from one of four operating reactor coolant pumps. Water from a ruptured fire main later caused a short circuit and small explosion inside an electrical breaker cabinet on Unit 2, resulting in the loss of one offsite power source to Unit 2. As a result, one of the Unit 2 emergency diesel generators started and restored power to its associated safety-related switchgear. In response to the small explosion inside the Unit 2 electrical breaker cabinet, operators declared a Notification of Unusual Event, terminating it after taking corrective actions to stabilize the plant's power supplies.

The augmented inspection team concluded that after the event occurred, the plant safety systems responded as designed, all assumptions in the accident analysis appropriately bounded the event, and no unanalyzed condition existed. The augmented inspection team identified ten unresolved items requiring follow-up inspection to determine the existence and significance of any associated performance deficiencies:

- 1) Control of Temporary Modification Associated with the Temporary Fire Pump
- 2) Damage to Unit 1 and Unit 2 Structures, Systems and Components
- 3) Procedural Controls Associated with Unit 1 Steam Generator Nozzle Dams
- 4) Main Feedwater Regulating Valve Maintenance Practices
- 5) Flood Barrier Effectiveness
- 6) Compensatory Measures for Firewater System Rupture
- 7) Timeliness of Emergency Action Level Declaration
- 8) Effectiveness of Shutdown Risk Management Program
- 9) Effectiveness of Material Handling Program
- 10) Causes and Corrective Actions Associated with the Dropped Heavy Load Event

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket: 05000313; 05000368

License: DPR-51; NPF-6

Report: 05000313/2013011; 05000368/2013011

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 5 through May 9, 2013

Inspectors: G. Miller, Chief, Engineering Branch 2
A. Sanchez, Senior Resident Inspector, Project Branch E
J. Watkins, Reactor Inspector, Engineering Branch 2
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Approved By: Donald B. Allen, Chief, Project Branch E
Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000313; 05000368/2013011; 04/05/2013 – 05/09/2013; Arkansas Nuclear One; Augmented Inspection Team

An Augmented Inspection Team was chartered on April 5, 2013, to assess the facts and circumstances surrounding the temporary crane failure event at Arkansas Nuclear One that occurred on March 31, 2013. The team was established in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program," and the inspection was implemented using Inspection Procedure 93800, "Augmented Inspection Team." The inspection was conducted by a team of inspectors from the NRC's Region IV office and the NRC Office of Nuclear Reactor Regulation (NRR). The team identified ten issues that will require additional NRC inspection. These issues are tracked as unresolved items in this report.

- On April 5, 2013, an Augmented Inspection Team was chartered to assess the facts and circumstances surrounding a temporary crane failure event resulting in a loss of offsite power for Arkansas Nuclear One Unit 1, a partial loss of offsite power for Unit 2, and a Notification of Unusual Event declaration on March 31, 2013. The temporary crane was being used to move the generator stator from Unit 1 when it collapsed, killing one person and injuring eight others. Unit 1 lost electrical power from offsite sources due to damage caused by the dropped stator, and both emergency diesel generators started and restored power to the Unit 1 safety-related switchgear. Unit 2 was operating at full power and automatically shutdown when hoisting equipment attached to the stator struck the turbine deck and caused electrical breakers to open, removing power from one of four operating reactor coolant pumps. Water from a ruptured fire main later caused a short circuit and small explosion inside an electrical breaker cabinet on Unit 2, resulting in the loss of one offsite power source to Unit 2. As a result, one of the Unit 2 emergency diesel generators started and restored power to its associated safety-related switchgear. In response to the small explosion inside the Unit 2 electrical breaker cabinet, operators declared a Notification of Unusual Event, terminating it after taking corrective actions to stabilize the plant's power supplies.

The team determined that after the event occurred, the plant safety systems responded as designed, all assumptions in the accident analysis appropriately bounded the event, and no unanalyzed condition existed. The augmented inspection team identified ten unresolved items requiring follow-up inspection to determine the existence and significance of any associated performance deficiencies.

A. NRC-Identified Findings and Self-Revealing Findings

No findings were identified.

B. Licensee-Identified Violations

None.

REPORT DETAILS

1.0 Event Chronology (Charter Item #1)

The team developed and evaluated a timeline of significant events from the temporary overhead crane failure on March 31, 2013, through the restoration of offsite power and securing of the emergency diesel generators on April 6, 2013. The team developed the timeline, in part, through a review of control room alarm logs; control room operator log entries; parameter plots from the plant computer; and interviews with plant operators, engineers, and maintenance personnel.

1.1 Summary of the Sequence of Events

Prior to the event on March 31, 2013, Arkansas Nuclear One Unit 1 was shutdown in a refueling outage. The reactor vessel head had been removed, fuel was in the reactor vessel, and the refueling cavity was flooded up with water level greater than 23 feet above the reactor vessel flange. Unit 2 was operating at 100 percent power.

At approximately 7:50 a.m. (CDT) on March 31, 2013, while lifting and transferring the Arkansas Nuclear One Unit 1 main generator stator to the train bay, the temporary overhead crane collapsed, causing the 525-ton stator to fall on and extensively damage portions of the turbine deck and subsequently to fall over 30 feet into the train bay. The impact of the stator and crane components on the turbine deck damaged the electrical non-vital buses supplying offsite power to Unit 1 and caused the supply breaker to Unit 2 reactor coolant pump B to open. The damage to the electrical buses resulted in a loss of offsite power to Unit 1, and the trip of reactor coolant pump B resulted in the Unit 2 reactor trip from 100 percent power.

The licensee reported that one worker was killed and eight others were injured when the main generator stator fell.

With the loss of offsite power to Unit 1, both Unit 1 emergency diesel generators started and loaded onto their respective safety-related electrical buses. Operators promptly restored decay heat removal for the reactor coolant system. The Unit 1 emergency diesel generators remained in operation for approximately six days following the event, when offsite power was restored to the safety-related buses.

The collapse of the temporary crane resulted in the rupture of an eight-inch fire main in the turbine building train bay. Water from the fire suppression system migrated to several areas of the turbine building on both the Unit 1 and Unit 2 sides, and leaked through floor hatches in the train bay into the Unit 1 auxiliary building. Operators secured the station fire pumps and isolated the affected piping to stop the leakage of water into the turbine building.

At 9:23 a.m., offsite power to Unit 2 from startup transformer 3 was lost after water from the ruptured fire main caused an electrical fault inside the Unit 2 nonsafety-related switchgear in the turbine building. The loss of power from startup transformer 3 resulted

in a trip of the running reactor coolant pumps and charging pump on Unit 2, and a trip of the running instrument air compressors maintaining instrument air header pressure for both units. Unit 2 emergency diesel generator 2 started and energized the train B vital electrical bus, while the train A vital and non-vital electrical buses were re-energized from startup transformer 2. Operators took appropriate actions to stabilize Unit 2 and restore the instrument air system. Operators subsequently cooled Unit 2 to cold shutdown conditions on natural circulation.

At 10:33 a.m., the licensee declared a Notification of Unusual Event because the electrical fault inside the switchgear appeared to have resulted in a small explosion in the breaker cubicle. The emergency declaration was terminated at 6:21 p.m. after operators confirmed the affected electrical bus was not energized and there was no other damage.

There were no radiological releases due to this event.

A detailed sequence of events is provided in Attachment 2 to this report.

2.0 Evaluation of Operator Actions (Charter Item #2)

a. Inspection Scope

The team conducted an independent review of licensee operator actions taken in response to the event to determine if the actions were appropriate. The inspectors reviewed the immediate actions by the control room staff to stabilize the plant using abnormal and emergency operating procedures and the Unit 2 control room staff actions to cool the plant to cold shutdown conditions.

To assess the overall performance of the operating crews, the inspectors interviewed on-shift personnel and reviewed the post-trip report, which included control room logs, operator statements, and plant data trends. The team assessed operator awareness and decision-making, procedure use and adherence, communications, and command and control. The resident inspection staff provided additional assessment information to the team based on direct control room observations during the event.

b. Observations

The team concluded that the operator actions taken in response to the collapse of the temporary overhead crane and dropped generator stator were appropriate in that all safety system functions were maintained and both reactors were maintained in a safe condition throughout the event. The team identified one unresolved item for additional follow-up inspection involving the control of a temporary modification associated with the temporary fire pump.

.1 Unit 1 Operator Response

On March 31, 2013, Unit 1 was in Mode 5 with reactor coolant system level approximately 23 feet above the reactor vessel flange, and operators were preparing to off load the fuel and begin Green train maintenance. Two trains of decay heat cooling were in service. Offsite power was being supplied from startup transformer 1 through bus A1 to the safety-related Red train bus A3, with bus A2 de-energized. Bus A3 was also cross-connected to the safety-related Green train bus A4. Both emergency diesel generators were operable and in standby. At 7:50 a.m. the temporary crane failed, resulting in dropping the main generator stator. The stator struck the turbine deck from a height of approximately 18 inches, then rolled into the train bay, falling an additional thirty feet before coming to rest on top of the transporter previously staged in the train bay to remove the stator. The force of the stator impact on the turbine deck deformed structural members, which impacted the nonsafety-related bus A2 switchgear one level below the turbine deck. The impact buckled switchgear doors and tripped the supply breakers for bus A1, which resulted in a loss of offsite power to Unit 1.

Following the loss of offsite power, both Unit 1 emergency diesel generators automatically started and connected to the Class 1E 4160 volt buses A3 and A4 as designed. Operators entered the appropriate emergency operating procedure, ensured proper equipment operation, and placed non-vital switchgear feeder breakers in pull-to-lock. The team determined the operator actions in response to the loss of offsite power were appropriate and conducted in accordance with abnormal operating procedure OP-1202.007, "Degraded Power," Revision 12.

The loss of offsite power resulted in the loss of power to both decay heat removal trains. Since the plant was in Mode 6, the decay heat removal pumps were not aligned to automatically restart following the emergency diesel generator starting and connecting to the Class 1E 4160 volt buses. Operators manually restored both decay heat removal trains to regain reactor core cooling. Train A decay heat removal system was restored within six minutes and train B was restored within 16 minutes. Given the volume of water in the reactor coolant system while flooded to greater than 23 feet above the reactor vessel flange and the short duration without decay heat removal capability, there was no appreciable change in reactor coolant temperature. The team determined the operator actions in response to the loss of decay heat removal were appropriate and conducted in accordance with abnormal operating procedure OP-1203.028, "Loss of Decay Heat Removal," Revision 26.

