Group C

# FOIA/PA NO: 2014-0024

# RECORDS BEING RELEASED IN PART

The following types of information are being withheld:

Ex. 3: ☐ Information about the design, manufacture, or utilization of nuclear weapons
☐ Information about the protection or security of reactors and nuclear materials
☐ Contractor proposals not incorporated into a final contract with the NRC
☐ Other_____

Ex. 4: ☐ Proprietary information provided by a submitter to the NRC
☐ Other_____

Ex. 5: ☒ Draft documents or other pre-decisional deliberative documents (D.P. Privilege)
☐ Records prepared by counsel in anticipation of litigation (A.W.P. Privilege)
☐ Privileged communications between counsel and a client (A.C. Privilege)
☐ Other_____

Ex. 6: ☒ Agency employee PII, including SSN, contact information, birthdates, etc.
☐ Third party PII, including names, phone numbers, or other personal information

Ex. 7(A): ☐ Copies of ongoing investigation case files, exhibits, notes, ROI's, etc.
☐ Records that reference or are related to a separate ongoing investigation(s)

Ex. 7(C): ☐ Special Agent or other law enforcement PII
☐ PII of third parties referenced in records compiled for law enforcement purposes

Ex. 7(D): ☐ Witnesses' and Allegers' PII in law enforcement records
☐ Confidential Informant or law enforcement information provided by other entity

Ex. 7(E): ☐ Law Enforcement Technique/Procedure used for criminal investigations
☐ Technique or procedure used for security or prevention of criminal activity

Ex. 7(F): ☐ Information that could aid a terrorist or compromise security

Other/Comments: Some copyright

**Baca, Bernadette**

**From:** Kennedy, Kriss
**Sent:** Friday, April 05, 2013 5:01 PM
**To:** Draper, Jason; Loveless, David; Miller, Geoffrey; Watkins, John; Hay, Michael; Lantz, Ryan; R4DRP-DIV; Blount, Tom; Clark, Jeff; Vegel, Anton; Howell, Art; Lewis, Robert; Pruett, Troy; George, Gerond; Campbell, Vivian
**Subject:** DRP WEEKLY INFORMATION

**DRP Team,**

To facilitate communications and information flow in the division, the information below is a summary of the topics discussed during the DRP Coordination Meeting conducted on April 2 and other miscellaneous topics from this week's activities.

**ACTIONS**

Complete **testing of telecommunications equipment** no later than **April 15** (See RON 0120.30) ( Open ADAMS P8 Document (RN 0120.30 Response Voice Telecommunications))

**INFORMATION**

As you have all heard by now, there was a significant event last Sunday at **Arkansas Nuclear One** involving the collapse the lifting rig being used to move the 600 ton main generator stator out of the turbine building. The failure resulted in one fatality and several injuries. There was extensive damage to the turbine building, Unit 1 lost all offsite power, and Unit 2 tripped when a reactor coolant pump breaker opened. The branch did a great job in responding to the event and monitoring licensee actions this week. **Thanks** to **Fred Sanchez, Abin Fairbanks, for their initial response, and Ray Azua, Jim Melfi, Don Allen, David Loveless, Wayne Walker, Geoff Miller, John Watkins, Russ Lusk** (apologies if I left someone off the list) for all your work in developing internal and external communications, and completing the MD8.3 evaluation and the inspection charter. We will conduct an augmented inspection and the team will begin onsite Monday morning. The **team** members are **Geoff Miller (lead), Steve Jones (NRR), John Watkins, and Fred Sanchez.**

**Additional thought** on the ANO event – we are all very aware that you do not stand or walk under a load that is being lifted or is suspended. The ANO event demonstrates that lifting rigs can fail, and that the danger goes beyond the area under the load. Maintain safe distances from these activities – view from afar or with remote cameras, if used. **Be careful – Be Safe.**

Outside of Scope

**Congratulations** to **Dan Bradley** on his selection for the Resident Inspector position at Columbia Generating Station. **Well done Dan!**

**Congratulations** to **David You** on his selection as the temporary Resident Inspector at South Texas Project. **Well done David!**

This was **Gerond George's** last week onsite as the acting SRI at San Onofre. **Thanks for the support Gerond.**

**Jason Dykert** begins his assignment as the **temporary Callaway Resident Inspector**

Next week (April 8-12), the **John Kramer** and **Brian Tindell** will host two inspectors from Spain and one inspector from France to observe outage related inspection activities. This inspection is part of an NRC led effort to pilot and develop an international inspector exchange program, which was initiated by the NRC through the Nuclear Energy Agency's Working Group on Inspection Practices (WGIP). A second pilot inspection will be performed at the Cofrentes Nuclear Power Plant in Spain tentatively the week of October 14, 2013, and will include John Kramer along with inspectors from Korea, Canada, and Spain. The WGIP intends to use these pilot inspections to develop a long-term inspector exchange program.

**Thanks** to all who contributed to the success of Region IV's presentation to Eric Leeds, Jim Wiggins, and members of their staff during the End-of-Cycle Summary Meeting. **Matt Young, Mike Hay, David Proulx, and Ryan Lantz** did an outstanding job in providing clear and concise briefings on Columbia Generating Station, Fort Calhoun Station, Cooper, and SONGS. Region IV is the only Region that has the Branch Chiefs (or actors) to make these presentations. The summary for the other Regions is typically provided by the DRA or RA. **Great job guys!**

**ROP Enhancement Project –** Please continue to provide comments to **Neil O'Keefe** on ways to improve the baseline inspection procedures and the ROP.

**May 2013 Resident Inspector Counterpart Meeting –** the next Resident Inspector Counterpart Meeting will be held May 14-16. Please provide any ideas for meeting topics or training sessions to your BC and/or **Ray Kellar**. **Russ Lusk** is working with the administrative assistants to develop an agenda for a meeting of the site admin assistants. Please provide potential topics and training ideas to Russ.

We are in various stages (preparing to post, posted, interviewing) in the selection process for the following positions:

- Wolf Creek resident inspector
- ANO resident Inspector
- Wolf Creek temporary resident inspector
- Resident Inspector Development Program positions (3-4). We have made 2 offers, one has accepted, the other is in process.

**UPCOMING EVENTS**

Wolf Creek EOC Public Meeting – April 18

Administrative Professionals Day – April 24

Commissioner Magwood visit to FCS – May 2

RI and AA Counterpart Meetings – May 14-16

IP 95002 inspection at Wolf Creek – date TBD

**Have a great weekend.**

Kriss

## Miller, Geoffrey

**From:** Maier, Bill
**Sent:** Tuesday, April 30, 2013 8:48 AM
**To:** Blount, Tom; Kennedy, Kriss; Scott, Michael; Clark, Jeff; Miller, Geoffrey; Allen, Don
**Cc:** Lewis, Robert
**Subject:** AO REPORT FROM ANO STATOR DROP EVENT WILL BE NEEDED
**Attachments:** OEI NAPS FY 11.docx; OEI Guidance from MD 8-1.docx

Gentlemen:

Since the ANO stator drop event prompted the dispatch of an Augmented Inspection Team, it will need to be considered for inclusion in the FY 2013 Abnormal Occurrence Report to Congress as an "Other Event of Interest".

As the AIT report comes together, you might want to think about parallel construction of a short narrative for Appendix C of the Report to Congress. Appendix C submittals are not constrained by format, so there is some freedom allowed in the development of these items. The absolute deadline for submittal of final write-ups is in November; however, RES desires some form of documentation as soon as enough information is known about an event to write something about it.

As a guide, I am attaching the final version of the Appendix C write-up for the North Anna Seismic Event of 2011, which was documented in the FY 2011 AO Report. This description is as close of an event to the ANO stator drop as I could find. I am also attaching the pertinent parts of the AO Handbook from Management Directive 8.1 that give guidance on development of Other Events of Interest.

Feel free to call me if you have any questions.

Bill Maier
Regional State Liaison Officer
USNRC Region 4
1600 East Lamar Boulevard
Arlington, TX 76011-4511
Tel: 817-200-1267
Fax: 817-200-1122
e-mail: bill.maier@nrc.gov

Outside of Scope

Outside of Scope

Outside of Scope

Outside of Scope

**Melfi, Jim**

| | |
|---|---|
| **From:** | Melfi, Jim |
| **Sent:** | Wednesday, May 08, 2013 7:53 AM |
| **To:** | Sanchez, Alfred; Allen, Don |
| **Cc:** | Azua, Ray; Bradley, Dan |
| **Subject:** | RE: ANO Update Week Ending Apr 26 2013.docx |
| **Attachments:** | ANO Update Week Ending May 10 2013.docx |

Fred, Don,

Attached, please find the DRAFT of the ANO weekly status report. The hi-lites noted on the report identify current updates and changes.

Please review and comment.

JIM MELFI

**Arkansas Nuclear One Dropped Stator Event**

**Week Ending May 10, 2013**

## Background

At 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 lift system 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. At the time of the event, Unit 1 was in a refueling outage. The reactor vessel head had been removed, fuel was in the reactor core, and the refueling cavity was flooded up with water level greater than 23 feet above the fuel. Unit 2 was operating at 100% power.

The failure of the lifting device and the dropped stator damaged electrical busses, resulting in a loss offsite power to Unit 1. Emergency diesel generators started and restored power to the vital busses. On Unit 2, the event caused a reactor coolant pump breaker to open, resulting in a Unit 2 reactor trip from 100% power. Later, due to fire water intrusion into Unit 2 switchgear (the fire main was damaged during the event), offsite power was lost to one of the vital busses due to the failure of a breaker. The associated emergency diesel generator started and restored power to the bus. The licensee declared a Notification of Unusual Event due to the failure (explosion) of the breaker.

(b)(5)

**Licensee Actions**

(b)(5)

**NRC Actions**

- The resident inspectors continue to monitor licensee actions.
- Augmented Inspection Team completed on site inspection and is documenting findings in a report. A public AIT exit meeting is scheduled for May 9.
- Residents, Region, and NRR reviewed the licensee's 50.59 evaluation to verify that the temporary offsite power source satisfies the Unit 1 Technical Specifications requirements prior to defueling the reactor.
- Region IV developed and implemented an inspection plan during the restart of Unit 2. Resident inspectors walked down firewater, instrument air, hydrogen, carbon dioxide, and electrical switchgear. Additionally, inspectors, monitored of key systems during and after startup, post trip review actions, and risk assessments for debris removal.
- NRC continues to respond to questions from the media. A press release was issued to announce the beginning of the augmented inspection. The public exit meeting for the AIT is scheduled for May 9th.

**NRC/OSHA Coordination**

- NRC staff and OSHA staff continue to coordinate activities and share information.
- Interactions with OSHA are being conducted consistent with guidance provided in Inspection Manual Chapter 1007 and the NRCV/OSHA Memorandum of Understanding dated October 21, 1988.

# Arkansas Nuclear One Dropped Stator Event

## Update As Of May 14, 2013

### Background

At 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 lift system 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. At the time of the event, Unit 1 was 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 fuel. Unit 2 was operating at 100% power.

The failure of the lifting device and the dropped stator damaged Unit 1 electrical busses, resulting in a loss of offsite power to Unit 1. Emergency diesel generators started and restored power to the vital busses. On Unit 2, the event caused a reactor coolant pump breaker to open, resulting in a Unit 2 reactor trip from 100% power. Later, due to fire water intrusion into Unit 2 switchgear (the fire main was damaged during the event), offsite power was lost to one of the Unit 2 vital busses due to the failure of a breaker. The associated emergency diesel generator started and restored power to the bus. The licensee declared a Notification of Unusual Event due to the failure (explosion) of the breaker.

(b)(5)

**Licensee Actions**

(b)(5)

**NRC Actions**

- The resident inspectors continue to monitor licensee actions.
- Augmented Inspection Team completed on site inspection and is documenting findings in a report. A public AIT exit meeting was held on May 9.
- Residents, Region, and NRR reviewed the licensee's 50.59 evaluation to verify that the temporary offsite power source satisfies the Unit 1 Technical Specifications requirements prior to defueling the reactor.
- Region IV developed and implemented an inspection plan during the restart of Unit 2. Resident inspectors walked down firewater, instrument air, hydrogen, carbon dioxide, and electrical switchgear. Additionally, inspectors monitored key systems during and after startup and reviewed the post trip actions and risk assessments for debris removal.
- NRC continues to respond to questions from the media. A press release was issued to announce the beginning of the augmented inspection and another to announce the public exit meeting for the AIT.

