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

March 24, 2014

EA-14-008

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 FOLLOW-UP INSPECTION REPORT 05000313/2013012 AND 05000368/2013012; PRELIMINARY RED AND YELLOW FINDINGS

Dear Mr. Browning:

On February 10, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed the Augmented Inspection Follow-up Inspection at the Arkansas Nuclear One, Units 1 and 2. The enclosed inspection report presents the results of this inspection. A final exit briefing was conducted with you and other members of your staff on February 10, 2014.

The enclosed inspection report discusses two findings, one that has preliminarily been determined to be Red with high safety significance for Unit 1, and one that has preliminary been determined to be Yellow with substantial safety significance for Unit 2, that may require additional regulatory oversight. As described in Section 4OA3.9 of the enclosed report, the findings are associated with the March 31, 2013, Unit 1 stator drop that affected safety-related equipment on both units.

The cause for the stator drop was not following a quality-related procedure, in that, the overhead temporary hosting assembly was not properly designed; the associated calculation was not reviewed; and the assembly was not load tested as required. During the movement of the Unit 1 stator, the overhead temporary hoisting assembly collapsed, causing the 525-ton stator to fall on and extensively damage portions of the Unit 1 turbine deck and subsequently to fall over 30 feet into the train bay. The stator drop resulted in a Unit 1 loss of offsite power for 6 days and a Unit 2 reactor trip and loss of offsite power to one vital bus. The dropped stator ruptured a common fire main header in the train bay, which caused flooding in Unit 1 and water damage to the electrical switchgear for Unit 2. The alternate alternating current diesel generator (station blackout) electrical supply cables to both units were pulled out of the electrical switchgear and the diesel was therefore not available to either unit. In addition, there was one fatality and eight individuals were injured. The Occupational Safety and Health Administration (OSHA) conducted an independent inspection focusing on industrial safety aspects of the event and issued four separate Citations and Notification of Penalties on September 26, 2013, with proposed fines to the three involved contractors and Entergy Operations, Incorporated.

Your staff conducted extensive reviews of this event in the root cause evaluation, documented in Condition Report CR-ANO-C-2013-00888. Corrective actions included: repairing the damaged Unit 1 turbine structure, fire main system, and both Unit 1 and Unit 2 electrical systems; modifying procedures related to handling of heavy loads; training your staff on the revised requirements for handling heavy loads; and providing additional oversight for the subsequent Unit 1 replacement stator lift. The NRC inspectors observed many of the repair activities, including the removal of the dropped stator and the subsequent Unit 1 replacement stator lift. We noted that in your root cause evaluation, your staff did not address Entergy's oversight of the contractors involved with the stator lift. The NRC independently determined that Entergy did not ensure adequate supervisory and management oversight of the contractors and other supplemental personnel involved with the stator lift, and this contributed to the event.

These findings were assessed based on the best available information, using the applicable Significance Determination Process. The final resolution of these findings will be conveyed in separate correspondence. These findings also constitute an apparent violation of NRC requirements which is being considered for escalated enforcement action in accordance with the NRC Enforcement Policy, which appears on the NRC's Web site at: http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

In accordance with NRC Inspection Manual Chapter 0609, "Significance Determination Process," we intend to complete our evaluation and issue our final determination of safety significance within 90 days from the date of this letter. The NRC's significance determination process is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

During the exit meeting, conducted on February 10, 2014, you requested a regulatory conference to discuss these findings. As such, a regulatory conference to discuss the apparent violation has been scheduled for Thursday, May 1, 2014, from 1 - 5 p.m. at the Nuclear Regulatory Commission Region IV office in Arlington, Texas. We encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. This conference will be open to public observation in accordance with Section 2.4, "Participation in the Enforcement Process," of the NRC Enforcement Policy. The NRC will issue a public meeting notice and press release to announce this conference. At the February 10th exit meeting, both you and your staff expressed concerns that the NRC was not providing any credit for B.5.b mitigation equipment in the NRC's preliminary risk analysis. As part of our risk analysis, we acknowledged that some credit may be appropriate. We encourage you to be prepared to discuss, at the regulatory conference, what range of credit should be applied and the supporting basis, to include such things as procedures, training, pre-staging of equipment, etc.

Please contact Gregory Werner at 817-200-1574, and in writing, within 10 days from the issue date of this letter to confirm your intentions to attend a regulatory conference as described above. If we have not heard from you within 10 days, we will continue with our final significance determination and enforcement decision.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for these inspection findings at this time. In addition, please be advised that the

number and characterization of the apparent violation may change based on further NRC review.

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

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

If you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV; and the NRC resident inspector at the Arkansas Nuclear One.