Although not safety-related, the spent fuel pool cooling pumps are powered from safety-related 480 volt buses that were restored when safety-related electrical buses A3 and A4 were re-energized from the emergency diesel generators. Operators responded to the loss of spent fuel pool cooling by manually starting spent fuel pool cooling pump P-40B at 8:13 a.m. Operators placed intermediate cooling water pump P-33C for the spent fuel pool into service at 9:30 a.m. via a pre-planned temporary modification that restored nonsafety-related power to the pump. Operators secured the pump five minutes later following a loss of instrument air pressure caused by a partial loss of offsite power on Unit 2. Operators restarted the pump at 10:31 a.m. after instrument air pressure was restored. The spent fuel pool temperature rose approximately 3 degrees Fahrenheit

over a three hour period, to a peak of 89.8 degrees Fahrenheit. The team determined the operator actions in response to the loss of spent fuel pool cooling were appropriate and conducted in accordance with abnormal operating procedure OP-1203.050, "Unit 1 Spent Fuel Pool Emergencies," Revision 5.

The loss of power to the instrument air compressors also affected the decay heat cooler bypass valves and the intermediate cooling water cross-connect valves, both of which closed on the loss of instrument air pressure. Operators aligned the train A decay heat removal system with the cooler bypass valve fully closed and restored it to service. The loss of instrument air was reviewed by operators and appropriate action was taken to mitigate the effects in accordance with abnormal operating procedure OP-1203.024, "Loss of Instrument Air," Revision 13.

.2 Unit 2 Operator Response

On March 31, 2013, Unit 2 was operating in Mode 1 at 100 percent power and no technical specification shutdown action statements were in effect. When the temporary crane collapsed and the stator dropped at 7:50 a.m., the vibration resulted in a relay actuation associated with the B reactor coolant pump breaker which tripped the breaker. The core protection calculator initiated a reactor trip due to loss of reactor coolant system flow. Following the reactor trip main feedwater regulating valve A failed to indicate fully closed as designed.

The inspectors determined the Unit 2 control room operators responded appropriately to the reactor trip. Operators responded to the apparent failure of main feedwater regulating control valve A to fully close by tripping main feedwater pump A and initiating the emergency feedwater actuation system. Operators later manually secured emergency feedwater to feed steam generators using auxiliary feedwater through the emergency feedwater injection motor operated valves, which required rendering both emergency feedwater pumps inoperable and entry into Technical Specification 3.0.3. An unresolved item associated with the apparent failure of the main feedwater regulating valve is discussed in Section 4.0 of this report.

At approximately 9:23 a.m., water from the ruptured fire main in the train bay leaked into the breaker cubicle for breaker 2A-113 (supply breaker from startup transformer 3 to bus 2A1). The water intrusion caused phase-to-phase and phase-to-ground faults inside the breaker cubicle. Protective relaying functioned as designed and resulted in a lock out of startup transformer 3. Bus 2A1 fast transferred to startup transformer 2, and emergency diesel generator 2K-4B started and restored power to safety-related bus 2A4. These events resulted in the loss of power to spent fuel pool cooling pump 2P-40B, the instrument air compressors, and caused a trip of the running reactor coolant pumps and charging pump. Operators subsequently declared a Notification of Unusual Event at 10:33 a.m. based on the potential for an explosion having occurred in the breaker cubicle. An unresolved item associated with the emergency declaration is discussed in Section 6.0 of this report.

At the time of startup transformer 3 lock out, spent fuel pool cooling pump 2P-40B was in service. The loss of power to bus 2A2 (and subsequently bus 2B2) caused

pump 2P-40B to trip. Operators appropriately identified the pump trip and placed spent fuel pool cooling pump 2P-40A in service at 10:15 a.m. with no documented temperature rise in the spent fuel pool. The team concluded the operator actions were appropriate.

Operators restarted instrument air compressor A following the loss of instrument air pressure. This provided approximately 45 psi to the instrument air header. At this point, operators reported loud water hammer between feedwater heaters 2E-5B and 2E-B6 on Unit 2 from operation at reduced air pressure. Operators then cross-tied buses 2B1 and 2B2 and restarted instrument air compressor B, which restored instrument air pressure to 90 psi. This was accomplished at approximately 11:40 a.m. The team determined the operators responded appropriately.

The lock out of startup transformer 3 also resulted in the trip of the running charging pump and all running reactor coolant pumps. The concurrent loss of instrument air header pressure caused letdown to be isolated, a loss of normal pressurizer spray, and the loss of the steam dump bypass control system. This complicated the response by resulting in a rapid rise in reactor coolant system pressure. Operators established auxiliary spray and secured pressurizer heaters to reduce reactor coolant system pressure and avoided lifting pressurizer code safety valves. The operators subsequently entered the appropriate abnormal operating procedure and commenced a reactor cool down at 20 to 30 degrees per hour until the plant could be placed onto shutdown cooling. The reactor temperature was reduced to less than 300 degrees without incident. This was the first time operators on Unit 2 had performed this evolution outside the simulator. The team determined the operators responded to the condition in an appropriate manner.

.3 Control of Temporary Modification Associated with the Temporary Fire Pump

Introduction. The team identified an unresolved item associated with operator control of the water supply to the station fire suppression system. Specifically, the team determined additional inspection was needed to assess the timeliness of the licensee's actions to secure the fire pumps and terminate the supply of water to the fire main rupture in the turbine building train bay.

Description. The licensee placed an additional electric motor-driven fire pump in service as a temporary modification for the Unit 1 refueling outage. The power supply for this electric fire pump was from the London 13.8 kV line, which is an additional offsite power source not included in the plant Technical Specifications. At the time of the event, the temporary electric fire pump was in service and supplying water from the intake canal to the station fire suppression system.

Following the collapse of the temporary overhead crane and the drop of the generator stator, an eight-inch fire main in the train bay ruptured. As designed, the diesel-driven fire pump started when the system pressure dropped below 95 psig. The permanently installed electric fire pump was not available due to the loss of offsite power, but the temporary electric fire pump continued to operate since the London 13.8 kV line was unaffected by the event. The two operating pumps were each capable of supplying approximately 2,500 gallons per minute at rated system pressure.

At 8:03 a.m., an entry in the control room log stated that all firewater pumps, including the temporary firewater pump were secured. Several subsequent log entries reflected significant water leakage from the fire suppression system in the turbine building and into the Unit 1 auxiliary building. A log entry entered 67 minutes after the event stated that fire hydrant 1 was cycled opened then shut in an attempt to lower fire header pressure and slow leakage into the train bay. An entry five minutes later stated that the temporary fire pump was secured. An unresolved item associated with the leakage of water past the seals in the turbine building hatches and into the auxiliary building is discussed in Section 4.0 of this report.

The team confirmed through interviews with the operators that the diesel-driven pump was secured first, and the temporary pump was secured at a later time following the cycling of fire hydrant 1. The team reviewed video taken inside the turbine building following the event and confirmed that the diesel-driven pump was secured at a time consistent with the entry in the station log. The team also identified indications of system pressure consistent with an operating pump approximately 40 minutes after the event.

The team concluded that additional inspection was needed to assess the licensee's control of the temporary fire pump modification in regard to the timeliness of securing the temporary electric fire pump following the event: Unresolved Item URI 05000313/2013011-01; 05000368/2013011-01, "Control of Temporary Modification Associated with the Temporary Fire Pump."

3.0 Assess Equipment Impact from Event (Charter Item #3)

a. Inspection Scope

The team conducted a review of the licensee efforts to identify the structural damage to both Unit 1 and Unit 2 structures, systems and components, including damage to personnel access and egress paths. As part of this assessment, the team performed independent physical inspections of accessible affected areas; reviewed condition reports, work orders, and photographs of the damaged areas; and reviewed seismic recordings of the event; and reviewed the licensee's plans for inspection and repair of the affected areas.

b. Observations

The team concluded that the licensee had appropriate plans in place to identify affected equipment, control access to the affected areas, and commence debris removal and repair activities. The team identified one unresolved item requiring follow-up inspection associated with the equipment impact to Unit 1 and Unit 2 from the dropped stator event.

Introduction. The team identified an unresolved item associated with additional inspection of the structures, systems and components in both Unit 1 and Unit 2 after debris removal is complete.

Description. The team observed damage to both Unit 1 and Unit 2 involving fire barriers, fire doors, fire penetrations, fire suppression water piping, fire suppression carbon dioxide piping, instrument air piping, hydrogen piping, flood barriers, ventilation ducting, structural members, electrical cabinets and electrical buswork. The licensee's assessment of damage was still in progress at the conclusion of the inspection.

The licensee performed the following inspections:

- Visually inspected the walls, floors, structural supports, and ceilings of the accessible areas.
- Visually inspected the accessible electrical, mechanical, and fire protection equipment for obvious misalignment or damage.
- Performed resistance tests on various pieces of affected electrical equipment.
- Retrieved and analyzed the recordings of the 6 seismic monitoring stations.

The licensee entered numerous condition reports in their corrective action program concerning damage to walls, floors, ceilings, structural support beams, doors, conduit, cable tray, pipe supports, insulation, anchor bolts, flood barriers, ventilation ducting, fire doors, fire barriers, hydrogen piping, instrument air piping, carbon dioxide piping, electrical cabinets and buswork, mechanical equipment, fire water piping and equipment in the affected areas of both Unit 1 and Unit 2 structures. Due to the volume of condition reports written for both units identifying damage, the licensee initiated summary condition reports for the individual units. The summary condition reports for Unit 1 and Unit 2 are CR-ANO-1-2013-00868 and CR-ANO-2-2013-00620, respectively.

Since full assessment of the equipment impact is not possible until debris removal activities are completed, this item is unresolved pending further evaluation of the structural and equipment damage caused by the dropping of the Unit 1 stator. This issue is identified as URI 05000313/2013011-002; 05000368/2013011-002, "Damage to Unit 1 and Unit 2 Structures, Systems and Components."