**NRC/OSHA Coordination**

- NRC staff and OSHA staff continue to coordinate activities and share information.
- Interactions with OSHA are being conducted consistent with guidance provided in Inspection Manual Chapter 1007 and the NRCV/OSHA Memorandum of Understanding dated October 21, 1988.

## Miller, Geoffrey

**From:** Miller, Geoffrey
**Sent:** Monday, May 20, 2013 1:52 PM
**To:** Loveless, David
**Subject:** RE: RISK QUESTIONS FOR ANO AIT
**Attachments:** Arkansas Event Questions for AIT.docx

David,

Attached are answers to the risk questions I had in my notes. I believe PBE was also working on this and may be able to provide additional info.

Thank you,

Geoff

**From:** Loveless, David
**Sent:** Tuesday, April 09, 2013 2:13 PM
**To:** Miller, Geoffrey
**Subject:** RISK QUESTIONS FOR ANO AIT

Geoff,

I'm attaching a list of questions that we (the "risky" guys) came up with to help model the risk of this event.

Please call if you have any concerns.

David
(b)(6)

1. What was the actual status of Electrical Distribution following event?
   - **6900 Volt Bus H2 was de-energized.**
   - **6900 Volt Bus H1 was energized.**
   - **4160 Volt Bus A2 was de-energized.**
   - **Safety related 4160 Volt Buses A3 and A4 were cross tied and supplied power via Non-safety related 4160 Volt bus A1.**
   - **480 Volt buses B5 and B6 were cross tied.**
   - **Green Train battery D06 had been disconnected from D02 bus.**
   - **D04 battery charger was supplied from Swing MCC B56 to provide power to Green Train DC bus D02.**
   - **B56 was aligned to B5.**

2. Where there any systems, trains or components out of service before the event?
   **Unit 1 was in the process of preparing for the planned outage and electrical alignments were in progress to support the activities of Green Train maintenance (see above)**

3. What is the pathway from reactor to ultimate heat sink in Unit 1?
   **2 DHR pumps avail (vital pwr)**
   **ICP pump supplied from London line avail for SFP cooling**

4. How much water is available in the Borated Water Storage Tanks?
   **4.8 feet = ~46k gal (~30kgal usable volume)**

5. Under what conditions could they gravity drain to the Unit 1 refueling pool?
   **Gravity feed was available between units**

6. How much water is available in the Boric Acid Tanks?
   **87% = 7.2 kgal**

7. How much water is available for transfer from the Unit 2 "VAN" system?
   **Unit 2 BAM system contained two 20kgal tanks**

8. How would you transfer the water in Question 7?
   **Transfer to BWST. BWST –> ctmt sump (vital powered vlvs) sump avail (water can flow past FME barriers)**

9. What was the failure mode of Bus A2? Energized? Deenergized?
   **Physical impact from above. A2 was de-energized.**

10. How could temporary power sources have been used if needed? **Temp diesels were used**
    a. Procedures
    b. Transformers required

c. Connection location

11. Are there currently direct connections (jumpers) to 480 volt buses (vital or nonvital)?

12. Please provide copies of the following procedures:
    a. . . .that required closing containment
    b. . . . that effected decay heat removal restoration
    c. . . . to respond to postulated loss of inventory
    d. . . . to make up to the refueling pool upon loss of DHR
    e. . . . to vent containment upon refueling pool bulk boiling

13. What was the potential for a loss of inventory event?
    a. What system is purifying the pool?
    b. What systems are connected to the pool?
    c. Could electrical faults have caused a drain?
    d. Were there any perturbations of the refueling pool level following the event? **No**

14. Were there any constraints on the timing of the heavy lift? **No**
    a. Could they have lifted before pool was full? **Verbally would not (not documented)**
    b. Could they have lifted after pool was drained? **Verbally no – not documented. Scheduled to lift new stator over switchgear while Green Train was unavailable (EDG and batteries tagged out).**

15. Could the heavy drop have affected Unit 2 more? **Not likely**
    a. Could the load have impacted Unit 2 side of turbine deck? **Not likely**
    b. Could the load have rolled into Unit 2 and done more damage? **Not likely**

16. Could flooding have been worse in Unit 2? **Possible, not likely**

17. Could the breaker spring issue identified earlier in the outage have affected event response? **I believe the answer was no – replacement with non-susceptible Siemens breakers was well underway. SRI has more details**
    a. Were feeder breakers from A1 to A3 or A2 to A4 degraded?
    b. Were any of the breakers on A3 or A4 degraded?

**Melfi, Jim**

| | |
|---|---|
| **From:** | Allen, Don |
| **Sent:** | Thursday, May 23, 2013 11:04 AM |
| **To:** | Kennedy, Kriss |
| **Cc:** | Bradley, Dan; Melfi, Jim; Azua, Ray; Tindell, Brian; Sanchez, Alfred; Schaup, William; Fairbanks, Abin |
| **Subject:** | ANO Update Week Ending May 24 2013 FINAL.docx |
| **Attachments:** | ANO Update Week Ending May 24 2013 FINAL.docx |

Kriss,

Attached is the final periodic update for ANO.

Stephen Pannier requested to be added to the distribution.

Don

# Arkansas Nuclear One Dropped Stator Event

## Week Ending May 24, 2013

**This is the last periodic update.**

**Additional updates will be provided for noteworthy milestones or events.**

### Background

At 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 lift system 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. At the time of the event, Unit 1 was 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 fuel. Unit 2 was operating at 100% power.

The failure of the lifting device and the dropped stator damaged Unit 1 electrical busses, resulting in a loss of offsite power to Unit 1. Emergency diesel generators started and restored power to the vital busses. On Unit 2, the event caused a reactor coolant pump breaker to open, resulting in a Unit 2 reactor trip from 100% power. Later, due to fire water intrusion into Unit 2 switchgear (the fire main was damaged during the event), offsite power was lost to one of the Unit 2 vital busses due to the failure of a breaker. The associated emergency diesel generator started and restored power to the bus. The licensee declared a Notification of Unusual Event due to the failure (explosion) of the breaker.

(b)(5)

- Vital and non-vital busses are energized via the unit auxiliary transformer. Startup Transformer 3 is operable for a fast transfer and is the normal offsite power source..
- Alternate AC Diesel Generator (Blackout Diesel) supply bus has been repaired and can now supply Unit 2 if needed
- Emergency diesel generators are in standby.
- Fire main is pressurized with damaged sections isolated. Fire watches are in place as needed.

**Licensee Actions**

(b)(5)

**NRC Actions**

- The resident inspectors continue to monitor licensee actions.

- Augmented Inspection Team completed on site inspection and is documenting findings in a report. A public AIT exit meeting was held on May 9.
- Residents, Region, and NRR reviewed the licensee's 50.59 evaluation to verify that the temporary offsite power source satisfies the Unit 1 Technical Specifications requirements prior to defueling the reactor.
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- NRC continues to respond to questions from the media. A press release was issued to announce the beginning of the augmented inspection and another to announce the public exit meeting.

**NRC/OSHA Coordination**

- NRC staff and OSHA staff continue to coordinate activities and share information.
- Interactions with OSHA are being conducted consistent with guidance provided in Inspection Manual Chapter 1007 and the NRCV/OSHA Memorandum of Understanding dated October 21, 1988.

**Miller, Geoffrey**

| | |
|---|---|
| **From:** | Kennedy, Kriss |
| **Sent:** | Thursday, May 23, 2013 5:18 PM |
| **To:** | Huyck, Doug; Allen, Don; Howell, Art; Lewis, Robert; Sanchez, Alfred; Melfi, Jim; Miller, Geoffrey; Fairbanks, Abin; Schaup, William; Leeds, Eric; Uhle, Jennifer; Dorman, Dan; McGinty, Tim; Hiland, Patrick; Nieh, Ho; Croteau, Rick; Roberts, Darrell; Reynolds, Steven; Blount, Tom; Clark, Jeff; Vegel, Anton; Pruett, Troy; Lund, Louise; Evans, Michele; Markley, Michael; Kalyanam, Kaly; Weil, Jenny; Howell, Linda; Pannier, Stephen; Hatfield, Gloria |
| **Subject:** | OUO - ARKANSAS NUCLEAR ONE WEEKLY UPDATE |
| **Attachments:** | ANO Final Update Week Ending May 24 2013.docx |

FYI - Please find attached an update of activities related to the March 31, 2013 event at Arkansas Nuclear One.

**This will be the final routine update of activities at ANO Unit 1.** We will communicate items of interest as they occur and updates as necessary.

Kriss

# Arkansas Nuclear One Dropped Stator Event

## Week Ending May 24, 2013

**This is the last periodic update.**

**Additional updates will be provided for noteworthy milestones or events.**

### Background

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(b)(5)

(b)(5)

**NRC Actions**

- The resident inspectors continue to monitor licensee actions.

- Augmented Inspection Team completed on site inspection and is documenting findings in a report. A public AIT exit meeting was held on May 9.
- Residents, Region, and NRR reviewed the licensee's 50.59 evaluation to verify that the temporary offsite power source satisfies the Unit 1 Technical Specifications requirements prior to defueling the reactor.
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- NRC continues to respond to questions from the media. A press release was issued to announce the beginning of the augmented inspection and another to announce the public exit meeting.

**NRC/OSHA Coordination**

- NRC staff and OSHA staff continue to coordinate activities and share information.
- Interactions with OSHA are being conducted consistent with guidance provided in Inspection Manual Chapter 1007 and the NRCV/OSHA Memorandum of Understanding dated October 21, 1988.

## Miller, Geoffrey

**From:** Allen, Don
**Sent:** Wednesday, June 05, 2013 11:32 AM
**To:** Miller, Geoffrey
**Subject:** ANO2013011-RP-GBM-(Don's comments).docx
**Attachments:** ANO2013011-RP-GBM-(Don's comments).docx

Geoff,

Attached is a markup with my comments. Other generic comments are:

Attachment 3 is not attached.

The water level in the reactor cavity is inconsistently described as above the core, above the reactor, above the fuel (actual level was 400' which is > 23 feet above the reactor vessel flange.) TS describes it as" >_23 feet above the top of the irradiated fuel seated in the reactor pressure vessel."

The crane is inconsistently described as temporary crane, temporary lifting rig, lifting rig, temporary overhead crane. Does OSHA have a concern with our description of the device?

Busses or Buses?

Don't use "#" in the name of equipment such as the startup transformer #3.

I think this is an outstanding inspection report! You have documented a lot of great issues.

Thank you,

Don

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

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 lifting rig 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 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 stator 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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,

Arthur T. Howell III
Regional Administrator

Dockets: 50-313; 50-368
Licenses: DPR-51; NPF-6

Enclosure: Inspection Report 05000313; 05000368/2013011
w/Attachments:
1. Supplemental Information
2. Sequence of Events
3. Augmented Inspection Team Charter (not attached!)

cc w/encl: Electronic Distribution

Bailey & Oliver Law Firm
3606 W Southern Hills Blvd
Suite 200
Rogers, AR 72758

Electronic distribution by RIV:
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Resident Inspector (William.Schaup@nrc.gov)
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## EXECUTIVE SUMMARY

An Augmented Inspection Team was chartered on April 5, 2013, to assess the facts and 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 temporary lifting rig 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 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 stator 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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**

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| 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<br>Russellville, Arkansas |
| Dates: | April 5 through May 9, 2013 |
| Inspectors: | G. Miller, Chief, Engineering Branch 2<br>A. Sanchez, Senior Resident Inspector, Project Branch E<br>J. Watkins, Reactor Inspector, Engineering Branch 2<br>S. Jones, Senior Reactor Systems Engineer, NRR<br>D. Loveless, Senior Reactor Analyst, Region IV |
| Approved By: | Donald B. Allen, Chief, Project Branch E<br>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 lifting rig 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 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 temporary lifting rig 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 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 stator 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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 ~~fuel~~ reactor vessel flange. Unit 2 was operating at 100 percent power with no plant evolutions in progress, no transmission switching events occurring, and no severe weather conditions.