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

Sincerely,

/RA/

Marc L. Dapas
Regional Administrator

Docket Nos: 50-313, 50-368
License Nos: DRP-51, NPF-6

Enclosure: Inspection Report 05000313/2013012 and 05000368/2013012
w/Attachment 1: Supplemental Information
w/Attachment 2: Unit 1 Outage Detailed Risk Evaluation
w/Attachment 3: Unit 2 At-Power Detailed Risk Evaluation

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SUNSI Rev Compl.	☑Yes ☐ No	ADAMS	☑Yes ☐ No	Reviewer Initials	GEW
Publicly Avail.	☑Yes ☐ No	Sensitive	☐Yes ☑ No	Sens. Type Initials	GEW
SRI:DRS/TSB	SRI:DRS/EB1	PE:DRP/E	RI:DRS/EB2	SRA:DRS/EB2	SRRA:NRR/ DRA/APOB
LWilloughby	RLatta	JMelfi	NOkonkwo	DLoveless	JMitman
via email	via email	via email	via email	J.Dixon for	Via email
3/13/14	3/6/14	3/5/14	3/4/14	3/12/14	3/10/14
SES:ACES	C:ORA/ACES	RC:ORA	AC:DRP/E	DD:DRP	D:DRP
RBrowder	VCampbell	KFuller	GWerner	TPruett	KKennedy
/RA/	/RA/	/RA/	/RA/	/RA/	/RA/
3/14/14	3/17/14	3/17/14	3/13/14	3/13/14	3/18/14
OE	NRR	RA			
LCasey	CSanders	MDapas			
via email	via email	/RA/			
3/21/14	3/24/14	3/24/147			

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	05000313; 05000368
License:	DRP-51; NPF-6
Report:	05000313; 05000368/2013012
Licensee:	Entergy Operations, Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	Junction of Hwy. 64 West and Hwy. 333 South Russellville, Arkansas
Dates:	July 15, 2013 through February 10, 2014
Inspectors:	Leonard Willoughby, Senior Reactor Inspector Bob Latta, Senior Reactor Inspector Jim Melfi, Project Engineer Nnaerika Okonkwo, Reactor Inspector
Approved By:	Gregory Werner Acting Chief, Project Branch E Division of Reactor Projects

SUMMARY

IR 05000313; 05000368/2013012; 07/15/2013 – 02/10/2014; Arkansas Nuclear One; Augmented Inspection Team Follow-up Report; Inspection Procedure 71153, “Follow-up of Events and Notices of Enforcement Discretion.”

The inspection activities described in this report were performed by four inspectors from the NRC’s Region IV office. One preliminary finding of high safety significance (Red), one preliminary finding of substantial safety significance (Yellow), and three findings of very low safety significance (Green) are documented in this report. Both of the preliminary findings constitute an apparent violation and two of the Green findings involved violations of NRC requirements. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, “Significance Determination Process.” Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, “Components Within the Cross-Cutting Areas.” Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process.”

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Unit 1 Apparent Violation. The inspectors reviewed a self-revealing apparent violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” which states, in part, that “activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings.” The licensee did not follow the requirements specified in Procedure EN-MA-119, “Material Handling Program,” in that, the licensee did not perform an adequate review of the subcontractor’s lifting rig design calculation and the licensee failed to conduct a load test of the lifting rig prior to use. The licensee initiated Condition Report CR-ANO-C-2013-00888 to capture this issue in the corrective action program. The licensee’s corrective actions included repairing damage to the Unit 1 turbine deck, fire main system, and electrical system. In addition, changes were made to various procedures including Procedure EN-DC-114, “Project Management,” to provide guidance on review of calculations, quality requirements, and standards associated with third party reviews.

  The inspectors determined that the finding was more than minor because it was associated with the procedural control attribute of the initiating event cornerstone, and adversely affected the cornerstone’s objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The stator drop affected offsite power to Unit 1, resulting in a loss of offsite power for approximately 6 days and a loss of the alternate AC diesel generator. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, to evaluate the significance of the finding. Since the plant was shutdown, the inspectors were directed to Inspection Manual Chapter 0609, Appendix G, Attachment 1, “Shutdown Operations Significance Determination

Process Phase 1 Operational Checklists for Both PWRs and BWRs," Checklist 4, dated May 25, 2004. Using Appendix G, Attachment 1, Checklist 4, the inspectors concluded that this finding represented a degradation of the licensee's ability to add reactor coolant system inventory when needed since a loss of offsite power occurred and therefore, this finding required a Phase 3 analysis. A shutdown risk model was developed by modifying the at-power Arkansas Nuclear One Unit 1 Standardized Plant Analysis Risk Model, Revision 8.19. The NRC risk analyst assessed the significance of shutdown events by calculating an instantaneous conditional core damage probability. The results were dominated by two sequences. The largest risk contributor (approximately 97 percent) was based on a failure of the emergency diesel generators without recovery. The second largest risk contributor was the failure to recover decay heat removal. The result of the analysis was an instantaneous conditional core damage probability of 3.8E-4; therefore, this finding was preliminarily determined to have high safety significance (Red).

This finding had a cross-cutting aspect in the area of human performance associated with field presence, because the licensee did not ensure adequate supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, the licensee did not provide a sufficient level of oversight in that, the requirements in Procedure EN-MA-119, for design approval and load testing of the temporary hoisting assembly, were not followed [H.2] (Section 4OA3.9).