4.0 Plant Response (Charter Item #4)

a. Inspection Scope

The team conducted a review of the plant systems response to the temporary crane collapse and compared that response to the safety analyses. As part of their review, the team evaluated the electrical alignment of the Unit 1 vital buses, the seismic monitoring equipment response, and the design and response of the Unit 2 electrical switchgear. The team performed physical inspections of the accessible affected areas, reviewed condition reports, work orders, and photographs of the damaged areas, and reviewed the licensee's seismic recordings of the event.

b. Observations

The team determined that the plant equipment overall responded as expected and as designed in both Unit 1 and Unit 2; however, the team identified three unresolved items associated with the Unit 1 steam generator nozzle dams, Unit 2 main feedwater regulating valve maintenance, and turbine building flood barrier effectiveness.

At the time of the event, Unit 1 was shutdown, and operators were in the process of performing electrical alignments to support the Green train planned maintenance outage. This resulted in the following initial conditions:

- 6900 Volt bus H1 was energized and bus H2 was de-energized.
- 4160 Volt bus A2 was de-energized.
- Safety-related 4160 Volt buses A3 and A4 were cross-tied with power supplied via non-safety related 4160 Volt bus A1.
- 480 Volt buses B5 and B6 were cross-tied.
- Green train battery D06 was disconnected from bus D02.
- Battery charger D04 supplied from swing motor control center B56 to provide power to Green train DC bus D02.
- Motor control center B56 was aligned to bus B5.

At the time of the stator impact, the lights in the Unit 1 side of the turbine building went out due to the loss of power to 4160 Volt bus A1. The team confirmed buses A1, A3, A4, B5 and B6 all lost power. The licensee determined the preliminary cause of the loss of power was due to the activation of protective relays following the stator impact with the turbine building floor directly above the electrical equipment room. This was confirmed by observation of numerous relays in the bus A1 and A2 equipment with no indication of actual fault currents. Upon loss of the supply power bus A1, and with bus A2 already de-energized, Unit 1 experienced a loss of offsite power. The cross-tied safety-related buses A3 and A4 automatically separated from one another upon undervoltage, and both emergency diesel generators automatically started to restore power to the safety-related buses. The emergency diesel generators remained in service for approximately 140 hours following the event. Bus H1 did not trip during the event, but was manually tripped by operators in accordance with procedure approximately 13 minutes after the event. All non-safety related loads lost power during the event.

At the time of the event Unit 2 was at 100% power with normal equipment alignments. When the temporary crane collapsed, parts of the lifting device supporting the Unit 1 stator impacted the Unit 2 turbine deck. The area of the impact was directly above and adjacent to the Unit 2 non-safety related switchgear room containing electrical equipment for buses 2A1, 2A2, 2H1, 2H2, and the alternate AC emergency generator. Coincident with the impact, the breakers supplying power to Unit 2 reactor coolant

pump B and circulating water pump B tripped. The trip of the reactor coolant pump generated a loss of flow signal and resulted in a turbine trip and reactor trip of Unit 2.

The licensee attributed the preliminary apparent cause of the Unit 2 trip to the vibration-induced tripping of reactor coolant pump B as a result of part of the lifting device impacting the Unit 2 turbine floor. The heavy load impact to the Unit 2 turbine building structure caused vibration-induced relay activation. The vibration-induced relay activation is a documented phenomenon at Arkansas Nuclear One that specifically involves Westinghouse Type ITH instantaneous over-current relays used as a motor differential relay. Operating history at Arkansas Nuclear One has demonstrated that this type of relay can be sensitive to vibration. The licensee initiated condition report CR-ANO-2-2013-00583 in the corrective action program to document the conditions and actions associated with the trip of Unit 2 reactor on March 31, 2013.

Circulating water pump 2P-3A also had dropped flags on its relays, but was confirmed to have not tripped by review of plant flow trends during the event. The licensee initiated condition report CR-ANO-2-2013-00606 to review the performance of the breaker flags on circulating water pump A.

Water infiltration into the Unit 2 switchgear room from the ruptured fire water piping caused a bus fault in the 2-A113 breaker approximately one and one half hours after the crane failure event. Protective relaying functioned as designed to isolate the fault, resulting in a startup transformer 3 bus lockout.

.1 Procedural Control Associated with Unit 1 Steam Generator Nozzle Dams

Introduction. The team identified an unresolved item associated with the procedural controls for the backup air supply systems to the Unit 1 nozzle dams.

Description. On March 28, 2013, all Unit 1 steam generator nozzle dams were installed. The nozzle dams consisted of one rigid plug and two inflatable dams, and are installed in the reactor coolant system hot leg and cold leg piping to provide access for work inside the steam generators while maintaining water inventory in the reactor coolant system. The inflatable dams are supplied by either air or nitrogen at a normal operating pressure of 75 psig. On a loss of seal pressure, the design of the nozzle dams limits the maximum leakage through the seals to two gallons per minute. The licensee normally regulates a 90 psig primary supply with an 80 psig backup pressure source. These supplies are procedurally controlled to be independent. At the time of the crane collapse and stator drop event, the primary supply for the nozzle dams was a local electric air compressor with the backup supply provided by a second electric air compressor with a different offsite power source. A contingency plan should both supplies fail was to use the instrument air system.

The event resulted in the loss of offsite electrical power to Unit 1. Most power to the containment building, including power to both air compressors, was lost. Without an air supply, the nozzle dams began to lose pressure. At approximately 9:30 a.m., the contractor for the nozzle dams and the steam generator engineer entered containment and observed dam pressure at 50 psig and falling. The engineer requested nitrogen

bottles be brought into containment. While waiting for the bottles, nozzle dam pressures approached 25 psig, at which point they were subject to reactor coolant system leakage. The engineer connected the local instrument air line, but instrument air pressure was reduced to approximately 50 psig due to the trip of the instrument air compressors following the startup transformer 3 lockout and partial loss of offsite power to Unit 2. The nitrogen bottles subsequently arrived and were placed into service to restore normal operating pressure to the nozzle dam seals.

The licensee subsequently connected a line to the nozzle dams from a distribution air center supplied by the refueling air compressor. The refueling air compressor was located outside the containment building and was powered from the 13.8 kV London line, which was not affected by the stator drop event. The refueling air compressor was placed into service as the primary source of nozzle dam seal pressurization with the nitrogen bottles as the backup source, and the licensee established local nozzle dam checks on a two-hour frequency.

The inspectors determined that procedure OP-5120.504, "OTSG Nozzle-Dam Training, Testing & Installation/Removal," Revision 6, controlled nozzle dam air supplies and identified nitrogen bottles as a backup source; however, the procedure had been revised in 2010 to allow other combinations of air supplies. Nitrogen bottles were not used after the revision for the operational convenience of not bringing the bottles into containment.

The team concluded that additional inspection was required to assess the procedural controls associated with the primary and backup pressure sources for the steam generator nozzle dams. This issue is identified as Unresolved Item URI 05000313/2013011-03, "Procedural Controls Associated with Unit 1 Steam Generator Nozzle Dams."

.2 Main Feedwater Regulating Valve Maintenance Practices

Introduction. The team identified an unresolved item associated with the licensee maintenance practices involving the main feedwater regulating valves.

Description. On August 8, 2012, Unit 2 tripped following a loss of condenser vacuum. Following the trip, main feedwater regulating valve A failed to close and remained approximately 8 percent open, complicating the operator response to the event. The licensee concluded that the valve jacking mechanism had been left in the wrong position following maintenance. An NRC finding associated with this event is documented in NRC inspection report 05000313/2012005; 0500368/2012005 as FIN 05000368/2012005-008 (ADAMS Accession No. ML13045A520).

Following the Unit 2 reactor trip on March 31, 2013, operators identified that main feedwater regulating valve A failed to indicate closed. This indication caused the operators to trip main feedwater pump A and manually initiate the emergency feedwater actuation system. Arkansas Nuclear One Unit 2 is a Combustion Engineering designed plant and emergency feedwater is not normally actuated on a non-complicated reactor trip. Operators subsequently placed the auxiliary feedwater system in service, which required operators to manually inhibit the emergency feedwater system, rendering both

trains inoperable and requiring entry into Technical Specification 3.0.3 for a short period of time. This again complicated operator response to the trip.

The licensee later determined that the regulating valve actually had closed, and the valve indication was in error. The condition was corrected by tightening loose adjustment screws on the valve position indication limit switches.

The team concluded that additional inspection was required to assess the effectiveness of the licensee maintenance practices on the main feedwater regulating valves: Unresolved Item URI 05000368/2013011-04, "Main Feedwater Regulating Valve Maintenance Practices."

.3 Flood Barrier Effectiveness

Introduction. The team identified an unresolved item associated with the effectiveness of flood barriers installed in the turbine building train bay.

Description. On March 31, 2013, a significant fire water leak was created inside the turbine building train bay from a ruptured eight-inch fire header. At 8:30 a.m. Unit 1 operators documented auxiliary building sump water level rise due to firewater leaking into the auxiliary building. The water from the firewater system leaked past the flood barriers installed in hatches in the train bay and filled the building sump, eventually accumulating on the 317-foot elevation of the Unit 1 auxiliary building. The loss of offsite power prevented the auxiliary building sump pumps from operating.

At approximately 11:42 a.m., Unit 1 operations staff noted that approximately one inch of water had accumulated in decay heat vault B located on the 317-foot elevation of the auxiliary building. Water entered the decay heat vault through a leaking room drain isolation valve, ABS-13, located in the auxiliary sump area. The water accumulation in the vault reached a maximum of approximately one-inch and did not affect any emergency core cooling equipment in that room. The water rise in the auxiliary building stopped when operators secured the fire water system. The licensee deployed temporary air-driven sump pumps to the 317-foot elevation of the Unit 1 auxiliary building to remove the accumulated water.

The team concluded that additional inspection was required to determine the causes and impact of the failed flood hatches and the decay heat vault B room drain isolation valve: Unresolved Item URI 05000313/2013011-05, "Flood Barrier Effectiveness."

5.0 Adequacy of Compensatory Measures (Charter Item #5)

a. Inspection Scope

The team reviewed the impact of the temporary overhead crane collapse and stator drop on the fire detection and suppression systems and assessed the licensee's compensatory measures following the event. The compensatory measures assessed included required operator and security actions for damaged equipment and barriers.

The team reviewed control room log entries and condition reports to identify equipment issues. The team also interviewed operations staff, system engineers and security personnel to understand the compensatory measures taken and to assess whether the timeliness of those actions was commensurate with plant conditions.

b. Observations

The team determined that the licensee's compensatory actions were appropriate and preserved plant safety; however, the team also identified one unresolved item for additional follow-up inspection involving the licensee's compensatory measures associated with the firewater system following the fire main rupture in the train bay.