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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 ~~busses~~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.

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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 parts 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 down Unit 2 to (b)(5) shutdown conditions.

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.

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, 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 ~~for~~ from start-up transformer 1 through bus A1 to the safety-related Red train bus A3. 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, buckling switchgear doors and tripping the supply breakers for bus A1 and resulting in a loss of offsite power to Unit 1.

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Following the loss of offsite power, both Unit 1 emergency diesel generators automatically started and loaded on 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 ~~5~~ 6 the decay heat removal pumps did not automatically restart following the emergency diesel generator starting and loading 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 ~~core~~ 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.

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Although not safety-related, the spent fuel pool cooling pumps are powered from safety-related 480 volt ~~busses~~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

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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 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 protection trip due to loss of reactor coolant system flow. The subsequent reactor trip involved an apparent failure of main feedwater regulating valve A to fully close.

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 based on the potential of an explosion having occurred in the electrical breaker cubicle at 10:33 a.m. An unresolved item associated with the emergency declaration is discussed in Section 6.0 of this report.

At the time of start-up 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, a loud water hammer was experienced between feedwater heaters 2E-5B and 2E-B6 on Unit 2. 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 start-up 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 was a complicated issue which resulted in a rapid rise in reactor coolant system pressure. Operators quickly responded and took appropriate actions to establish auxiliary spray, secure 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 installed an additional electric motor-driven fire pump 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 a non-credited offsite power source. 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 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, and 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 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 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 confirmed 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. Licensee assessment of damage was still in progress at the conclusion of the inspection.

The licensee performed the following inspections using Mechanical, Civil, Structural, Electrical, Fire Protection and Operations personnel:

- 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 05000313/2013-002; 05000368/2013-002, "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 dropped stator event and compared that response to the safety analyses. As part of their review, the team evaluated the electrical lineup 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~~bus H1 was energized and bus H2 was de-energized.
- 4160 Volt ~~Bus~~ bus A2 was de-energized.
- Safety related 4160 Volt ~~Buses~~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~~ train battery D06 was disconnected from bus D02.
- Battery charger D04 supplied from swing motor control center B56 ~~to~~ provided power to Green train DC bus D02.
- Motor control center B56 was aligned to bus B5.

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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 from protective relaying activation following the stator impact with the turbine building floor directly above the electrical equipment room. This was confirmed by observation of numerous relay targets in the bus A1 and A2 equipment with no indication of actual fault currents. Upon loss of the supply power bus A1 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 ~~to trip~~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.

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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 2P3A 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 A.

Water infiltration into the Unit 2 switchgear room from the ruptured fire water piping caused a bus fault in the 2A113 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~~ 3 bus lockout.

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.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 used to provide personnel access inside the steam generators for outage inspections. 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 ~~am~~ 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~~ 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.

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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 ~~compressor~~ compressed air

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.

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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 into the Unit 1 auxiliary building 317-foot elevation. 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 ~~asced~~ assessed the licensee's compensatory measures following the event. The compensatory measures assessed included required operator and security actions for damaged equipment and barriers.

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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 require restarting.

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 London 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 London 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 ~~asses~~ 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, and the team conducted interviews with operators and emergency preparedness personnel

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b. Observations

The team concluded the identified Emergency Action Level for small explosion inside the protected area (HU4) 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 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 Management Team (ORAT) 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 ORAT 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 repower 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 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 (b)(5) fuel in the reactor vessel, and no fuel movement in progress), the Shutdown Operations Protection Plan (Procedure 1015.048, Change No. 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 (TS) 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 concluded 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, which was under the load path for the stator movement.

The heavy load handling checklist in Attachment 9.1 to procedure (b)(5) included the following possible risk mitigation actions for the protected equipment:

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- 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 heavy lift of the stator was treated as an infrequently performed test or evolution (IPTE), which entailed enhanced communication of the lift; 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 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 with fuel still in the reactor vessel.

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 ~~structure~~ 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.

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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 Management ??? 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.

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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. An unresolved item associated with the licensee's 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.

.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 standalone 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

SRA INPUT

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 analyst 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), $1.1 \times 10^{-6}$, 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 quantified as $1.3 \times 10^{-5}$.

For Unit 1, the analyst used Figure 8 from Appendix G, Attachment 2, to assess the risk of the event. The licensee informed the analyst that one of the breakers required to power the vital ~~bussesbuses~~ from the alternate ac diesel generator was not available because of potential damage from the event. Therefore, the analyst calculated the probability of an emergency power supply system demand failure at $4.49 \times 10^{-3}$, 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 analyst 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 derived using the SPAR as $3.63 \times 10^{-1}$. The analyst used a screening value of 0.1 for the probability of alternative strategies failure leading to core damage. The resulting CCDP was $1.6 \times 10^{-4}$, which was in the range for an augmented inspection team using Management Directive 8.3, "NRC Incident Investigation Program."

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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.

## 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

| Number | Title | Revision |
|---|---|---|
| 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 |

| Number | Title | Revision |
|---|---|---|
| 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 |
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| 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

| Number | Title | Revision |
|---|---|---|
| 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 |
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| 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 |
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| OP-1015-.037 | Post Transient Review | 10 |
| OP-1903.010 | Emergency Action Level Classification | 46 |

CALCULATIONS

| Number | Title | Revision |
|---|---|---|
| 27619-C1 | Heavy Lift Gantry Calculation – ANO Stator Replacement Project | 0 |

MISCELLANEOUS DOCUMENTS

| Number | Title | Revision/Date |
|---|---|---|
| 1R24 | ANO Unit 1 Outage Schedule (Green Train and Stator) | April 9, 2013 |
| | AIS Manual of Steel Construction | 14th Ed. |
| ASME NQA-1 | Quality Assurance Requirements for Nuclear Facility Applications | 2012 |
| EN-LI-100 | Process Applicability Determination for EC43686 Attachment 9.1 | 13 |
| | 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 | |
| FS-009 | Firewater System Rupture Tagout | |

VENDOR MATERIALS

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

MODIFICATIONS

| Number | Title | Revision |
|---|---|---|
| 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-2-2013-0736 | | |

**ATTACHMENT 2**

**SEQUENCE OF EVENTS**

| Date/Time | Event Description |
|---|---|
| **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 begins |
| 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. |
| 7:47 a.m. | Unit 1 Operators secured high pressure injection pump P-36C per procedure OP-1104.002 Supplement 8. |
| 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 (Remove # throughout) 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."<br><br>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.

Unit 1 entered Personnel Emergency due to Unit 1 Stator drop. STA commenced Personnel Emergency Checklist – Shift Manager (1903.023B). Ambulances have been dispatched based upon preliminary damage estimates.

Unit 2 entered Personnel Emergency due to Unit 1 Stator drop.

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 receives reports from Unit 2 that Unit 2 Instrument Air compressors are functioning properly. Unit 1 instrument air compressors are 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 requests that electricians be dispatched to inspect A1 and A2 switchgear while using extreme caution. 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 is closed

8:11 a.m. Ambulances arriving onsite are directed to respond to the "breezeway" area north of the Unit 2 Turbine building near the freight elevator.

Unit 1 completed setting 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 remains out of service.

8:14 a.m. Unit 1 decay heat trains A and B are 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 1 all outside watch-standers are accounted for.

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 reports that reactor building sump level is 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 reports 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 reports 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. | Unit 1 SM rescinded the order to set containment closure based on restoration of Decay Heat Cooling with reactor coolant system temperatures stable. Further reports from plant operators indicate that damage from the temporary crane collapse is limited to the train bay and turbine deck area. The fuel transfer canal level and spent fuel pool level remain stable.<br><br>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 are in service being powered from emergency diesel generators #1 and #2, respectively | |
| 8:34 a.m. | Unit 1 reports that all Siemens personnel are accounted for. | |
| 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. Verified valves entered in Component Deviation Log. | |
| 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.<br><br>Unit 2 pump 2P-7A discharge valves have been aligned to their normal positions from their EFAS actuated positions. Unit 2 exited TS 3.0.3. | |
| 8:52 a.m. | Unit 1 Shift Manager reports that 1 fatality has been reported. | |
| 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 records temporary fire pump secured to aid in depressurizing the fire main. | |

9:23 a.m. Unit 2 Startup #3 Transformer locked out. Startup #2 is supplying buses 2A1 and 2A3. Bus 2A2 is de-energized and bus 2A4 is powered from Emergency Diesel Generator #2. All Reactor Coolant Pumps are secured. Auxiliary feedwater pump 2P75 tripped due to startup transformer #2 load shed. Loss of spent fuel pool cooling due to pump 2P-40B loss of power. Instrument air compressors are off 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 has been knocked open (unable to determine which breaker at this time). There is light smoke from the back of one breaker in bus 2A1 but no fire. There is 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 intermediate cooling water pump P-33C 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 Fire and Explosion abnormal operating procedure.

9:58 a.m. Unit 2 operators entered Loss of Instrument Air abnormal operating procedure.

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|---|---|
| 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 receives a report of significant water hammer from the East Heater Deck. Operators are investigating. |
| 10:15 a.m. | Unit 2 spent fuel pool cooling pump 2P-40A started. |
| 10:23 a.m. | As a contingency, two Hale diesel driven fire pumps (on trailers) are 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 Unit 1 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 declared Notification of Unusual Event (NUE) due to damage to Switchgear 2A1 and Startup #3 transformer lockout. |
| 10:36 a.m. | Unit 2 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 notifications for Notification of Unusual Event. |
| 11:33 a.m. | Unit 2 energized bus 2B2 from bus 2B1 so that both instrument air compressors could be placed in service. |
| 11:40 a.m. | Unit 2 started Instrument Air compressor 2C-27B. Both Unit 2 Instrument Air compressors are 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 reports that decay heat removal pump P-34B is functioning properly, however there is 1 inch of water standing in decay heat vault B. Decay heat vault room drains have been verified closed. Unit 1 operators walked down elevation 317 along with site management. Firewater leaking into elevation 317 has stopped and level is stable in decay heat vault B. Level does not have the potential to impact safety related equipment. |
| 11:59 a.m. | Unit 2 Completed 4 hour report to OSHA for part 29. |
| 12:20 p.m. | Unit 2 restored letdown flow with charging pump 2P-36C. |
| 12:42 p.m. | Unit 2 letdown is in Auto. |

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|---|---|
| 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. |
| 1:00 p.m. | Unit 2 started charging pump 2P-36A. |
| 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 is 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. |
| 1:30 p.m. | Unit 2 breaker 2A113 is reported faulted with visual damage to breaker cubicle. |
| 1:31 p.m. | Unit 2 Control room received a report that bus 2A9 is degraded; therefore, the Alternate AC Diesel Generator (AACDG) is 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 has been 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. |
| 1:59 p.m. | Unit 2 reactivity balance calculation completed. Shutdown margin is satisfied. |
| 2:09 p.m. | Unit 2 operators reset EFAS #1 and #2. |
| 2:10 p.m. | A third Hale diesel driven fire pump (on trailer) is 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 cool-down. |
| 2:31 p.m. | Unit 1 operators exited TRM 3.7.6 for Spent fuel Cooling |

| | |
|---|---|
| 2:50 p.m. | Unit 1 operators exited procedure 1203.024, "Loss of Instrument Air." |
| 2:56 p.m. | Unit 1 operators commenced pumping turbine building trench via a temporary pump to the oily water separator via the startup transformer #1 drain pit. |
| 3:03 p.m. | Unit 1 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. | Unit 2 all Unit 1 and Unit 2 Deluge Sprinkler Systems (open sprinkler heads) have been isolated using Configuration Control Records U2-FS-DELUGE ISOLATING FOR RESTORE and U1-FS-FILLING FIREWATER SYSTEM in preparation for fire suppression system restoration. |
| 3:58 p.m. | Unit 2 operators closed both main steam isolation valves. |
| 4:15 p.m. | Unit 2 operators started charging pump 2P-36B and secured charging pump 2P-36C. |
| 5:00 p.m. | Unit 1 outage risk is Red due to not meeting Electrical System requirements for SOPP Condition 2. Unit 1 is unable to utilize off-site power. Both emergency diesel generators are in service supplying safety system loads. |
| 11:35 p.m. | Unit 2 AACDG 4160V output breaker has been racked out per procedure OP-2104.037 Exhibit 2 Section 2 to protect bus 2A9 for Unit 1 and Unit 2. |
| 11:54 p.m. | Unit 1 emergency temporary modification installation authorized by engineering director designee and the Unit 1 shift manager for aligning power from startup transformer #1 to buses A3 and A4 via crosstie 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**

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|---|---|
| 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. |

## Miller, Geoffrey

**From:** Miller, Geoffrey
**Sent:** Wednesday, June 05, 2013 3:26 PM
**To:** Uselding, Lara
**Cc:** Dricks, Victor
**Subject:** DRAFT ANO AIT report
**Attachments:** ANO2013011-RP-GBM-DRAFT.docx

Lara,

Attached is a DRAFT version of the ANO AIT report we discussed earlier this week. I expect the final version to be signed out on Friday. You will receive an electronic copy of the final report. Please let me know if you have questions.