The loss of electrical power for Unit 1 resulted in loss of most non safety-related loads that supplied power to air conditioning, sump and transfer pumps, intermediate cooling water pumps, instrument air compressors, air compressors for steam generator nozzle dams, normal lighting, and the non-vital air compressors that charge emergency diesel generator starting air bank pressures.

The loss of normal air cooling chillers and fans required compensatory measures involving the opening of fire doors and additional compensatory measures for the degraded fire barriers. The team concluded the operator actions to compensate for the loss of cooling and degraded fire barriers were appropriate.

Following the event, the Unit 1 emergency diesel generators were in operation for approximately six days. During this time, the air compressors for the air start system were not available. The licensee implemented appropriate compensatory measures to pressurize the air start system via nitrogen bottles and maintain air start capability if the diesels were to shutdown and needed to be restarted.

The team determined the security compensatory measures implemented by the licensee were appropriate and timely.

Compensatory Measures for Firewater System Rupture

Introduction. The team identified an unresolved item associated with the licensee's compensatory measures for fire suppression prior to the restoration of the damaged firewater system.

Description. The crane collapse and the stator drop in the train bay ruptured an eight-inch diameter fire main in the turbine building. Operators secured the station fire pumps to stop the water flow into the turbine building, resulting in the complete unavailability of the firewater system. As compensatory measures, the licensee positioned a fire pumper truck on one side of the plant and staged three diesel-driven pumps inside the protected area. Through onsite interviews, the team determined that the pumper truck carried approximately one thousand gallons of water, and two of the three diesel-driven firewater pumps had no viable suction sources. The team determined the readily available fire hoses for the one diesel-driven pump with an

available water source may not have been sufficient to provide adequate fire fighting capabilities inside the power block of either unit.

The licensee isolated the ruptured fire main and restored the firewater system to service on the morning of April 1, 2013. The team identified that the Operations staff was largely unaware of the limited capability of the compensatory measures implemented during the period of time the firewater system was unavailable.

The team concluded that additional inspection was needed to fully assess the effectiveness of the compensatory measures and the timeliness of the firewater system restoration: Unresolved Item URI 05000313; 368/2013011-06, "Compensatory Measures for Firewater System Rupture."

6.0 Event Classification and Reporting (Charter Item #6)

a. Inspection Scope

The team conducted an independent review of licensee actions associated with emergency event classification and reporting. To assess the licensee's actions in this area, the team performed a detailed review of operator logs, the computerized sequence of events and condition reports. The team also conducted interviews with operators and emergency preparedness personnel

b. Observations

The team concluded the declaration of a Notification of Unusual Event in accordance with Emergency Action Level HU4 for a small explosion inside the protected area was appropriate. The team identified one unresolved item requiring additional inspection related to the timeliness of the emergency declaration.

Introduction. The team identified an unresolved item involving the timeliness of the emergency declaration of a Notification of Unusual Event based on the information available to the control room operators.

Description. At approximately 9:23 a.m. on March 31, 2013, Unit 2 experienced a startup transformer 3 lockout due to an electrical fault inside the breaker cabinet for startup transformer 3 to bus 2A1 supply breaker 2A-113. Initial reports to the control room indicated that the door of the feeder breaker appeared to be blown open, and light smoke was observed in the area. This information was documented in the control room logs at 9:25 a.m. Through interviews with responding operators, the team determined that this information was separately reported to the control room multiple times and by different methods. At some time later, another operator looked into the panel and identified damage to the bus bars inside the breaker cabinet. Although not documented in the control room logs, this information was reported to the control room at approximately 10:20 a.m. Operators subsequently declared a Notification of Unusual Event based on a small explosion inside the protected area (HU4) at 10:33 a.m.

The team determined that multiple reports had been made to the control room, but the information appeared to be substantially the same as the initial report received at 9:25 a.m. The 9:25 a.m. report was also the only report documented in the control room logs. The team concluded that additional follow-up inspection was required to assess the timeliness of the emergency classification given the information available to the control room operators: Unresolved Item URI 05000368/2013011-07, "Timeliness of Emergency Action Level Determination."

7.0 Heavy Lift Preparations and Associated Risk Assessment (Charter Item #7)

a. Inspection Scope

The team assessed the adequacy of the licensee's preparations for the heavy lift. This assessment included evaluation of licensee procedure use and adequacy associated with the oversight of contractors, the risk management activities associated with Unit 1 during the refueling outage, and risk management associated with Unit 2 during operation at full power. The team also evaluated the risk management administrative controls applicable to operating and shutdown units.

b. Observations

The team identified two items for additional follow-up inspection associated with this charter item.

.1 Shutdown Risk Management

Introduction. The team identified an unresolved item associated with the licensee's implementation of shutdown reactor risk management actions.

Description. The team reviewed procedure EN-OU-108, "Shutdown Safety Management Program," Revision 5, which provided a process to assess the overall impact of plant maintenance on plant risk to satisfy the requirements of 10 CFR 50.65(a)(4) during the cold shutdown and refueling modes of reactor operation. Step 5.4, "Conducting the Shutdown Safety Assessment," specified that the Outage Risk Assessment Team be assembled and evaluate the outage schedule, including identification of higher risk evolutions.

The team reviewed Condition Report CR-ANO-1-2013-00132, initiated on January 28, 2013, which documented the Outage Risk Assessment Team review of Revision 0 of the Unit 1 Outage schedule. This review identified a table of specific outage items and included an additional comment questioning whether contingency plans were needed for three planned outage activities, including "flying the stator on the turbine deck." The resolution of the additional comment identified that the outage management organization determined no contingency plans were necessary for the stator movement.

Through interviews with the licensee staff, the team determined that the outage management organization considered the likelihood of a problem with the stator movement to be very low and considered that no practical contingency measures were

necessary beyond a temporary modification to provide alternate power to one non-safety intermediate cooling water pump. This determination was based on Unit 1 being scheduled to be in the refueling mode of operation with water level high above the reactor vessel flange. The intermediate cooling water pump normally receives power from non-safety related bus A2, and the system provides cooling water to the spent fuel pool cooling heat exchangers. The temporary modification to supply power to one pump from an alternate offsite source allowed operation of adequate intermediate cooling water system capacity throughout the planned outage of the Green train equipment, including the outage of nonsafety-related bus A2. The temporary modification to provide power to the intermediate cooling water pump was prepared but was not installed prior to beginning the stator lift.

For identified higher risk evolutions or conditions, procedure EN-OU-108 specified the use of guidance in procedure Attachment 9.1, "Qualitative Risk Evaluation and Risk Mitigation Plan," to assess the impact of higher risk evolutions or conditions on key safety functions. Sheet 4 of 5 in Attachment 9.1 provided a checklist of contingency measures for heavy load lifts. A note contained on the heavy load lift checklist identified that specific compensatory risk management actions were contained in procedure EN-MA-119, "Material Handling Program," Revision 16. The checklist included additional contingency measures for heavy load lifts when equipment under the load path is protected. In the plant state at the time of the event (Shutdown Condition 2: reactor vessel head removed, reactor cavity flooded to greater than 23 feet above the reactor vessel flange, fuel in the reactor vessel, and no fuel movement in progress), the Shutdown Operations Protection Plan (Procedure 1015.048, Revision 9) specified that at least one of the offsite power sources be operable. However, all available offsite power sources passed beneath the load path. Furthermore, Technical Specification Limiting Condition for Operation 3.8.2, "AC Sources – Shutdown," required one offsite source of power be operable in operating modes 5 and 6, and during movement of irradiated fuel assemblies. Therefore, the team determined that at least one offsite power source must be protected in that mode of operation. At the time of the stator movement the non-safety related bus A2 was removed from service and safety-related buses A3 and A4 were cross-tied and receiving power from the Unit 1 startup transformer offsite source via non-safety bus A1. Therefore, the only operable offsite power source was under the load path for the stator movement.

The heavy load handling checklist in Attachment 9.1 to procedure EN-MA-119 included the following possible risk mitigation actions for the protected equipment:

- Enhance communication to improve awareness of the load lift and its relation to maintenance activities.
- Revise load path.
- Add compensatory actions or back-up safety functions to enhance safety function redundancy.

- Assume safety function is impacted by potential load drop and adjust the key safety function assessment accordingly.

Of these actions, the licensee enhanced communication by treating the heavy lift of the stator as an infrequently performed test or evolution (IPTE); and the plant staff prepared a temporary modification to provide an alternate power source to one of the intermediate cooling water pumps if needed.

The team evaluated the effectiveness of the implemented measures in managing the effect of a potential heavy load drop on protected electrical equipment. The team reviewed the IPTE briefing materials and the outage schedule to assess how the relationship between the stator movement and other outage activities was controlled. The team found that the briefing materials provided direction related to industrial safety, but the materials did not provide documented restrictions during the heavy load lift related to reactor plant conditions or the availability of equipment for maintenance of key safety functions, such as reactor decay heat removal, reactor makeup water, and electrical power. Interviews with outage management and operating staff personnel indicated that no firm relationships had been established between the stator movement and other refueling outage activities. Through review of the outage schedule, the team identified cases of potentially elevated plant risk during the planned stator movement. For example, the team determined that the planned sequence of stator movements called for positioning the replacement stator in the turbine building at a time when the entire Green train electrical distribution was scheduled to be out of service, including the ability to use one of the two installed safety-related emergency diesel generators and one of two safety-related station batteries. In addition, the outage schedule indicated fuel transfer to the spent fuel pool would be in progress.

Based on the absence of administrative controls addressing the relationship between the stator replacement activities and other outage activities related to reactor key safety functions, the team concluded that additional inspection was needed to assess the effectiveness of the plant risk mitigating measures associated with the stator movement activities: Unresolved Item URI 05000313/2013011-08, "Effectiveness of Shutdown Risk Management Program."

.2 Material Handling Risk Management

Introduction. The team identified an unresolved item associated with the licensee's implementation of Procedure EN-MA-119, "Material Handling Program."

Description. The team evaluated the effectiveness of contingency measures to reduce the potential for a load drop. The team determined through interviews that the project management organization considered the temporary overhead crane to be a temporary hoisting assembly. Section 5.2, "Load Handling Equipment Requirements," of Procedure EN-MA-119, Item [7], "Temporary Hoisting Assemblies," specified the following measures to establish hoist integrity:

- Licensee engineering support personnel shall approve the design of vendor-supplied temporary overhead cranes.
- The temporary overhead crane shall be designed for 125 percent of the projected hook load and shall be load tested in all configurations for which it will be used.
- Load bearing welds shall be inspected before and after the load test.

However, Item [7] also included a note specifying that specially designed lifting devices may be designed and tested to other approved standards.

Through interviews with licensee staff, the team determined that the focus of the evaluations the licensee performed was to ensure the temporary overhead crane did not overload the existing plant structures. The licensee also identified that the temporary crane had not been load tested. Although the note in procedure EN-MA-119 allowed the use of alternate standards in lieu of load testing, the licensee could not provide the team with an alternate approved standard for the design and testing of the temporary overhead crane assembly.

The team reviewed Calculation 27619-C1, "Heavy Lift Gantry Calculation – ANO Stator Replacement Project," Revision 0, which evaluated the structure of the temporary overhead crane. This calculation was completed by a contractor performing the stator replacement for the licensee. The calculation identified the American Institute of Steel Construction (AISC) Steel Construction Manual, 14th Edition, and the American Society of Mechanical Engineers (ASME) standard NQA-1, "Quality Assurance Requirements for Nuclear Facility Applications," as references. The AISC Steel Construction Manual provided standard methods of evaluating acceptable loadings for beams and columns constructed from standard steel shapes. The ASME NQA-1 standard provided guidance for implementing an acceptable quality assurance program at nuclear power plants during siting, design, construction, operation, and decommissioning. Subpart 2.15, "Quality Assurance Requirements for Hoisting, Rigging, and Transporting of Items for Nuclear Power Plants," provided standards for the design, manufacture, acceptance, testing, and use of hoisting, rigging, and transporting equipment to maintain the quality of designated nuclear power plant items that require special handling.

The inspection team reviewed the conformance of the design and testing of the temporary overhead crane to criteria contained in Subpart 2.15 of standard NQA-1. The standard recognized that control over the handling of an item is dependent on the importance of the item to safe, reliable operation of the plant and the complexity of the operation. Subpart 2.15 of NQA-1 established the following three categories of items to establish criteria for handling of these items:

- Category A items need specially selected handling equipment and detailed handling procedures because of large size and weight.
- Category B items may be handled with conventional equipment but need detailed handling procedures because of the item's susceptibility to damage
- Category C items may be handled with conventional equipment using sound rigging practices (i.e., the item is neither large in size and weight nor susceptible to damage).

The team determined that the stator corresponded to a Category A item because it was large in size and weight and comparable in these parameters to examples of Category A items provided in the standard. For Category A items, the standard provided specific design, acceptance, and testing criteria applicable to special design handling equipment, including items such as special crane support runways, columns, and frames, which were the subject of Calculation 27619-C1.

The team reviewed implementation of the design, acceptance criteria, and testing specified in Subpart 2.15 of NQA-1 in the design of the temporary overhead crane. The team identified discrepancies between the design criteria specified in Section 400 of Subpart 2.15 of standard NQA-1 and the design evaluation completed in Calculation 27619-C1, including an assumption of transverse frame loading that was less than two percent of the handled load and the absence of evaluations considering the design of column end fittings. Also, as noted above, the temporary overhead crane structure was not subjected to a load test as specified in Section 601 of Subpart 2.15 of standard NQA-1. The team noted that recognition of adequate capability by a qualified engineer was identified in Section 503.2(e) of Subpart 2.15 as an acceptable alternative to these design and test acceptance criteria for equipment used to handle only Category C items. The team did not have access to the contractor staff that completed the calculation to discuss the application of the standard.

The team determined that the design and test process applied to the crane did not conform to applicable procedures and standards. However, the root cause of the stator temporary overhead crane failure had not been established at the time of this team inspection (URI 05000313/2013011-10 in Section 8.0 of this report) and alternate acceptable standards with different acceptance criteria may be identified. Therefore, the team concluded that additional inspection was needed to assess the effectiveness of the material handling program implementation in mitigating risk associated with the stator movement activities: Unresolved Item URI 05000313/2013011-09, "Effectiveness of Material Handling Program."

.3 Operating Reactor Risk Management

The team reviewed procedure COPD-024, "Risk Assessment Guidelines," Revision 44, effective January 22, 2013, which provided administrative controls for risk management in operational modes 1 through 4 (i.e., power operation through hot shutdown). Through interviews with the Unit 2 Operations staff, the team determined that the operations staff was aware of the timing of the proposed stator move and had determined the stator

movement was unlikely to affect Unit 2 operations because plant equipment was not directly under the proposed stator movement path. Although the crane collapse affected Unit 2 systems, the actual consequences had a relatively small effect on the redundancy and availability of key safety functions. Unit 2 safety-related systems were maintained operable throughout the stator movement. The team concluded that the plant staff appropriately implemented the guidelines for risk management for Unit 2 operation at power.

8.0 Root Cause Analysis (Charter Item #8)

a. Inspection Scope

The team conducted an independent review of the licensee's initial actions taken to understand the cause of the crane failure. The team reviewed the organizational structure for the cause evaluation team and the problem statement developed by the licensee, inspected the work locations and facilities established for the cause evaluation team, and interviewed licensee and contract personnel. The assessment included a review of the licensee's criteria and methods for determining the cause of the event.

b. Observations

The team identified one unresolved item requiring follow-up inspection associated with this charter item.

Introduction. The team identified an unresolved item associated with the licensee's identified causes and planned corrective actions for the March 31, 2013, temporary crane failure.

Description. The licensee developed a corporate event response team to oversee the recovery and cause evaluation efforts following the collapse of the temporary crane on March 31, 2013. The licensee initiated condition report CR-ANO-C-2013-0888 to document the failure of the temporary crane and generated a corrective action associated with this condition report to track the cause evaluation efforts.

The licensee established a separate organizational structure devoted to the cause evaluation efforts, including independent consultants and subject matter experts. The licensee established work areas inside and outside the protected area for the cause evaluation team, and identified a secure laydown area for the removal of components of the temporary crane on the owner controlled area. Through review of the planned organizational structure and physical inspection of the available planned work areas, the team concluded the licensee's cause evaluation efforts were being conducted at a level of detail commensurate with the safety significance of the event.

The root cause evaluation effort was still in progress at the conclusion of the inspection. The team concluded additional follow-up inspection was necessary to assess the adequacy of the licensee's identified causes and corrective actions when completed: Unresolved Item URI 05000313/2013011-10, "Causes and Corrective Actions Associated with the Dropped Heavy Load Event."

9.0 Applicability of Operating Experience (Charter Item #9)

a. Inspection Scope

The team evaluated the licensee's application of industry operating experience related to this event. The team reviewed applicable operating experience and generic NRC communications with a specific emphasis on contractor oversight, control of heavy loads, and seismic monitoring equipment to assess whether the licensee had appropriately evaluated the notifications for relevance to the facility and incorporated applicable lessons learned into station programs and procedures.

b. Observations

Overall, the team concluded the licensee had appropriately incorporated the insights from industry operating experience into their corporate programs and implementing procedures.

.1 Contractor Oversight

The team reviewed operating experience related to contractor oversight. The team identified NRC operating experience discussed in Information Notice (IN) 97-74 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML031050083), "Inadequate Oversight of Contractors during Sealant Injection Activities," and industry operating experience documents. The NRC described in IN 97-74 that adequate understanding of the potential consequences and the exercise of adequate control of vendor activities were important to avoid adverse impact on safety-related systems as a result of sealant injection processes. Industry operating experience addressed the same issues with a broader consideration of vendor activities.

The team evaluated incorporation of the related operating experience in administrative procedures. The team reviewed procedure EN-MA-126, "Control of Supplemental Personnel," Revision 15, and concluded the procedure contained appropriate measures to exercise oversight of contractor activities. However, the degree of oversight was related to the perceived safety significance of the contractor activities.

The team discussed implementation of procedure EN-MA-126 with licensee project management staff. The project management staff indicated a focus on industrial safety based on the perception of very low risk of a handling system failure and the level of expertise of the contractors. The team reviewed the licensee plan for contractor oversight and determined that the plan was appropriate for the perceived risks. However, an unresolved item associated with the effectiveness of the licensee's implementation of risk management activities is described in Section 7.0 of this report.

.2 Control of Heavy Loads

The team reviewed recent operating experience related to heavy load movements. The NRC staff reemphasized guidelines for control of heavy load handling activities in

Regulatory Issue Summary (RIS) 2005-25, "Clarification of NRC Guidelines for Control of Heavy Loads," October 31, 2005, (ADAMS Accession No. ML052340485), including managing the risk of heavy load activities beyond the scope of existing heavy load handling programs under the requirements of 10 CFR 50.65(a)(4). In addition, the NRC discussed the industry initiative on control of heavy loads in NRC RIS 2008-28, "Endorsement of Nuclear Energy Institute Guidance for Reactor Vessel Head Heavy Load Lifts," (ADAMS Accession No. ML082460291), and endorsed Nuclear Energy Institute (NEI) 08-05, "Industry Initiative on Control of Heavy Loads," Revision 0 (ADAMS Accession No. ML082180684).

The team reviewed the licensee's implementation of the operating experience and guidance included in the above documents. Section 1, "Maintenance Rule 10 CFR 50.65(a)(4) Considerations," of NEI 08-05 provided guidelines for implementation of the risk management requirements of 10 CFR 50.65(a)(4) for heavy load movements. These guidelines specified the following risk management activities when components performing a protected safety function could be impacted by a potential load drop:

- Revising the load path to preclude movement over the operating train, or conducting the heavy load lift at a different time, e.g., after redundant equipment has been restored to service.
- Providing additional compensatory actions or backup safety functions to enhance redundancy of safety function performance during the heavy load lift.
- Providing additional communication and awareness to operations and maintenance personnel of the load lift and its relation to maintenance activities.
- Obtaining approval of plant management of the heavy load lift.

The team determined that the licensee appropriately incorporated these risk management activities into the material handling program implementing procedure EN-MA-119. However, an unresolved item associated with the effectiveness of the licensee's implementation the material handling program is described in Section 7.0 of this report.