Thank you,

Geoff

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

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 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 removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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,

Arthur T. Howell III
Regional Administrator

Dockets: 50-313; 50-368
Licenses: DPR-51; NPF-6

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

cc w/encl: Electronic Distribution

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ROPreports

DOCUMENT NAME: R:\REACTORS\ANO\2013\ANO2013011-RP-GBM.docx **ML**

| | | | | | |
|---|---|---|---|---|---|
| SUNSI Rev Compl. | ☑Yes ☐ No | ADAMS | ☑Yes ☐ No | Reviewer Initials | GBM |
| Publicly Avail. | ☑Yes ☐ No | Sensitive | ☐Yes ☑ No | Sens. Type Initials | GBM |

| | | | | | |
|---|---|---|---|---|---|
| AIT Lead | AIT Member | AIT Member | AIT Member | RIV:SRA | C:DRP/E |
| GMiller | ASanchez | JWatkins | SJones | DLoveless | DBAllen |
| **/RA/** | | **/RA/** | **E-GBM** | **/RA/** | **E-GBM** |
| 6/4/13 | | 6/4/13 | 6/5/13 | 6/5/13 | 6/5/13 |
| D:DRP | DRA | RA | | | |
| KMKennedy | RLewis | ATHowell | | | |
| | | | | | |
| | | | | | |

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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 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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**

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| 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<br>Russellville, Arkansas |
| Dates: | April 5 through May 9, 2013 |
| Inspectors: | G. Miller, Chief, Engineering Branch 2<br>A. Sanchez, Senior Resident Inspector, Project Branch E<br>J. Watkins, Reactor Inspector, Engineering Branch 2<br>S. Jones, Senior Reactor Systems Engineer, NRR<br>D. Loveless, Senior Reactor Analyst, Region IV |
| Approved By: | Donald B. Allen, Chief, Project Branch E<br>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 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 crane components struck the Unit 2 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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 with no plant evolutions in progress, no transmission switching events occurring, and no severe weather conditions.

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 parts 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 down Unit 2 to (b)(5) shutdown conditions.

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.

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 start-up 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 loaded on 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 loading 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 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 protection trip due to loss of reactor coolant system flow. The subsequent reactor trip involved an apparent failure of main feedwater regulating valve A to fully close.

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 start-up 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 start-up 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 installed an additional electric motor-driven fire pump 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 a non-credited offsite power source. 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 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, and 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 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 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 confirmed 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. Licensee assessment of damage was still in progress at the conclusion of the inspection.

The licensee performed the following inspections using Mechanical, Civil, Structural, Electrical, Fire Protection and Operations personnel:

- 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 05000313/2013-002; 05000368/2013-002, "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 dropped stator event 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 from protective relaying activation following the stator impact with the turbine building floor directly above the electrical equipment room. This was confirmed by observation of numerous relay targets in the bus A1 and A2 equipment with no indication of actual fault currents. Upon loss of the supply power bus A1 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 2P3A 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 A.

Water infiltration into the Unit 2 switchgear room from the ruptured fire water piping caused a bus fault in the 2A113 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 used to provide personnel access inside the steam generators for outage inspections. 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 into the Unit 1 auxiliary building 317-foot elevation. 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 require restarting.

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 London 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 London 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, and the team conducted interviews with operators and emergency preparedness personnel

b. Observations

The team concluded the identified Emergency Action Level for small explosion inside the protected area (HU4) 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 Management Team (ORAT) 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 ORAT 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 repower 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, Change No. 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

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 with fuel still in the reactor vessel.

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. An unresolved item associated with the licensee's 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.

.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), $1.1 \times 10^{-6}$, 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 $1.3 \times 10^{-5}$.

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 $4.49 \times 10^{-3}$, 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 $3.63 \times 10^{-1}$. 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 $1.6 \times 10^{-4}$, 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

| Number | Title | Revision |
|---|---|---|
| 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 |

| Number | Title | Revision |
|---|---|---|
| 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

| Number | Title | Revision |
|---|---|---|
| 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

| Number | Title | Revision |
|---|---|---|
| 27619-C1 | Heavy Lift Gantry Calculation – ANO Stator Replacement Project | 0 |

MISCELLANEOUS DOCUMENTS

| Number | Title | Revision/Date |
|---|---|---|
| 1R24 | ANO Unit 1 Outage Schedule (Green Train and Stator) | April 9, 2013 |
| | AIS Manual of Steel Construction | 14th Ed. |
| ASME NQA-1 | Quality Assurance Requirements for Nuclear Facility Applications | 2012 |
| EN-LI-100 | Process Applicability Determination for EC43686 Attachment 9.1 | 13 |
| | 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 | |
| FS-009 | Firewater System Rupture Tagout | |

VENDOR MATERIALS

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

MODIFICATIONS

| Number | Title | Revision |
|---|---|---|
| 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-2-2013-0736 | | |

## ATTACHMENT 2

## SEQUENCE OF EVENTS

| Date/Time | Event Description |
|---|---|
| **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 begins |
| 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. |
| 7:47 a.m. | Unit 1 Operators secured high pressure injection pump P-36C per procedure OP-1104.002 Supplement 8. |
| 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."<br><br>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.

Unit 1 entered Personnel Emergency due to Unit 1 Stator drop. STA commenced Personnel Emergency Checklist – Shift Manager (1903.023B). Ambulances have been dispatched based upon preliminary damage estimates.

Unit 2 entered Personnel Emergency due to Unit 1 Stator drop.

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 receives reports from Unit 2 that Unit 2 Instrument Air compressors are functioning properly. Unit 1 instrument air compressors are 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 requests that electricians be dispatched to inspect A1 and A2 switchgear while using extreme caution. 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 is closed

8:11 a.m. Ambulances arriving onsite are directed to respond to the "breezeway" area north of the Unit 2 Turbine building near the freight elevator.

Unit 1 completed setting 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 remains out of service.

8:14 a.m. Unit 1 decay heat trains A and B are 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 1 all outside watch-standers are accounted for.

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 reports that reactor building sump level is 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 reports 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 reports 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. Unit 1 SM rescinded the order to set containment closure based on restoration of Decay Heat Cooling with reactor coolant system temperatures stable. Further reports from plant operators indicate that damage from the temporary crane collapse is limited to the train bay and turbine deck area. The fuel transfer canal level and spent fuel pool level remain 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 are in service being powered from emergency diesel generators 1 and 2, respectively

8:34 a.m. Unit 1 reports that all Siemens personnel are accounted for.

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. Verified valves entered in Component Deviation Log.

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 have been aligned to their normal positions from their EFAS actuated positions. Unit 2 exited TS 3.0.3.

8:52 a.m. Unit 1 Shift Manager reports that 1 fatality has been reported.

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 records temporary fire pump secured to aid in depressurizing the fire main.

| | |
|---|---|
| 9:23 a.m. | Unit 2 Startup 3 Transformer locked out. Startup 2 is supplying buses 2A1 and 2A3. Bus 2A2 is de-energized and bus 2A4 is powered from Emergency Diesel Generator 2. All Reactor Coolant Pumps are secured. Auxiliary feedwater pump 2P75 tripped due to startup transformer 2 load shed. Loss of spent fuel pool cooling due to pump 2P-40B loss of power. Instrument air compressors are off due to startup transformer 3 lockout.<br><br>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 has been knocked open (unable to determine which breaker at this time). There is light smoke from the back of one breaker in bus 2A1 but no fire. There is 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 intermediate cooling water pump P-33C reported ready to be energized from the London Line.<br><br>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.<br><br>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 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 receives a report of significant water hammer from the East Heater Deck. Operators are investigating.

10:15 a.m. Unit 2 spent fuel pool cooling pump 2P-40A started.

10:23 a.m. As a contingency, two Hale diesel driven fire pumps (on trailers) are 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 Unit 1 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 declared Notification of Unusual Event (NUE) due to damage to Switchgear 2A1 and Startup 3 transformer lockout.

10:36 a.m. Unit 2 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 notifications for Notification of Unusual Event.

11:33 a.m. Unit 2 energized bus 2B2 from bus 2B1 so that both instrument air compressors could be placed in service.

11:40 a.m. Unit 2 started Instrument Air compressor 2C-27B. Both Unit 2 Instrument Air compressors are 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 reports that decay heat removal pump P-34B is functioning properly; however there is 1 inch of water standing in decay heat vault B. Decay heat vault room drains have been verified closed. Unit 1 operators walked down elevation 317 along with site management. Firewater leaking into elevation 317 has stopped and level is stable in decay heat vault B. Level does not have the potential to impact safety related equipment.

11:59 a.m. Unit 2 Completed 4 hour report to OSHA for part 29.

12:20 p.m. Unit 2 restored letdown flow with charging pump 2P-36C.

12:42 p.m. Unit 2 letdown is in Auto.

(b)(7)(C)

| | |
|---|---|
| 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. |
| 1:00 p.m. | Unit 2 started charging pump 2P-36A. |
| 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 is 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. |
| 1:30 p.m. | Unit 2 breaker 2A113 is reported faulted with visual damage to breaker cubicle. |
| 1:31 p.m. | Unit 2 Control room received a report that bus 2A9 is degraded; therefore, the Alternate AC Diesel Generator (AACDG) is 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 has been 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. |
| 1:59 p.m. | Unit 2 reactivity balance calculation completed. Shutdown margin is satisfied. |
| 2:09 p.m. | Unit 2 operators reset EFAS 1 and 2. |
| 2:10 p.m. | A third Hale diesel driven fire pump (on trailer) is 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 cool-down. |
| 2:31 p.m. | Unit 1 operators exited TRM 3.7.6 for Spent fuel Cooling |

| | |
|---|---|
| 2:50 p.m. | Unit 1 operators exited procedure 1203.024, "Loss of Instrument Air." |
| 2:56 p.m. | Unit 1 operators commenced pumping turbine building trench via a temporary pump to the oily water separator via the startup transformer 1 drain pit. |
| 3:03 p.m. | Unit 1 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. | Unit 2 all Unit 1 and Unit 2 Deluge Sprinkler Systems (open sprinkler heads) have been isolated using Configuration Control Records U2-FS-DELUGE ISOLATING FOR RESTORE and U1-FS-FILLING FIREWATER SYSTEM in preparation for fire suppression system restoration. |
| 3:58 p.m. | Unit 2 operators closed both main steam isolation valves. |
| 4:15 p.m. | Unit 2 operators started charging pump 2P-36B and secured charging pump 2P-36C. |
| 5:00 p.m. | Unit 1 outage risk is Red due to not meeting Electrical System requirements for SOPP Condition 2. Unit 1 is unable to utilize off-site power. Both emergency diesel generators are in service supplying safety system loads. |
| 11:35 p.m. | Unit 2 AACDG 4160V output breaker has been racked out per procedure OP-2104.037 Exhibit 2 Section 2 to protect bus 2A9 for Unit 1 and Unit 2. |
| 11:54 p.m. | Unit 1 emergency temporary modification installation authorized by engineering director designee and the Unit 1 shift manager for aligning power from startup transformer 1 to buses A3 and A4 via crosstie 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. |

## Melfi, Jim

**From:** Kennedy, Kriss
**Sent:** Friday, June 28, 2013 8:23 AM
**To:** Leeds, Eric; Howell, Art; Uhle, Jennifer; Dorman, Dan; McGinty, Tim; Hiland, Patrick; Nieh, Ho; Croteau, Rick; Roberts, Darrell; Reynolds, Steven; Blount, Tom; Clark, Jeff; Vegel, Anton; Pruett, Troy; Miller, Geoffrey; Allen, Don; Melfi, Jim; Lund, Louise; Evans, Michele; Markley, Michael; Kalyanam, Kaly; Fairbanks, Abin; Weil, Jenny; Tindell, Brian; Young, Matt; Pannier, Stephen; Bradley, Dan
**Subject:** UPDATE ON ARKANSAS NUCLEAR ONE ACTIVITIES
**Attachments:** ANO Update Week Ending June 28 2013.docx

FYI - Please find attached an update of activities related to the March 31, 2013 event at Arkansas Nuclear One.