.3 Seismic Monitoring

The team reviewed operating experience related to seismic instrumentation and associated monitoring and alarm systems for operating reactors. The team identified NRC operating experience discussed in Information Notice 2012-25, "Performance Issues with Seismic Instrumentation and Associated Systems for Operating Reactors" (ADAMS Accession No. ML121590444), and industry operating experience documents. The NRC described in Information Notice 2012-25 an occurrence where seismic instrumentation and associated monitoring and alarm systems did not provide reliable indications and alarms. Thus, plant operators were unable to promptly determine if the ground motion levels exceeded the operating basis earthquake ground motion levels.

The team evaluated incorporation of the related operating experience. The licensee evaluated Information Notice 2012-025 through the corrective action program in condition report CR-ANO-C-2013-00348. The licensee had replaced all of the scratch plate type seismic monitoring systems at Arkansas Nuclear One with a digital system in 2012. The old scratch plate system required a third party to interpret the data, whereas the digital system provides onsite readout. Arkansas Nuclear One has six seismic monitors located at various locations on site, with three providing alarms to the control room and the other three as standalone units. The six monitoring systems were checked after the March 31 event, and only one stand-alone unit recorded data above the 0.01g trigger level. This unit was located on the Unit 1 Spent Fuel Pool Deck (Elevation 404') and recorded 0.01759g horizontal and 0.03865g vertical vibrations.

The team concluded the licensee had appropriately evaluated operating experience associated with seismic instrumentation. The team evaluated the differences between a seismic event (inertial forces created by ground accelerations) and the impact load (dynamic effect on a structure of a forcible momentary contact of a moving body) from the March 31 event and concluded the seismic monitoring recordings functioned as designed.

10.0 Independent Risk Assessment (Charter Item #10)

a. Inspection Scope

The team reviewed the sequence of events and equipment performance to support an independent assessment of the risk for the dropped stator event.

b. Observations

NRC senior reactor analysts originally estimated the risk from the March 31 event using the Arkansas Nuclear One, Unit 2, Standardized Plant Analysis Risk (SPAR) model, Revision 8.21, Inspection Manual Chapter 0609, Appendix G, Attachment 2, and other qualitative assessment tools. The analysts assumed that the event in Unit 2 was similar to an uncomplicated reactor transient with Switchgear 2A2 out of service. The resulting conditional core damage probability (CCDP), 1.1×10^{-6} , indicated the lower bound of the risk from the drop. Assuming that the risk could be bounded on the high side by modeling the event as a plant-centered loss of offsite power, the CCDP was estimated as 1.3×10^{-5} .

For Unit 1, the analysts used Figure 8 from Appendix G, Attachment 2, to assess the risk of the event. The licensee informed the analysts that one of the breakers required to power the vital buses from the alternate ac diesel generator was not available because of potential damage from the event. Therefore, the analysts estimated the probability of an emergency power supply system demand failure at 4.49×10^{-3} , assuming that only diesel generators 1 and 2 were available to supply vital loads. Given that offsite power had not been restored within 36 hours and was not expected to be returned for some time, the analysts set the probability of failure to restore offsite power to 1.0. The probability of not recovering a postulated diesel generator failure within 18 hours was

estimated using the SPAR as 3.63×10^{-1} . The analysts used an initial screening value of 0.1 for the probability of alternative strategies failure leading to core damage. The resulting estimated CCDP was 1.6×10^{-4} , which was in the range for an augmented inspection team using Management Directive 8.3, "NRC Incident Investigation Program."

Based on their review of the sequence of events and discussions with operators, the team concluded the risk assumptions used by the senior reactor analysts to model the event were appropriate. The information collected by the inspectors will be used to further refine the risk calculation used for the significance determination process for any findings identified during follow-up inspection.

11.0 Exit Meeting Summary

On May 9, 2013, the NRC held a public meeting and presented the inspection results to Mr. J. Browning and other members of the staff, who acknowledged the observations. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

D. Bauman	Manager, Project Management
B. Buser	Senior Electrical Design Engineer
T. Chernivec	Unit 2 Outage Manager
M. Chisum	General Manager Plant Operations
G. Dobbs	Design Engineering Electrical Supervisor
M. Farmer	Work Week Manager
M. Gohman	Unit 1 Shift Manager
J. Hathcote	Unit 2 Assistant Operations Manager
R. Harris	Emergency Preparedness Manager
D. James	Nuclear Safety Assurance Director
C. Johnson	Civil Engineer
W. Maguire	Vice President, Operations Support
J. McMahan	Senior Project Manager
E. McCormic	Senior Outage Scheduler
J. McCoy	Engineering Director
D. Pehrson	Unit 1 Shift Manager
D. Perkins	Maintenance Manager
S. Pyle	Licensing Manager
L. Schwartz	Design Engineer
J. Scroggins	Contract Engineer
C. Shively	Systems Engineer
G. Sullins	Assistant Operations Supervisor
J. Tobin	Security Manager
C. Tucker	Field Implementing Supervisor
P. Williams	Operations Manager
T. Woodson	Systems Engineering Supervisor

NRC Personnel

A. Fairbanks	Resident Inspector
W. Schaup	Resident Inspector
S. Pannier	Reactor Systems Engineer
R. Azua	Senior Project Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000313; 368/2013011-01	URI	Control of Temporary Modification Associated with the Temporary Fire Pump (Section 2.b.3)
05000313; 368/2013011-02	URI	Damage to Unit 1 and Unit 2 Structures, Systems and Components (Section 3.b)
05000313/2013011-03	URI	Procedural Controls Associated with Unit 1 Steam Generator Nozzle Dams (Section 4.b.1)
05000368/2013011-04	URI	Main Feedwater Regulating Valve Maintenance Practices (Section 4.b.2)
05000313/2013011-05	URI	Flood Barrier Effectiveness (Section 4.b.3)
05000313; 368/2013011-06	URI	Compensatory Measures for Firewater System Rupture (Section 5.b)
05000368/2013011-07	URI	Timeliness of Emergency Action Level Determination (Section 6.b)
05000313/2013011-08	URI	Effectiveness of Shutdown Risk Management Program (Section 7.b.1)
05000313/2013011-09	URI	Effectiveness of Material Handling Program (Section 7.b.2)
05000313/2013011-10	URI	Causes and Corrective Actions Associated with the Dropped Heavy Load Event (Section 9.b)

LIST OF DOCUMENTS REVIEWED

DRAWINGS

<u>Number</u>	<u>Title</u>	<u>Revision</u>
11405-E-1	Main One Line Diagram P & ID	49
27619-001	Isometric Drawing – Stator Gantry Lift and Stator Exchange Project, Unit 1	
SAR FIG. 8-1	UNIT 1 Station Single Line Diagram	21
SAR FIG. 8.3-1	UNIT 2 Station Single Line Diagram	20
E-3	UNIT 1 Single Line Meter & Relay Diagram 6900 Volt System	22
E-4	UNIT 1 Single Line Meter & Relay Diagram 4160 Volt System, Main Supply	26

<u>Number</u>	<u>Title</u>	<u>Revision</u>
E-5	UNIT 1 Single Line Meter & Relay Diagram 4160 Volt System, Engineered Safeguard	25
E-2003	UNIT 2 Single Line Meter & Relay Diagram 6900 Volt System	20
E-2004	UNIT 2 Single Line Meter & Relay Diagram 4160 Volt System, Main Supply	19
E-2005	UNIT 2 Single Line Meter & Relay Diagram 4160 Volt System, Engineered Safety Features	30
A-100	Turbine & Auxiliary Building Floor Plan 354'	26
A-107	Auxiliary Building Floor Plans 317' & 335'	26
M-219	Unit 1 Fire Water	83
M-2219	Unit 2 Fire Water	61

PROCEDURES

<u>Number</u>	<u>Title</u>	<u>Revision</u>
COPD-024	Risk Assessment Guidelines	7
EN-MA-119	Material Handling Program	16
EN-MA-126	Control of Supplemental Personnel	15
EN-OP-116	Infrequently Performed Tests or Evolutions	11
EN-OU-108	Shutdown Safety Management Program	5
OP 1015.048	Shutdown Operations Protection Plan	9
EN-OP-117	Operations Assessments	6
OP-5120.504	OTSG Nozzle-Dam Training, Testing & Installation/Removal	6/7
OP-1104.032	Fire Protection Systems	71
OP-1104.034	Control Room Air Conditioning	32
PFP-U1	ANO-Pre Fire Plan Unit 1	15
OP-1015-.037	Post Transient Review	10
OP-1903.010	Emergency Action Level Classification	46

CALCULATIONS

<u>Number</u>	<u>Title</u>	<u>Revision</u>
27619-C1	Heavy Lift Gantry Calculation – ANO Stator Replacement Project	0

MISCELLANEOUS DOCUMENTS

<u>Number</u>	<u>Title</u>	<u>Revision/Date</u>
1R24	ANO Unit 1 Outage Schedule (Green Train and Stator) AIS Manual of Steel Construction	April 9, 2013 14 th Ed.
ASME NQA-1	Quality Assurance Requirements for Nuclear Facility Applications	2012
EN-LI-100	Process Applicability Determination for EC43686 Attachment 9.1 Assessment of ANO-1 Operator Response on 3/31/2013 Sequence of Events for Securing Fire Water 3/31/2013 Timeline for ANO1 SG Nozzle Dams during 1R24 Compensatory Measures Taken as a Result of the Stator Drop Event Security Incident Report 2013-0283: Generator Drop Accident Fire Impairment List as of April 9, 2013 Preliminary Assessment of Seismic Monitor Recordings Generated from Main Generator Stator Drop on March 31, 2013	13
FS-009	Firewater System Rupture Tagout	

VENDOR MATERIALS

<u>Number</u>	<u>Title</u>	<u>Revision</u>
101	Procedure - Erection/Dismantle, Siemens ANO Power Station – Unit 1	4

MODIFICATIONS

<u>Number</u>	<u>Title</u>	<u>Revision</u>
EC 43686	Temporary Modification Evaluation (TMEV) Engineering Change Format Attachment 9.11	1
EC-43521	Acceptability of ANO-2 Fast Transfer Capability during 1R24	
EC-42218	ICW Pump Alternate Power Source Connection	

WORK ORDERS (WO)

WO-346588 WO-341220

CONDITION REPORTS (CR-)

ANO-1-2013-00132	ANO-2-2013-00585	ANO-C-2013-00633	ANO-2-2013-00661
ANO-1-2000-00169	ANO-1-2013-00842	ANO-2-1991-00060	ANO-2-2013-00583
ANO-2-2013-00606	ANO-2-2013-00672	ANO-2-2013-00693	ANO-C-2013-00348
ANO-C-2013-00888	ANO-2-2013-00736	ANO-1-2013-00868	ANO-2-2013-00620
ANO-2-2013-00583	ANO-2-2013-00132		

ATTACHMENT 2
SEQUENCE OF EVENTS

<u>Date/Time</u>	<u>Event Description</u>
March 24, 2013 8:26 a.m.	Unit 1 opened output breakers and commenced refueling outage
March 27, 2013 6:10 a.m.	Unit 1 entered Mode 6, first reactor vessel head bolt de-tensioned.
March 31, 2013 00:00:00	Unit 2 at 100% power
12:49 a.m.	Temporary crane assembly completed on Unit 1 turbine deck
5:20 a.m.	Unit 1 cross-tied buses B1 and B2 with bus B1 supplying.
5:25 a.m.	Unit 1 cross-tied buses B3 and B4 with bus B3 supplying.
5:42 a.m.	Unit 1 cross-tied buses B5 and B6 with bus B5 supplying.
6:08 a.m.	Unit 1 cross-tied buses A3 and A4 with bus A3 supplying.
6:39 a.m.	Lift of Unit 1 stator began
6:49 a.m.	Unit 1 Bus A2 de-energized for maintenance (Green train).
7:35 a.m.	Unit 1 Operators opened battery D-06 disconnect in preparations for Green train maintenance. Battery charger D-04B is powered from Red train.
7:50 a.m.	The Unit 1 temporary overhead crane failed resulting in the drop of the stator. This caused a loss of off site power on Unit 1. Unit 1 Emergency Diesel Generators 1 and 2 started and supplied bus A3 4160V switchgear and bus A4 4160V Switchgear. Service water pumps P-4A and P-4C verified running. Unit 1 entered Procedures 1202.007, "Degraded Power," 1203.028 "Loss of Decay Heat," and 1203.050 "Spent Fuel Emergencies." Unit 2 reactor coolant pump RCP 2P-32B tripped resulting in a Unit 2 reactor trip. Unit 2 entered Mode 3.
7:51 a.m.	Unit 1 entered TS 3.8.2 A.2 for one required offsite circuit inoperable. Unit 1

4160 vital buses A3 and A4 separated following loss of off-site power.

- 7:52 a.m. Unit 1 entered TRM 3.7.6 Condition A for the Spent Fuel Cooling System being non-functional. Condition A.1 met.
- 7:54 a.m. Unit 1 re-started decay heat pump P-34A and established a cool down rate.
Unit 2 secured Reactor Coolant Pump 2P-32D to balance RCS heat removal due to Reactor Coolant Pump 2P-32B trip. Unit 2 Control room received report of a rupture of the fire water header.
- 7:59 a.m. Unit 1 control room received reports from Unit 2 that Unit 2 Instrument Air compressors are functioning properly. Unit 1 instrument air compressors were de-energized due to loss of power to motor control centers B-32 and B-42.
- 8:00 a.m. Unit 1 Shift manager requested the OCC set containment closure based on outside reports of potential structural damage to the plant.
Unit 2 control room operators identified main feedwater did not go to Reactor Trip Override because main feedwater regulating valve 2CV-748 indicated mid-position. Operators tripped main feed pump A and actuated EFAS. Main feedwater regulating valve 2CV-748 was actually closed, but indicated mid-position due to failed limit switch.
- 8:01 a.m. Unit 1 dispatched an operator to secure fire water pump P-6B due to leakage into the Unit 1 turbine building.
- 8:02 a.m. Unit 1 operators manually inhibited feeder breakers for buses A1 and A2 by placing the control switches in pull-to-lock in accordance with Procedure 1203.007, "Degraded Power."
- 8:03 a.m. Unit 1 shift manager requested that electricians be dispatched to inspect A1 and A2 switchgear. Unit 1 operators manually inhibited the feeder breakers for 6900 Volt buses H1 and H2.
Diesel driven fire pump secured. Unit 1 log erroneously records all fire pumps secured, including temporary fire pump
- 8:04 a.m. Unit 1 entered TRM 3.7.8 Condition B 24 hour time clock for two high pressure fire water pumps non-functional.
- 8:05 a.m. Unit 1 operators started decay heat pump P-34B
- 8:06 a.m. Unit 1 reactor building equipment hatch was closed
- 8:11 a.m. Unit 1 completed isolation of containment.

- 8:13 a.m. Unit 1 operators re-started spent fuel pool cooling pump P-40B in accordance with procedure 1203.050, "Spent Fuel Emergencies." Pump P-40B started to re-circulate the Spent Fuel Pool. Intermediate cooling water was out of service.
- 8:14 a.m. Unit 1 decay heat trains A and B were in service. Train A in service with ~3300 GPM flow and train B in service with ~1200 GPM flow. No reactor coolant system heat-up in progress.
- 8:16 a.m. Unit 2 operators started auxiliary feedwater pump 2P-75.
- 8:17 a.m. Unit 2 control room receives report of water getting on the condensate pump 2P-2A motor, which is not running. Operators placed the control switch for pump 2P-2A in pull-to-lock. Operators secured emergency feedwater pump 2P-7A by overriding EFAS actuation and entered Technical Specification 3.7.1.2 due to pump 2P-7A unable to automatically start.
- 8:18 a.m. Unit 2 operators secured emergency feedwater pump 2P-7B due to EFAS actuation and entered Technical Specification 3.0.3 for both emergency feedwater pumps inoperable.
- 8:19 a.m. A Unit 1 operator was dispatched to investigate the cause of Auxiliary building sump level reading 100%.
- 8:20 a.m. Unit 1 reactor operator reported that reactor building sump level was stable. Unit 1 closed generator hydrogen bank 3 isolation valve H2-101 and verified all other generator hydrogen bank outlets closed per procedure OP-1106.002 exhibit D. Generator hydrogen secured to both Unit 1 and Unit 2.
- 8:23 a.m. Unit 1 operator reported the source of water on the 317' elevation of the auxiliary building is from fire water leaking into the Unit 1 auxiliary building from the turbine building.
- 8:27 a.m. Unit 1 building operator reported water leaking near spent resin tank T-13. Radiation protection dispatched to assist in leak investigation.
- 8:29 a.m. Unit 1 shift manager initiated staffing of the emergency response organization.
- 8:31 a.m. Further reports from plant operators indicated that damage from the temporary crane collapse was limited to the train bay and turbine deck area. The fuel transfer canal level and spent fuel pool level remained stable.
- Unit 1 investigation of sump level rise revealed firewater leaking into the Unit 1 auxiliary building from a ruptured firewater pipe in the Unit 1 turbine building train bay.

- 8:33 a.m. Unit 1 operators started decay heat pump P-34B. Decay heat pumps A and B were operating and being powered from emergency diesel generators 1 and 2, respectively.
- 8:41 a.m. Unit 1 operators closed turbine building fire water train bay isolation valve FS-18, west turbine building fire water cross-connect valve FS-38, and Unit1/Unit 2 cross-connect isolation valve 2FS-5009 to isolate the firewater leak in the turbine building.
- 8:44 a.m. Unit 2 EFAS was reset.
- 8:48 a.m. Unit 1 Shift Manager requested that outage control center install temporary modification to power intermediate cooling water pump P-33C from the London line.
Unit 2 pump 2P-7A discharge valves re-aligned to their normal positions from their EFAS actuated positions. Unit 2 exited TS 3.0.3.
- 8:57 a.m. Unit 1 Fire Hydrant 1 opened to lower pressure in the firewater system to slow the firewater leak per control room instruction. Hydrant 1 was then re-closed.
- 9:03 a.m. Unit 1 log entry indicated that there temporary fire pump was secured to aid in depressurizing the fire main.
- 9:23 a.m. Unit 2 Startup 3 Transformer locked out. After the transformer lockout, startup 2 supplied buses 2A1 and 2A3. Bus 2A2 was de-energized and bus 2A4 was powered from emergency diesel generator 2. All reactor coolant pumps were secured. Auxiliary feedwater pump 2P75 tripped due to startup transformer 2 load shed. Loss of spent fuel pool cooling due to loss of power to pump 2P-40B. Instrument air compressors were de-energized due to startup transformer 3 lockout.
Unit 2 operators entered TS 3.8.1.1 action a.1 and a.2 due to startup transformer 3 lockout and entered TS 3.4.1.2 actions a and b due to no reactor coolant pumps running. Operators re-entered Standard Post Trip actions for re-diagnosis.
- 9:25 a.m. Unit 2 control room received reports of damage to switchgear 2A1 and surrounding area, stating that one of the breaker doors on bus 2A1 was knocked open (unable to determine which breaker at this time). There was light smoke from the back of one breaker in bus 2A1 but no fire. There was standing water around the switchgear.
- 9:27 a.m. Unit 1 operators entered Abnormal Operating Procedure 1203.024, "Loss of Instrument Air."
- 9:29 a.m. Unit 1 operators reported that intermediate cooling water pump P-33C was reported ready to be energized from the London line.

- Unit 2 operators entered the Natural Circulation abnormal operating procedure and exited Reactor Trip Recovery.
- 9:30 a.m. Unit 1 operators started intermediate cooling water pump P-33C, power supply is from the London Line.
- 9:36 a.m. Unit 1 operators secured intermediate cooling water pump P-33C due to the cross-tie valves closing on loss of instrument air pressure.
Unit 2 letdown was isolated with valve 2CV-4820 due to loss of instrument air pressure.
- 9:46 a.m. Unit 1 local spent fuel pool level monitor placed in service when the air fed level monitor was lost due to loss of instrument air.
- 9:47 a.m. Unit 2 operators placed one instrument air compressor in service.
- 9:52 a.m. Unit 2 commenced steaming steam generators A and B to atmosphere using upstream atmospheric dumps.
- 9:53 a.m. Unit 2 completed all applicable steps from the Fire and Explosion abnormal operating procedure.
- 9:58 a.m. Unit 2 operators entered Loss of Instrument Air abnormal operating procedure.
- 10:09 a.m. Unit 2 operators commenced feeding steam generators A and B with emergency feedwater pump 2P-7B.
- 10:12 a.m. Unit 2 operators secured emergency feedwater pump 2P-7A.
- 10:14 a.m. Unit 2 control room received and investigated a report of significant water hammer from the East Heater Deck.
- 10:15 a.m. Unit 2 spent fuel pool cooling pump 2P-40A was started.
- 10:23 a.m. As a contingency, two diesel driven fire pumps (on trailers) were staged at the intake structure and at the domestic water hydrant north of the central support building.
- 10:31 a.m. Unit 1 intermediate cooling water pump P-33C was restored once adequate instrument air header pressure was available to open the suction and discharge cross-tie valves to restore a normal lineup.
- 10:33 a.m. Unit 2 operators declared Notification of Unusual Event (NUE) due to damage to switchgear 2A1 and startup transformer 3 lockout.