Kriss

**Arkansas Nuclear One Dropped Stator Event**

**Week Ending June 28, 2013**

**This is a periodic update for noteworthy milestones or events.**

## Background

At 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 lift system 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. At the time of the event, Unit 1 was 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 fuel. Unit 2 was operating at 100% power.

The failure of the lifting device and the dropped stator damaged Unit 1 electrical busses, resulting in a loss of offsite power to Unit 1. Emergency diesel generators started and restored power to the vital busses. On Unit 2, the event caused a reactor coolant pump breaker to open, resulting in a Unit 2 reactor trip from 100% power. Later, due to fire water intrusion into Unit 2 switchgear (the fire main was damaged during the event), offsite power was lost to one of the Unit 2 vital busses due to the failure of a breaker. The associated emergency diesel generator started and restored power to the bus. The licensee declared a Notification of Unusual Event due to the failure (explosion) of the breaker.

(b)(5)

(b)(5)

**NRC Actions**

- The resident inspectors continue to monitor licensee actions.
- The Augmented Inspection Team completed on site inspection and issued an inspection report (ML13158A242). A public AIT exit meeting was held on May 9.
- NRC reviewed the licensee's 50.59 evaluation to verify that the temporary offsite power sources satisfied the Unit 1 Technical Specifications requirements prior to defueling the Unit 1 reactor.
- Region IV developed and implemented an inspection plan prior to the restart of Unit 2. Resident inspectors walked down firewater, instrument air, hydrogen, carbon dioxide, and electrical switchgear. Additionally, inspectors monitored key systems during and after startup and reviewed the post trip actions and risk assessments for debris removal.
- Region IV will complete inspection of key items prior to the restart of Unit 1.
- Region IV plans to conduct a followup inspection, prior to restart of Unit 1, of the unresolved items identified during the augmented inspection.
- Region IV inspectors are reviewing the licensee's root cause evaluation for the failed lifting device and corrective actions that the licensee has implemented prior to moving the replacement stator into the turbine building.

**NRC/OSHA Coordination**

- NRC staff and OSHA staff continue to coordinate activities and share information.
- Interactions with OSHA are being conducted consistent with guidance provided in Inspection Manual Chapter 1007 and the NRCV/OSHA Memorandum of Understanding dated October 21, 1988.

## Melfi, Jim

**From:** Bradley, Dan
**Sent:** Wednesday, July 03, 2013 8:32 AM
**To:** Tindell, Brian
**Cc:** Azua, Ray; Melfi, Jim; Fairbanks, Abin; Willoughby, Leonard; Allen, Don
**Subject:** FW: ANO in the news today

Brian,

I passed it along and talked to Victor (he is aware). There are a few other press items today (like Palo Verde's NOUE) that he is working through first.

Thank you for the info.

(b)(6)

-Dan

Dan Bradley
Project Engineer - Division of Reactor Projects Branch E
U.S. NRC Region IV
dan.bradley@nrc.gov
817-200-1506

**From:** Bradley, Dan
**Sent:** Wednesday, July 03, 2013 8:26 AM
**To:** Dricks, Victor; Uselding, Lara
**Cc:** Kennedy, Kriss; Fuller, Karla
**Subject:** FW: ANO in the news today

Victor and Lara,

Sounds like some response here is required.

Several news articles are quoting a lawsuit (from the mother of the individual killed during the ANO stator drop) which implies NRC culpability. Obviously, we aren't going to venture into the legal side of it but I think the news side deserves correction.

-Dan

Dan Bradley
Project Engineer - Division of Reactor Projects Branch E
U.S. NRC Region IV
dan.bradley@nrc.gov
817-200-1506

**From:** Tindell, Brian
**Sent:** Wednesday, July 03, 2013 8:07 AM
**To:** Azua, Ray
**Cc:** Bradley, Dan; Melfi, Jim; Fairbanks, Abin; Willoughby, Leonard; Allen, Don
**Subject:** ANO in the news today

Ray,

In case you missed it, this was in the "NRC in the News Today". The sad thing is that it implicates the NRC in his death. The article makes it sound like the NRC rushed Entergy to move the stator, forcing them to go with a low bidder that did a bad job. Should we talk to OPA about contacting them?

(b)(4)

Thanks,
Brian

**Baca, Bernadette**

**From:** Tindell, Brian
**Sent:** Tuesday, July 09, 2013 9:12 AM
**To:** Azua, Ray
**Subject:** RE: Answers to ANO Questions

No problem. He called out here yesterday.

Can you give me a call when you get a chance? Abin said you had some questions. Thanks

**From:** Azua, Ray
**Sent:** Tuesday, July 09, 2013 8:51 AM
**To:** Tindell, Brian
**Subject:** RE: Answers to ANO Questions

Brian,

I am just curious, when did Kriss provided you with these questions. Thanks.

Ray

**From:** Tindell, Brian
**Sent:** Monday, July 08, 2013 5:36 PM
**To:** Kennedy, Kriss
**Cc:** Allen, Don; Azua, Ray; Fairbanks, Abin
**Subject:** Answers to ANO Questions

(b)(5)

Thanks,
Brian

## Baca, Bernadette

**From:** Tindell, Brian
**Sent:** Tuesday, July 16, 2013 5:27 PM
**To:** Tindell, Brian; Willoughby, Leonard
**Cc:** Fairbanks, Abin; Hatfield, Gloria; Allen, Don
**Subject:** RE: ANO AIT Followup - Baseline

Leonard,

The external flooding procedure is 71111.01, not 71111.06. Sorry.

Thanks,
Brian

**From:** Tindell, Brian
**Sent:** Tuesday, July 16, 2013 5:23 PM
**To:** Willoughby, Leonard
**Cc:** Fairbanks, Abin; Hatfield, Gloria; Allen, Don
**Subject:** ANO AIT Followup - Baseline

Leonard,

(b)(5)

(b)(5)

## Latta, Robert

**From:** MOSHER, NATALIE B <NMOSHER@entergy.com>
**Sent:** Friday, July 19, 2013 9:08 AM
**To:** Latta, Robert
**Cc:** Willoughby, Leonard; Hall, Michael; PYLE, STEPHENIE L
**Subject:** RE: ANO - AIT FOLLOWUP INSPECTION

Bob, See status below. Thanks, Natalie

(b)(5)

(b)(5)

(b)(5)

## Latta, Robert

**From:** Willoughby, Leonard
**Sent:** Tuesday, July 30, 2013 6:39 PM
**To:** Melfi, Jim; Latta, Robert; Okonkwo, Nnaerika
**Subject:** FW: AIT FOLLOWUP

Gentleman,

See requested information from David Loveless.

Leonard

(b)(5)

## Melfi, Jim

**From:** Melfi, Jim
**Sent:** Tuesday, August 06, 2013 12:53 PM
**To:** Latta, Robert
**Subject:** AIT.finding2.writeup.docx
**Attachments:** AIT.finding2.writeup.docx

(b)(5)

DOCS REVIEWED

ANO-1 Stator Recovery Slides, Restart Challenge Presentation 1, Structural & Mechanical Damage Assessment & Repair

ANO-1 Stator Recovery Slides, Restart Challenge Presentation 2, Electrical Damage Assessment

ANO-1 Stator Recovery Slides, Restart Challenge Presentation 3, Electrical Testing

**Melfi, Jim**

(b)(5)

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(b)(5)

## Latta, Robert

**From:** Latta, Robert
**Sent:** Wednesday, October 02, 2013 2:40 PM
**To:** Willoughby, Leonard
**Subject:** ANO Docs Reviewed list. 1.docx
**Attachments:** ANO Docs Reviewed list. 1.docx

Leonard,

I hope you are feeling better. The attached file contains a listing of the documents I reviewed during our followup inspection at ANO. Please let me know if you have any questions.

Bob

(b)(5)



Attachment

(b)(5)



Attachment

(b)(5)

(b)(5)

## Melfi, Jim

**From:** Werner, Greg
**Sent:** Thursday, October 24, 2013 11:13 AM
**To:** Weerakkody, Sunil
**Cc:** Miller, Geoffrey; Pruett, Troy; Kennedy, Kriss; Loveless, David; Davis, Marlone; Tindell, Brian; Young, Matt; Fairbanks, Abin; Melfi, Jim; Bloodgood, Michael
**Subject:** RE: ANO SDP Status Update

Thanks Sunil. I do understand that other activities may impact, just keep us informed. Looking to keep the momentum moving in the completion direction and developing SERP packages to go along with the completion of those items. As much as our branch can, we are trying to work in parallel vs. series in order to get some of these items moving.

Appreciate your rapid response!!
Greg

**From:** Weerakkody, Sunil
**Sent:** Thursday, October 24, 2013 10:28 AM
**To:** Werner, Greg
**Cc:** Miller, Geoffrey; Pruett, Troy; Kennedy, Kriss; Loveless, David; Davis, Marlone; Tindell, Brian; Young, Matt; Fairbanks, Abin; Melfi, Jim; Bloodgood, Michael
**Subject:** RE: ANO SDP Status Update

Greg,

We are working to a goal of providing a preliminary Phase III on Item 3(a), and 4 by 11/15.

In addition to performing the Phase IIIs for 3(a) and (4), we will have to peer review results of other four SDPs that Dave performs (1, 2a, 2b, and 3b), in the event they turn out to be GTG.
There are other uncertainties (e.g., depending upon how you phrase the PDs for 1, 2(a), 2(b), and 3(b), our Phase III analyses may have to change.

I will set up a call to discuss.

*Sunil D. Weerakkody*
*Branch Chief, PRA Operational Support Branch*
*Division of Risk Assessment*
*Office of Nuclear Reactor Regulation*
*US Nuclear Regulatory Commission*

*Tel: 301-415-2870*
*Email: sunil.weerakkody@nrc.gov*

(b)(5)

(b)(5)

(b)(5)

(b)(5)

## Baca, Bernadette

**From:** Tindell, Brian
**Sent:** Wednesday, October 30, 2013 1:53 PM
**To:** Fairbanks, Abin; Young, Matt; Hatfield, Gloria
**Subject:** FW: Abnormal Occurrence Report for ANO Stator Drop
**Attachments:** Abnormal Occurrence Report for ANO Stator Drop.docx

FYI.

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**From:** Werner, Greg
**Sent:** Wednesday, October 30, 2013 1:24 PM
**To:** Bloodgood, Michael
**Cc:** Melfi, Jim; Tindell, Brian; Maier, Bill
**Subject:** Abnormal Occurrence Report for ANO Stator Drop

Mike,

Bill Maier is supposed be sending us what he considers as a good (golden) example of an input for the Abnormal Occurrence Report. He is also going to summarize MD 8.1 criteria and what our input should look like.

I started a skeleton of the AOR (see attached file).

Greg

On March 31, 2013, during transfer of the 600 ton Arkansas Nuclear One (ANO) Unit 1 main generator stator, the main stator fell approximately 30 feet into the train bay and caused structural damage of the Unit 1 turbine building. For ANO Unit 1, which was in a refueling outage, this drop caused a loss of offsite power. With the loss of offsite power to Unit 1, both Unit 1 emergency diesel generators started and loaded onto their electrical busses. Decay heat removal was quickly restored. The Unit 1 emergency diesel generators supplied power to the vital electrical busses for over 5 days.

Arkansas Nuclear One Unit 2 experienced a reactor trip from 100 percent power after the falling stator and crane components caused a loss of reactor coolant pump B. About 1 ½ hours later, water from a damaged fire suppression system piping caused a breaker failure in ANO Unit 2, resulting in loss of power to one vital bus and a Notification of Unusual Event. The associated emergency diesel generators for Unit 2 started and supplied vital loads. Both units remained stable.