- 10:36 a.m. Unit 2 operators started containment coolers 2VSF-1B, C, and D with service water aligned since main chilled water cooling was not available.
- 10:48 a.m. Unit 2 operators completed initial offsite notifications for Notification of Unusual Event.
- 11:33 a.m. Unit 2 operators energized bus 2B2 from bus 2B1 so that both instrument air compressors could be placed in service.
- 11:40 a.m. Unit 2 operators started instrument air compressor 2C-27B. Both Unit 2 instrument air compressors were running. Instrument air pressure was approximately 40 psig until compressor B was placed in service. Instrument air pressure then was maintaining approximately 90 psig.
- 11:42 a.m. Unit 1 building operator reported that there was 1-inch of water standing in decay heat vault B. Decay heat vault room drains were verified closed. Firewater leaking into elevation 317 had stopped and water level was stable in decay heat vault B. Level did not have the potential to impact safety related equipment.
- 12:20 p.m. Unit 2 restored letdown flow with charging pump 2P-36C.
- 12:53 p.m. Unit 1 operators stopped spent fuel pool pump P-40B and started pump P-40A to fill the spent fuel pool.
- 1:12 p.m. Unit 1 operators commenced filling the spent fuel pool.
- 1:14 p.m. Unit 1 spent fuel pool low level alarm cleared. The low level alarm was in prior to losing off-site power due to the reactor coolant system level with the transfer tube isolation (SF-4) open. Spent fuel pool level was stable with no indication of leakage.
- 1:26 p.m. Unit 1 operators secured filling the Spent Fuel Pool, final pool level is +0.4 ft. Unit 1 normal control room phones verified functioning.
- 1:31 p.m. Unit 2 Control room received a report that bus 2A9 was degraded; therefore, the alternate AC diesel generator was unavailable for either unit.
- 1:33 p.m. Unit 1 started spent fuel pool cooling pump P-40B for spent fuel pool cooling.
- 1:35 p.m. Unit 1 DC control power was removed from buses A1, A2, B3, B4, H1, and H2 due to indicated ground on battery bank D02.
- 1:38 p.m. Unit 1 local spent fuel pool level monitor secured.
- 1:52 p.m. Unit 1 battery bank D02 ground cleared locally.

- 1:55 p.m. Unit 1 emergency diesel generator 1 non-critical trouble alarm due to low starting air pressure due to loss of power to the starting air compressors.
- 2:10 p.m. A third diesel driven fire pump (on trailer) was staged on the South West end of the yard between the system engineering building and secondary degas building.
- 2:26 p.m. Unit 2 operators commenced reactor coolant system cooldown.
- 3:03 p.m. Unit 1 operators began isolating individual deluge isolations in preparation for restoring the Fire water header.
- 3:21 p.m. Unit 1 battery disconnect D-06 reclosed.
- 3:42 p.m. All Unit 1 and Unit 2 Deluge Sprinkler Systems (open sprinkler heads) were isolated in preparation for fire suppression system restoration.
- 3:58 p.m. Unit 2 operators closed both main steam isolation valves.
- 5:00 p.m. Unit 1 outage risk was determined to be Red due to not meeting Electrical System requirements for Shutdown Operations Protection Plan Condition 2. Unit 1 was unable to utilize off-site power. Both emergency diesel generators were in service supplying safety system loads.
- 11:35 p.m. Unit 2 alternate AC diesel generator 4160V output breaker was racked out to protect bus 2A9 for Unit 1 and Unit 2.
- 11:54 p.m. Unit 1 emergency temporary modification installation was authorized for aligning power from startup transformer 1 to buses A3 and A4 via cross-tie breakers A-310 and A-410.
- 11:55 p.m. Unit 2 entered Mode 4 and operators exited Technical Specification 3.7.1.2 for emergency feedwater and 3.4.1.2 for the reactor coolant loops (no longer in a mode of applicability). Operators entered Technical Specification 3.4.1.3 for reactor coolant loops in Mode 4.

April 1, 2013

- 12:54 a.m. Unit 2 operators placed low temperature overpressure protection relief valves in service per procedure 2102.010, "Plant Shutdown."
- 3:51 a.m. Unit 2 secured steaming steam generators A and B to atmosphere.
- 4:29 a.m. Unit 2 operators placed two loops of shutdown cooling in service. All actions required of Natural Circulation Operations were completed, and operators exited the Natural Circulation abnormal operating procedure.

April 2, 2013

3:27 a.m. Unit 2 emergency diesel generator 2 secured following the restoration of normal power to bus 2A4 from bus 2A2.

April 6, 2013

2:51 a.m. Operators restored offsite power to Unit 1 vital bus A3 via a temporary modification from Startup Transformer 1.

3:24 a.m. Unit 1 emergency diesel generator 1 secured.

1:47 p.m. Operators restored offsite power to Unit 1 vital bus A4 from bus A3.

2:03 p.m. Unit 1 emergency diesel generator 2 secured. All emergency diesel generators secured.

ATTACHMENT 3: AUGMENTED INSPECTION TEAM CHARTER



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

April 5, 2013

MEMORANDUM TO: Geoffrey Miller, Chief, Engineering Branch 2
Division of Reactor Safety

FROM: Arthur T. Howell III, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER TO EVALUATE THE
MAIN STATOR DROP AND LOSS OF OFFSITE POWER EVENT AT
ARKANSAS NUCLEAR ONE

You have been selected to lead an Augmented Inspection Team to assess the circumstances surrounding the lifting rig failure event resulting in a loss of offsite power for Arkansas Nuclear One Unit 1, a partial loss of offsite power for Unit 2, and a Notification of Unusual Event declaration on March 31, 2013. The following are the other team members:

- Alfred Sanchez (Region IV)
- John Watkins (Region IV)
- Steve Jones (NRR)

A. Basis

On March 31, 2013, a temporary lifting rig being used to move the Unit 1 main generator stator failed, resulting in a loss of offsite power for ANO Unit 1, a reactor trip of ANO Unit 2, and structural damage to the turbine building and portions of the fire suppression systems. Subsequently, at 9:22 a.m., water intrusion into a breaker cubicle from Startup Transformer #3 caused a catastrophic breaker fault, isolating power to one train of vital power for Unit 2 and causing the Train B emergency diesel generator to start. At 10:42 a.m., the licensee declared a Notice of Unusual Event based on the catastrophic breaker failure. The emergency notification was terminated at 6:21 p.m. At the time of the event, Unit 1 was in a refueling outage with the refueling canal flooded and steam generator nozzle dams installed.

In accordance with Management Directive 8.3, "NRC Incident Investigation Program," deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. Two deterministic criteria were met for multiple failures in systems needed to mitigate an actual event and possible adverse generic implications associated with the lifting of heavy loads. The initial risk assessment, while subject to some uncertainties, indicated that the conditional core damage probability for the event is in the range for an augmented inspection. Region IV, in consultation with the Office of Nuclear Reactor Regulation (NRR), concluded that the NRC response should be an augmented inspection. This augmented inspection is chartered to identify

the circumstances surrounding this event, review the licensee's actions following discovery of the conditions, and evaluate the licensee's response to the event.

B. Scope

The augmented inspection team is to perform data gathering and fact finding in order to address the following:

1. Develop a detailed chronology of significant events associated with the failure of the lifting rig.
2. Assess operator actions in response to the event.
3. Assess the impact of the dropped load on Unit 1 and Unit 2 structures, systems and components.
4. Evaluate whether plant systems responded as expected following the failure of the lifting rig. Compare the actual plant response to the applicable safety analyses.
5. Assess the adequacy of licensee compensatory measures implemented in response to the equipment damage caused by the failure of the lifting rig.
6. Evaluate the appropriateness and timeliness of the licensee's event classification and reporting.
7. Assess the adequacy of the licensee's preparations for the heavy lift including procedure use and adequacy, and risk assessment and management actions.
8. Review the current status of the licensee's root cause analysis and determine whether it is being conducted at a level of detail commensurate with the significance of the event.
9. Review applicable operating experience and/or generic NRC communications and determine if the licensee developed appropriate actions in response to the information.
10. Collect data to support an independent assessment of the risk significance of the event.

C. Guidance

Inspection Procedure 93800, "Augmented Team Inspection," provides additional guidance to be used during the conduct of the inspection. Your duties will be described in this procedure and should emphasize fact-finding in the review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory

process. Safety or security concerns identified that are not directly related to the event should be reported to the Region IV office for appropriate action.

NRC inspection of this event began on March 31, 2013. The augmented inspection team will begin in-office inspection the week of April 1, 2013, and report to the site and conduct an entrance meeting on April 8, 2013. The onsite portion of the inspection should be completed within the next two weeks. You should provide a recommendation concerning when onsite inspection should be concluded after you are on site.

An initial briefing of Region IV management will be provided on April 8, 2013, with daily briefings thereafter. In accordance with Inspection Procedure 93800, you should promptly recommend a change in inspection scope or escalation if information indicates that the assumptions used in the MD 8.3 risk analysis were incorrect.

Upon arrival onsite, discuss the scope of the augmented inspection with representatives from the Occupational Safety and Health Administration. Ensure we have an understanding of each agency's roles and responsibilities related to the inspection of this event.

A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection. The report should address all applicable areas specified in Section 03.02 of Inspection Procedure 93800. At the completion of the inspection, you should provide recommendations for improving the Reactor Oversight Process baseline inspection procedures and Augmented Inspection process based on any lessons learned.