One worker was killed and eight others were injured when the main generator stator fell.

On April 8, 2013, the Nuclear Regulatory Commission commenced an Augmented Inspection Team (AIT) assessment of the circumstances surrounding the March 31, 2013, loss of offsite power for ANO Unit 1, and the reactor trip and subsequent Notification of Unusual Event for ANO Unit 2. The basis for the conducting an AIT was ????? (summarize the MD 8.3) The AIT was onsite (dates) and completed their inspection on (date), with x unresolved items identified. The AIT report was issued on June 7, 2013, MLxxxxx.

(b)(5)

## Werner, Greg

**From:** Werner, Greg
**Sent:** Wednesday, October 30, 2013 7:19 AM
**To:** Melfi, Jim; Bloodgood, Michael
**Cc:** Werner, Greg
**Subject:** FW: ANO SDP Status Update

**Importance:** High

Jim,

E-mail David and see if you verbal answers gave him what he needed. If not, please ask him for specifics.

Jim and Mike,

FYI -- For that AAC SDP I spoke to Geoff yesterday, (b)(6) sick Monday and Tuesday. He was supposed to have something on Friday, but did not.

Greg

(b)(5)

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(b)(5)

Greg

## Baca, Bernadette

**From:** Werner, Greg
**Sent:** Thursday, October 31, 2013 8:06 AM
**To:** Miller, Geoffrey
**Cc:** Bloodgood, Michael; Tindell, Brian; Melfi, Jim; Loveless, David; Werner, Greg; Pruett, Troy; Kennedy, Kriss
**Subject:** RE: ANO SDP Status Update

**Importance:** High

Great!! I will have Jim get with David to work on the Appendix M basis and a realistic date for completion of the Appendix M basis. Once we get a sound basis, we can brief senior management on our recommendation and path forward.

Greg

---

**From:** Miller, Geoffrey
**Sent:** Thursday, October 31, 2013 7:44 AM
**To:** Werner, Greg
**Cc:** Bloodgood, Michael; Tindell, Brian; Melfi, Jim; Loveless, David
**Subject:** RE: ANO SDP Status Update

Greg,

I recommend moving forward with Appendix M.

From the App M Basis section - this sounds like a case where the uncertainties associated with the SDP risk evaluation are too broad for decision-making, thus the risk evaluation process could take considerably more time than is necessary or reasonable.

David can provide technical support to the branch in answering the deterministic questions as needed.

Thank you,

Geoff

---

**From:** Werner, Greg
**Sent:** Thursday, October 31, 2013 7:04 AM
**To:** Miller, Geoffrey
**Cc:** Bloodgood, Michael; Tindell, Brian; Melfi, Jim; Loveless, David
**Subject:** RE: ANO SDP Status Update

Good Morning Geoff,

(b)(5)

(b)(5)

**From:** Werner, Greg
**Sent:** Wednesday, October 30, 2013 7:19 AM
**To:** Melfi, Jim; Bloodgood, Michael
**Cc:** Werner, Greg
**Subject:** FW: ANO SDP Status Update
**Importance:** High

Jim,

E-mail David and see if you verbal answers gave him what he needed. If not, please ask him for specifics.

Jim and Mike,

FYI – For that AAC SDP I spoke to Geoff yesterday, David (b)(6) He was supposed to have something on Friday, but did not.

Greg

(b)(5)

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**Latta, Robert**

**From:** Melfi, Jim
**Sent:** Friday, November 08, 2013 12:39 PM
**To:** Latta, Robert
**Subject:** FW: ANO Report
**Attachments:** ANO Poast-AIT Rpt (Body) 20131028.docx

Bob

Can you look at your sections.

If you could, please develop a PIM for your findings.

Also, Leonard wants you to put in the Tmod you looked at for the temp fire pump as a bullet item in section 1R18.

JIM

**From:** Willoughby, Leonard
**Sent:** Friday, November 08, 2013 9:34 AM
**To:** Melfi, Jim
**Subject:** ANO Report

Jim,

I finally have an internet connection that is something better than a snails pace. I will be sending some updates to you but they will be in the form of a cut an paste to try and make it easier.

Will you be putting the report in a folder on the "S" drive where I can reach? I need to fill in my sections which requires me to find them first. I'm not panicking yet.

Leonard

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## Miller, Geoffrey

**From:** Miller, Geoffrey
**Sent:** Wednesday, November 20, 2013 12:31 PM
**To:** Kennedy, Kriss; Allen, Don
**Cc:** Blount, Tom
**Subject:** ANO Presentation Feedback Request
**Attachments:** ANO_AIT.pptx

Don/Kriss,

I attached a draft PowerPoint presentation for the Region I inspector counterpart meeting on Lessons Learned from the ANO stator drop AIT. The slides contain mainly talking points; I'll be happy to discuss the words that go along with the points if you'd like. I would appreciate any feedback on additions/deletions/revisions. I plan to discuss this with Marc on Friday, and I'm scheduled to give the presentation in RI on 12/3.

Thank you very much,

Geoff

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## Miller, Geoffrey

**From:** Jones, Steve
**Sent:** Wednesday, June 05, 2013 11:19 AM
**To:** Miller, Geoffrey; Sanchez, Alfred
**Cc:** Allen, Don; Karl, Tracy
**Subject:** RE: ANO AIT Report for Concurrence
**Attachments:** ANO2013011-RP-SRJ Comments-DRAFT.docx

Geoff,

I concur with comments as indicated in the attached file.

Thanks,

Steve

**From:** Miller, Geoffrey
**Sent:** Tuesday, June 04, 2013 4:01 PM
**To:** Sanchez, Alfred; Jones, Steve
**Cc:** Allen, Don; Karl, Tracy
**Subject:** ANO AIT Report for Concurrence

Gents,

Sorry for the short turnaround on this – could you please review the attached report for concurrence asap? This needs to be signed out by Friday. Please send me any comments/revisions.

Thank you,

Geoff

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

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 lifting rig 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 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 stator 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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,

Arthur T. Howell III
Regional Administrator

Dockets: 50-313; 50-368
Licenses: DPR-51; NPF-6

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

cc w/encl: Electronic Distribution

Bailey & Oliver Law Firm
3606 W Southern Hills Blvd
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Rogers, AR 72758

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ROPreports

DOCUMENT NAME: R:\REACTORS\ANO\2013\ANO2013011-RP-GBM.docx **ML**

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|---|---|---|---|---|---|
| SUNSI Rev Compl. | ☑Yes ☐ No | ADAMS | ☑Yes ☐ No | Reviewer Initials | GBM |
| Publicly Avail. | ☑Yes ☐ No | Sensitive | ☐Yes ☑ No | Sens. Type Initials | GBM |

| | | | | | |
|---|---|---|---|---|---|
| AIT Lead | AIT Member | AIT Member | AIT Member | RIV:SRA | C:DRP/E |
| GMiller | ASanchez | JWatkins | SJones | DLoveless | DBAllen |
| | | /RA/ | | | |
| | | 6/4/13 | | | |
| D:DRP | DRA | RA | | | |
| KMKennedy | RLewis | ATHowell | | | |
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## EXECUTIVE SUMMARY

An Augmented Inspection Team was chartered on April 5, 2013, to assess the facts and 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 temporary lifting rig 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 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~~ hoisting equipment attached to the stator ~~on~~ 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently 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<br>Russellville, Arkansas |
| Dates: | April 5 through May 9, 2013 |
| Inspectors: | G. Miller, Chief, Engineering Branch 2<br>A. Sanchez, Senior Resident Inspector, Project Branch E<br>J. Watkins, Reactor Inspector, Engineering Branch 2<br>S. Jones, Senior Reactor Systems Engineer, NRR<br>D. Loveless, Senior Reactor Analyst, Region IV |
| Approved By: | Donald B. Allen, Chief, Project Branch E<br>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 lifting rig 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 implemented using Inspection Procedure 93800, "Augmented Inspection Team." The inspection was conducted by a team of inspectors from the NRC's Region IV office 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 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 temporary lifting rig 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 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 stator on~~ crane components struck the Unit 2 turbine deck, ~~caused~~ causing electrical breakers to open~~,~~ and 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, removing one offsite power source from Unit 2 and causing one of the Unit 2 emergency diesel generators to start to restore power to its associated safety-related switchgear. Operators subsequently declared a Notification of Unusual Event, terminating it after taking corrective actions to stabilize the plant's power supplies.

  **Comment [srj1]:** Crane components struck the Unit 2 turbine deck, based on the video.

  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 8, 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 fuel. Unit 2 was operating at 100 percent power with no plant evolutions in progress, no transmission switching events occurring, and no severe weather conditions

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 busses. 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 parts 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 down Unit 2 to [redacted] shutdown conditions. (b)(5)

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.

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.

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 ~~for~~ from start-up transformer 1 through bus A1 to the safety-related Red train bus A3. 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 ~~buckling~~ buckled switchgear doors and ~~tripping~~ tripped the supply breakers for bus A1, ~~and~~ which ~~resulting~~ resulted in a loss of offsite power to Unit 1.

Comment [sr12]: Do you want to note the initial condition of Bus A2? My recollections that it was removed from service as part of the Green Train outage.

Following the loss of offsite power, both Unit 1 emergency diesel generators automatically started and loaded on 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 5, the decay heat removal pumps ~~did not~~ were not aligned to automatically restart following the emergency diesel generator starting and loading 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 core 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 busses 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 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 protection trip due to loss of reactor coolant system flow. The subsequent reactor trip involved an apparent failure of main feedwater regulating valve A to fully close.

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 ~~based at~~ 10:33 a.m. An unresolved item associated with the emergency declaration is discussed in Section 6.0 of this report.

At the time of start-up 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, loud water hammer was experienced between feedwater heaters 2E-5B and 2E-B6 on Unit 2. 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.

Comment [srj3]: The significance of this water hammer should be described or the comment should be deleted.

The lock out of start-up 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 was a complicated issue which resulted in a rapid rise in reactor coolant system pressure. Operators quickly ~~responded and took appropriate actions to~~ 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.

Comment [srj4]: I recommend describing that the temporary fire pump provided cooling water to a chiller. Otherwise, readers may assume that the full capacity (2500 gpm) was flowing thorough the rupture for over an hour.

Description. The licensee installed an additional electric motor-driven fire pump 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 a non-credited offsite power source. 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 67 minutes after 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, and 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 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 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 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 confirmed 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. Licensee assessment of damage was still in progress at the conclusion of the inspection.

The licensee performed the following inspections using Mechanical, Civil, Structural, Electrical, Fire Protection and Operations personnel:

- 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 05000313/2013-002; 05000368/2013-002, "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 dropped stator event and compared that response to the safety analyses. As part of their review, the team evaluated the electrical lineup 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 effected 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 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 from protective relaying activation following the stator impact with the turbine building floor directly above the electrical equipment room. This was confirmed by observation of numerous relay targets in the bus A1 and A2 equipment with no indication of actual fault currents. Upon loss of the supply power bus A1 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 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 2P3A 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 A.

Water infiltration into the Unit 2 switchgear room from the ruptured fire water piping caused a bus fault in the 2A113 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 used to provide personnel access inside the steam generators for outage inspections. 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 both air compressors, was lost. Without an air supply, the nozzle dams began to lose pressure. At approximately 9:30 am 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 compressor 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 into the Unit 1 auxiliary building 317-foot elevation. 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 assed 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 require restarting.

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 London 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 London 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 asses the licensee's actions in this

area, the team performed a detailed review of operator logs, the computerized sequence of events and condition reports, and the team conducted interviews with operators and emergency preparedness personnel

b. Observations

The team concluded the identified Emergency Action Level for small explosion inside the protected area (HU4) 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 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 Management Team (ORAT) 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 ORAT 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 repower 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 not installed prior to beginning the stator lift.~~

**Comment [SRJ3]:** Please confirm. The outage schedule indicates the temp mods (Alternate Power for ICW Pumps) were scheduled to be installed on March 27th for ICW pumps P-33B and P-33C, well before the scheduled and actual start of the stator lift. Also, the event sequence above states: "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." This sequence would not allow time for installation of the temp mod, only placing it into service.

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 (b)(5) fuel in the reactor vessel, and no fuel movement in progress), the Shutdown Operations Protection Plan (Procedure 1015.048, Change No. 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 (TS) 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 concluded 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, which was under the load path for the stator movement.

The heavy load handling checklist in Attachment 9.1 to procedure (b)(5) 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 heavy lift of the stator was treated as an infrequently performed test or evolution (IPTE), which entailed enhanced communication of the lift; 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 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 with fuel still in the reactor vessel.

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 structure 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 Management 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, 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. An unresolved item associated with the licensee's 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.

.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 standalone 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

SRA INPUT

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 analyst 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), $1.1 \times 10^{-6}$, 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 quantified as $1.3 \times 10^{-5}$.

For Unit 1, the analyst used Figure 8 from Appendix G, Attachment 2, to assess the risk of the event. The licensee informed the analyst that one of the breakers required to power the vital busses from the alternate ac diesel generator was not available because of potential damage from the event. Therefore, the analyst calculated the probability of an emergency power supply system demand failure at $4.49 \times 10^{-3}$, 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 analyst 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 derived using the SPAR as $3.63 \times 10^{-1}$. The analyst used a screening value of 0.1 for the probability of alternative strategies failure leading to core damage. The resulting CCDP was $1.6 \times 10^{-4}$, 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.

## 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. Chemivec | 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

| Number | Title | Revision |
|---|---|---|
| 11405-E-1 | Main One Line Diagram P & ID | 49 |
| 27819-001 | 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 |

| Number | Title | Revision |
|---|---|---|
| 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

| Number | Title | Revision |
|---|---|---|
| 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

| Number | Title | Revision |
|---|---|---|
| 27619-C1 | Heavy Lift Gantry Calculation – ANO Stator Replacement Project | 0 |

MISCELLANEOUS DOCUMENTS

| Number | Title | Revision/Date |
|---|---|---|
| 1R24 | ANO Unit 1 Outage Schedule (Green Train and Stator) | April 9, 2013 |
| | AIS Manual of Steel Construction | 14th Ed. |
| ASME NQA-1 | Quality Assurance Requirements for Nuclear Facility Applications | 2012 |
| EN-LI-100 | Process Applicability Determination for EC43686 Attachment 9 1 | 13 |
| | 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 | |
| FS-009 | Firewater System Rupture Tagout | |

VENDOR MATERIALS

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

MODIFICATIONS

| Number | Title | Revision |
|---|---|---|
| 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-346586 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-2013-00868 | ANO-2-2013-0736 | | |

## ATTACHMENT 2

## SEQUENCE OF EVENTS

| Date/Time | Event Description |
|---|---|
| **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 begins |
| 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. |
| 7:47 a.m. | Unit 1 Operators secured high pressure injection pump P-36C per procedure OP-1104.002 Supplement 8. |
| 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."<br><br>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.

Unit 1 entered Personnel Emergency due to Unit 1 Stator drop. STA commenced Personnel Emergency Checklist – Shift Manager (1903.023B). Ambulances have been dispatched based upon preliminary damage estimates.

Unit 2 entered Personnel Emergency due to Unit 1 Stator drop

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 receives reports from Unit 2 that Unit 2 Instrument Air compressors are functioning properly. Unit 1 instrument air compressors are 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 requests that electricians be dispatched to inspect A1 and A2 switchgear while using extreme caution. 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 is closed

8:11 a.m. Ambulances arriving onsite are directed to respond to the "breezeway" area north of the Unit 2 Turbine building near the freight elevator.

Unit 1 completed setting 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 remains out of service.

8:14 a.m. Unit 1 decay heat trains A and B are 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 1 all outside watch-standers are accounted for.

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 reports that reactor building sump level is stable. Unit 1 closed generator hydrogen bank #3 isolation valve H2-101 and verified all other generator hydrogen bank outlets closed per procedure OP-1108.002 exhibit D. Generator hydrogen secured to both Unit 1 and Unit 2.

8:23 a.m. Unit 1 operator reports 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 reports 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.

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| 8:31 a.m. | Unit 1 SM rescinded the order to set containment closure based on restoration of Decay Heat Cooling with reactor coolant system temperatures stable. Further reports from plant operators indicate that damage from the temporary crane collapse is limited to the train bay and turbine deck area. The fuel transfer canal level and spent fuel pool level remain stable.<br><br>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 are in service being powered from emergency diesel generators #1 and #2, respectively |
| 8:34 a.m | Unit 1 reports that all Siemens personnel are accounted for. |
| 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. Verified valves entered in Component Deviation Log |
| 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 the London line.<br><br>Unit 2 pump 2P-7A discharge valves have been aligned to their normal positions from their EFAS actuated positions. Unit 2 exited TS 3.0.3. |
| 8:52 a.m. | Unit 1 Shift Manager reports that 1 fatality has been reported. |
| 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 records temporary fire pump secured to aid in depressurizing the fire main. |

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| 9:23 a.m. | Unit 2 Startup #3 Transformer locked out. Startup #2 is supplying buses 2A1 and 2A3. Bus 2A2 is de-energized and bus 2A4 is powered from Emergency Diesel Generator #2. All Reactor Coolant Pumps are secured. Auxiliary feedwater pump 2P75 tripped due to startup transformer #2 load shed Loss of spent fuel pool cooling due to pump 2P-40B loss of power. Instrument air compressors are off due to startup transformer #3 lockout.<br><br>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 has been knocked open (unable to determine which breaker at this time). There is light smoke from the back of one breaker in bus 2A1 but no fire. There is 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 intermediate cooling water pump P-33C reported ready to be energized from the London Line.<br><br>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.<br><br>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 Fire and Explosion abnormal operating procedure. |
| 9:58 a.m | Unit 2 operators entered Loss of Instrument Air abnormal operating procedure. |

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| 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 receives a report of significant water hammer from the East Heater Deck. Operators are investigating. |
| 10:15 a.m. | Unit 2 spent fuel pool cooling pump 2P-40A started. |
| 10:23 a.m. | As a contingency, two Hale diesel driven fire pumps (on trailers) are 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 Unit 1 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 declared Notification of Unusual Event (NUE) due to damage to Switchgear 2A1 and Startup #3 transformer lockout. |
| 10:36 a.m. | Unit 2 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 notifications for Notification of Unusual Event. |
| 11:33 a.m. | Unit 2 energized bus 2B2 from bus 2B1 so that both instrument air compressors could be placed in service. |
| 11:40 a.m. | Unit 2 started Instrument Air compressor 2C-27B. Both Unit 2 Instrument Air compressors are 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 reports that decay heat removal pump P-34B is functioning properly, however there is 1 inch of water standing in decay heat vault B. Decay heat vault room drains have been verified closed. Unit 1 operators walked down elevation 317 along with site management. Firewater leaking into elevation 317 has stopped and level is stable in decay heat vault B. Level does not have the potential to impact safety related equipment |
| 11:59 a.m. | Unit 2 Completed 4 hour report to OSHA for part 29. |
| 12:20 p.m. | Unit 2 restored letdown flow with charging pump 2P-36C. |
| 12:42 p.m. | Unit 2 letdown is in Auto. |

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| 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. |
| 1:00 p.m. | Unit 2 started charging pump 2P-36A. |
| 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 is 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. |
| 1:30 p.m. | Unit 2 breaker 2A113 is reported faulted with visual damage to breaker cubicle. |
| 1:31 p.m. | Unit 2 Control room received a report that bus 2A9 is degraded; therefore, the Alternate AC Diesel Generator (AACDG) is 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 has been 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. |
| 1:59 p.m. | Unit 2 reactivity balance calculation completed. Shutdown margin is satisfied. |
| 2:09 p.m. | Unit 2 operators reset EFAS #1 and #2. |
| 2:10 p.m. | A third Hale diesel driven fire pump (on trailer) is 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 cool-down. |
| 2:31 p.m. | Unit 1 operators exited TRM 3.7.6 for Spent fuel Cooling |

| | |
|---|---|
| 2:50 p.m. | Unit 1 operators exited procedure 1203.024, "Loss of Instrument Air." |
| 2:56 p.m. | Unit 1 operators commenced pumping turbine building trench via a temporary pump to the oily water separator via the startup transformer #1 drain pit. |
| 3:03 p.m. | Unit 1 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. | Unit 2 all Unit 1 and Unit 2 Deluge Sprinkler Systems (open sprinkler heads) have been isolated using Configuration Control Records U2-FS-DELUGE ISOLATING FOR RESTORE and U1-FS-FILLING FIREWATER SYSTEM in preparation for fire suppression system restoration. |
| 3:58 p.m. | Unit 2 operators closed both main steam isolation valves. |
| 4:15 p.m. | Unit 2 operators started charging pump 2P-36B and secured charging pump 2P-36C. |
| 5:00 p.m. | Unit 1 outage risk is Red due to not meeting Electrical System requirements for SOPP Condition 2. Unit 1 is unable to utilize off-site power. Both emergency diesel generators are in service supplying safety system loads. |
| 11:35 p.m. | Unit 2 AACDG 4160V output breaker has been racked out per procedure OP-2104.037 Exhibit 2 Section 2 to protect bus 2A9 for Unit 1 and Unit 2. |
| 11:54 p.m. | Unit 1 emergency temporary modification installation authorized by engineering director designee and the Unit 1 shift manager for aligning power from startup transformer #1 to buses A3 and A4 via crosstie 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. |

**Baca, Bernadette**

**From:** Sigmon, Rebecca on behalf of NRR_DIRS_IOEB Resource
**Sent:** Friday, June 14, 2013 11:57 AM
**To:** NRR_DIRS_IOEB Resource
**Subject:** Periodic Operating Experience (POE 2013-05)

Outside of Scope

Outside of Scope

Outside of Scope

Outside of Scope

Refer NRR

# ANO-1 Crane Collapse and Stator Drop - UPDATE

*Steve Pannier*

As discussed in POE 2013-03, an industrial accident at Arkansas Nuclear One Unit-1 on March 31, 2013 resulted in a fatality, loss of offsite power for Unit 1, a Unit 2 reactor trip, and structural damage to the Unit 1 turbine building and fire suppression system. The Augmented Inspection Team report issued on June 7, 2013, identifies ten Unresolved Items (URIs), which will be looked at in detail during follow-up inspections. These include:

- Extent of the structural impact to Unit 1 and Unit 2;
- Licensee control of modifications associated with a temporary fire pump;
- Adequacy of compensatory measures following the fire water system rupture;
- Procedural controls associated with air supply to steam generator nozzle dams;
- Effectiveness of turbine building flood barriers;
- Maintenance practices for the Unit 2 main feedwater regulating valve;
- Timeliness of the emergency action level declaration;
- Adequacy of shutdown risk management;
- Station documentation of crane load testing and related engineering evaluations; and
- Root causes and corrective actions associated with the crane failure.

The URI regarding shutdown risk management noted that the licensee had not incorporated the risks associated with the stator lift into the overall outage risk management process. At the time of the drop, offsite power for Unit 1 was being supplied through a non-safety related bus located under the load path, but all emergency diesel generators (EDGs) were available. Had the drop occurred later in the outage when the stator was scheduled to be re-installed, only one EDG would have been available to provide power to Unit 1.

Unit 2 returned to power on April 28, 2013. At Unit 1, which remains defueled, the licensee has completed debris removal and structural repairs. Further repairs to the turbine deck and electrical buses damaged during the drop are still needed prior to restart. (*See OpE COMM*)

(b)(4)

Outside of Scope

Outside of Scope

Outside of Scope

Outside of Scope

Outside of Scope

## Fairbanks, Abin

**From:** Tindell, Brian
**Sent:** Wednesday, October 23, 2013 3:29 PM
**To:** Fairbanks, Abin; Young, Matt; Hatfield, Gloria
**Subject:** FW: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

FYI

**From:** Werner, Greg
**Sent:** Wednesday, October 23, 2013 3:24 PM
**To:** Weerakkody, Sunil
**Cc:** Tindell, Brian; Melfi, Jim; Bloodgood, Michael; Mitman, Jeffrey; Miller, Geoffrey; Werner, Greg
**Subject:** RE: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

(b)(5)

Thanks,
Greg

**From:** Weerakkody, Sunil
**Sent:** Wednesday, October 23, 2013 7:17 AM
**To:** Werner, Greg
**Subject:** RE: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

On these commitments, we are batting 100% on timeliness. I want to keep it that way. Let me know if you sense any kind of trouble.

**From:** Werner, Greg
**Sent:** Wednesday, October 23, 2013 8:16 AM
**To:** Weerakkody, Sunil
**Subject:** RE: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

Thanks

**From:** Weerakkody, Sunil
**Sent:** Wednesday, October 23, 2013 7:15 AM
**To:** Werner, Greg
**Cc:** Mitman, Jeffrey; Miller, Geoffrey; Bloodgood, Michael; Melfi, Jim; Tindell, Brian
**Subject:** RE: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

Greg,

I have asked Jeff Mitman to proposed a revised formal commitment. Since the final deliverable is peer-reviewed version, we Jeff Circle may commit to providing a preliminary draft followed by the final.

Thanks

*Sunil D. Weerakkody*
*Branch Chief, PRA Operational Support Branch*

*Division of Risk Assessment*
*Office of Nuclear Reactor Regulation*
*US Nuclear Regulatory Commission*

*Tel: 301-415-2870*
*Email: sunil.weerakkody@nrc.gov*

**From:** Werner, Greg
**Sent:** Tuesday, October 22, 2013 5:21 PM
**To:** Weerakkody, Sunil
**Cc:** Mitman, Jeffrey; Miller, Geoffrey; Bloodgood, Michael; Melfi, Jim; Tindell, Brian; Werner, Greg
**Subject:** RE: Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

Good Afternoon Sunil,

To follow-up on our call, as I indicated, I'm a Branch Chief and am taking over Waterford and ANO from Don Allen. Would like to get a realistic date on when Jeff believes he will complete the ANO Unit 1 shutdown Phase 3 SDP. Since the onsite inspection was completed in July, senior management (and I as well) would like to get an idea of a date when the SDP will be completed so we can move forward on dispositioning of this issue. (b)(5)

(b)(5)

Thanks in advance!
Greg Werner
DRP Branch E Branch Chief
817-200-1156

**From:** Weerakkody, Sunil
**Sent:** Wednesday, September 11, 2013 2:12 PM
**To:** Allen, Don
**Cc:** Mitman, Jeffrey; Loveless, David; Pruett, Troy; Kennedy, Kriss; Clark, Jeff; Lee, Samson; Giitter, Joseph
**Subject:** Request for your consideration: Phase 3 SDP on ANO Unit 1 Shutdown Event

Don,

This is a follow-up to our phone call this afternoon.

For events that occur during shutdown, NRR\DRA must provide the region with a peer reviewed SDP. In setting the regional timeline on this SDP (SERPs etc..), please assume that we plan to provide our Phase III analyses to the RGN IV by 10/30/2013.

Due to a variety of issues (e.g., diverting our resources to other priorities such as Fukushima related work, NFPA 805, and Prioritization Study per a COMSECY), we will have a significant hardship delivering our input earlier than 10/30.

Let's continue to dialogue, if this suggested date is not acceptable to RGN IV mgmt..

Thank you!

*Sunil D. Weerakkody*
*Branch Chief, PRA Operational Support Branch*
*Division of Risk Assessment*
*Office of Nuclear Reactor Regulation*
*US Nuclear Regulatory Commission*

*Tel: 301-415-2870*
*Email: sunil.weerakkody@nrc.gov*

**Werner, Greg**

**From:** Weerakkody, Sunil
**Sent:** Thursday, October 24, 2013 8:20 AM
**To:** Werner, Greg
**Cc:** Miller, Geoffrey; Pruett, Troy; Kennedy, Kriss; Loveless, David; Davis, Marlone; Mitman, Jeffrey; Tindell, Brian; Young, Matt; Fairbanks, Abin; Bloodgood, Michael; Melfi, Jim
**Subject:** RE: ANO SDP Status Update

Refer

Greg,

Thank you!

I will meet with Jeff Mitman today and get back to you by COB Friday.

*Sunil D. Weerakkody*
*Branch Chief, PRA Operational Support Branch*
*Division of Risk Assessment*
*Office of Nuclear Reactor Regulation*
*US Nuclear Regulatory Commission*

*Tel: 301-415-2870*
*Email: sunil.weerakkody@nrc.gov*

(b)(5)

(b)(5)

Greg

## Torbey, Andrea

**From:** Campbell, Stephen Acting DIRS/IRIB Branch Chief
**Sent:** Monday, April 01, 2013 3:23 PM
**To:** Campbell, Stephen; Cartwright, William; Cauffman, Christopher; Curran, Bridget; Gamberoni, Marsha; Isom, James; Klett, Audrey; Kobetz, Timothy; Levasseur, Gabriel; Lewin, Aron; Telson, Ross; White, Chasity
**Subject:** FW: ANO Load Drop
**Attachments:** Arkansas Nuclear One Event Summary (3-31-13).docx; Stator Drop Pictures 001.jpg; Stator Drop Pictures 006.jpg; Stator Drop Pictures 008.jpg; Stator Drop Pictures 013.jpg; Stator Drop Pictures 023.jpg; Stator Drop Pictures 031.jpg

FYI

Stephen J. Campbell,
Senior Reactor Systems Engineer
NRR/DIRS/IRIB
Office - O7D7
Mail Stop - O7C2A
E-mail: stephen.campbell@nrc.gov | Office: (301) 415-3353 | NRC Cell (b)(6) | Fax: (301) 415-3061|

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**From:** Jones, Steve NRR/DE/Branch of Plant/Sr. Reactor Systems Engineer (Heavy Loads Specialist)
**Sent:** Monday, April 01, 2013 3:21 PM
**To:** Casto, Greg
**Cc:** Davis, Jack; Dennig, Robert; Jackson, Christopher; Kalyanam, Kaly; Campbell, Stephen; Howe, Allen
**Subject:** FW: ANO Load Drop

Release

Greg,

I've attached some internal information on the load drop from DORL.

The NRC heavy load handling program is limited to loads that, if dropped, could interrupt essential safe shutdown functions without consideration of an additional single failure, or load drops that could directly affect the safe storage of fuel. That is, if the load drop could have simultaneously damaged all means of accomplishing a safety function, the lift would have then been within the scope of the heavy load handling program.

From the attached event summary, attached pictures, and plant arrangement drawings in the FSAR, this load handling evolution was not within the typical scope of plant heavy load handling programs. The load handling area was well away from irradiated fuel and other safety-related systems and components. The load drop resulted in loss of a single off-site power supply, but other power supplies (including on-site power supplies from the EDGs) were available. Therefore, essential safety functions could continue to be satisfied following the load drop. However, the load handling activity would still be subject to risk management through the maintenance rule (10 CFR 50.65(a)(4)). Maintenance rule applicability to heavy loads activities was noted in Section 1 of NEI 08-05, "Industry Initiative on Control of Heavy Loads," (ADAMS Accession No. ML082180666) which the NRC endorsed in 2008.

The lift used a temporary internal structure with strand-jack hoists to lift and position the stator for transportation out of the turbine building. The overhead turbine building crane was not used, possibly because the lift would exceed the rating of the crane and/or the building structure. The drop apparently resulted from structural failure of the temporary lift structure or the supporting structure.

The electrical failure apparently resulted from a secondary effect of the drop. According to the event summary, the switchgear explosion resulted from a fire header rupture that wet the switchgear. The loss of this offsite source caused a temporary loss of decay heat removal to the Unit 1 reactor, which was in the refueling mode at high water level, and caused the Unit 2 reactor to trip from a loss of power to at least one reactor coolant pump. Other support loads were apparently lost on Unit 2 as indicated by its use of atmospheric steam dumps for decay heat removal. However, essential loads were recovered on the diesel generators promptly after the loss of the offsite source.

From a regulatory perspective, the degree of administrative control of this activity would be expected to be low based on the minimal threat to essential safety functions and critical components. The only concern I have is the recurrence of unexpected system interactions. In this case, the rupture of the fire header affecting non-safety switchgear was an unexpected interaction. Many electrical components are located in areas of the plant that are not well protected from water accumulation.

Steve

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**From:** Kalyanam, Kaly NRR / DORL / Project Manager for ANO
**Sent:** Monday, April 01, 2013 11:54 AM
**To:** Jones, Steve
**Cc:** Markley, Michael
**Subject:** RE: ANO Load Drop

Steve,

Please refer any inquiries you have from external parties regarding the ANO event to the RIV DRP BC or Public Affairs Officer. The photos routed for information today are part of RIV inspection and are pre-decisional for decisions regarding the MD 8.3 inspection determination going forward. Please maintain control of these photos and let the flow of information to external parties come from RIV. Do not release these photos in response to inquiries.

Mike

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**From:** Jones, Steve
**Sent:** Monday, April 01, 2013 11:25 AM
**To:** Kalyanam, Kaly
**Subject:** ANO Load Drop

Kaly,

I'm being contacted about the weekend load drop at ANO by NRR Management. Please forward any information and pictures you may have on the event, and appropriate Regional contacts.

Thanks,

Steve

Steven R. Jones
Sr. Reactor Systems Engineer
NRR/DSS/SBPB
301-415-2712

**Arkansas Nuclear One Event Summary**

Information is current as of 1730 CST, March 31, 2013

At 7:50 a.m. on 3/31/2013, Arkansas Nuclear One Unit 1 experienced a loss of offsite power and Unit 2 experienced a reactor trip. While lifting and transferring the Unit 1 main generator stator to the train bay, the lift system failed, falling on to the turbine deck and into the train bay. This resulted in damage to the turbine building and train bay, including damage to electrical buses supplying offsite power to Unit 1, and damage to fire suppression piping.

The failure and fall of the lifting system resulted in eight (8) injuries, including one fatality. Six individuals have been treated and released; two remain hospitalized.

At the time of the event, Unit 1 was in a refueling outage with all fuel in the reactor vessel, the reactor cavity was flooded up, and both trains of decay heat removal system were in service. With loss of offsite power, both Unit 1emergency diesel generators started and loaded their respective buses. Decay heat removal was quickly restored. Unit 1 is stable with no offsite power available due to damage to the non vital electrical buses, both EDGs are powering the vital busses and the decay heat removal system is operating and providing decay heat removal to the reactor vessel. A rough calculation from the licensee estimates (worst case scenario for all four EDGs running at full load) eight (8) days of fuel available on site (safety-related and non-safety related sources).

At the time of the event, Unit 2 was at 100 percent power. Damage to the train bay caused a loss of electrical power to Unit 2 B reactor coolant pump. The RCP trip caused the Unit 2 reactor to trip. All equipment operated as expected except for one feedwater regulating valve which did not fully close. Operators initiated the emergency feedwater system to maintain steam generator levels.

At 9:22 a.m., offsite power to Unit 2 from startup transformer 3 was lost, the Unit 2 EDG 2 started and energized train B, and train A remained energized from offsite power. The electrical breaker for startup transformer 3 was later found to have failed from water intrusion from the broken fire main, causing a possible explosion in the breaker cubicle.

At 10:44 a.m., the site declared a Notification of Unusual Event due to Emergency Action Level HU4, explosion in the protected area. The site remains in an Unusual Event. All emergency response facilities are manned and operational. EOF has emergency direction function.

Unit 2 is stable in Mode 3, on natural circulation. Offsite power is powering the train A vital bus and EDG 2 is powering the train B vital bus. Decay heat is being removed using the atmospheric relief valves and emergency feedwater. Unit 2 is cooling down to Mode 4 on natural circulation. The licensee wants to place the Unit on decay heat removal.

The fire suppression system in Unit 1 is shutdown due to damage to the fire water piping. Portions of the Unit 2 fire water system were damaged, and have been isolated. Temporary

Rp 1essa

Release

pumps (2- b.5.b pumps) have been positioned to provide fire water, if needed. A London fire truck is also inside the PA ready to respond. Fire watches are active in auxiliary buildings (both Units).

The licensee's priorities are to restore electrical redundancy to Unit 1 and assess damage.

The resident inspectors responded to the site and are monitoring licensee actions. The NRC remains in Normal Mode of response.

There has been media interest in the event. The licensee has issued a press release.

Pa 164 SC