- <u>Unit 2 Apparent Violation.</u> The inspectors reviewed a self-revealing apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," which states, in part, that "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings." The licensee did not follow the requirements specified in Procedure EN-MA-119, "Material Handling Program," in that, the licensee did not perform an adequate review of the subcontractor's lifting rig design calculation and the licensee failed to conduct a load test of the lifting rig prior to use. The licensee initiated Condition Report CR-ANO-C-2013-00888 to capture this issue in the corrective action program. The licensee's corrective actions included repairing damage to the Unit 1 turbine deck, fire main system, and electrical system. In addition, changes were made to various procedures including Procedure EN-DC-114, "Project Management," to provide guidance on review of calculations, quality requirements, and standards associated with third party reviews.

  The inspectors determined that this finding was more than minor because it was associated with the procedural control attribute of the initiating event cornerstone, and adversely affected the cornerstone's objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The stator drop caused a reactor trip on Unit 2 and damage to the fire main system which resulted in water intrusion into the electrical equipment causing a loss of startup transformer 3. This resulted in the loss of power to various loads, including reactor coolant pumps, instrument air compressors, and the safety-related Train B vital electrical bus. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial

Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to evaluate the significance of the finding. Since this was an initiating event, the inspectors used Exhibit 1 of Appendix A and determined that Section C, "Support System Initiators," was impacted because the finding involved the loss of an electrical bus and a loss of instrument air. The inspectors determined that Section E, "External Event Initiators," of Exhibit 1 should also be applied because the finding impacted the frequency of internal flooding. Since Sections C and E were impacted, a detailed risk evaluation was required. The NRC risk analyst used the Arkansas Nuclear One, Unit 2 Standardized Plant Analysis Risk Model, Revision 8.21, and hand calculation methods to quantify the risk. The model was modified to include additional breakers and switching options, and to provide credit for recovery of emergency diesel generators during transient sequences. Additionally, the analyst performed additional runs of the risk model to account for consequential loss of offsite power risks that were not modeled directly under the special initiator. The largest risk contributor (approximately 96 percent) was a loss of all feedwater to the steam generators, with a failure of once-through cooling. The result of the analysis was a conditional core damage probability of 2.8E-5; therefore, this finding was preliminarily determined to have substantial safety significance (Yellow).

This finding had a cross-cutting aspect in the area of human performance associated with field presence, because the licensee did not ensure adequate supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, the licensee did not provide a sufficient level of oversight in that, the requirements in Procedure EN-MA-119, for design approval and load testing of the temporary hoisting assembly, were not followed [H.2] (Section 4OA3.9).

Cornerstone: Mitigating Systems

- Green. The inspectors reviewed a self-revealing, non-cited violation of Unit 1 Technical Specification 5.4.1.a and Unit 2 Technical Specification 6.4.1.a, involving the licensee's failure to develop and implement procedural controls for response to internal flooding. Specifically, the licensee did not incorporate any instructions for the operation of the permanently installed temporary fire pump into procedures, which resulted in flooding due to the ruptured fire main header and not securing the temporary fire pump for approximately 50 minutes. The licensee's corrective actions included changing Checklist 1104.032, "Fire Protection Systems," Revision 76, to include guidance for securing the temporary fire pump in the event of a leak or rupture in the fire main header and provided personnel training on this change. This issue was entered into the corrective action program as Condition Reports CR-ANO-C-2013-01072 and CR ANO-C-2013-01962.

  The inspectors determined that the licensee's failure to develop and implement adequate procedural controls for the permanently installed temporary fire pump was a performance deficiency. The performance deficiency was more than minor because it was associated with the procedural quality attribute of the mitigating systems cornerstone and affected the cornerstone's objective to ensure the availability, reliability, and capability of systems that respond to

initiating events to prevent undesirable consequences (i.e. core damage). Specifically, if the necessary flood prevention/mitigation actions cannot be completed in the time required, much of the station's accident mitigation equipment could be adversely impacted.

Unit 1 Analysis:

Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, Table 3, Section A, directs the user to Appendix G. The inspectors used Inspection Manual Chapter 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs," dated May 25, 2004, Checklist 4, to evaluate the significance of the finding. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not: (1) increase the likelihood of a loss of reactor coolant system inventory, (2) degrade the licensee's ability to terminate a leak path or add reactor coolant system inventory when needed, or (3) degrade the licensee's ability to recover decay heat removal once it is lost.

Unit 2 Analysis:

Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, Table 3, Section E, Step 2, directs the user to Appendix F, "Fire, Protection Significance Determination Process," dated September 20, 2013. The inspectors used Appendix F, to evaluate the significance of the finding. The finding involved a fixed fire protection system and the fire water supply (temporary fire pump). The finding was screened against the qualitative screening question in Appendix F, Task 1.3.1 and the inspectors determined it was of very low safety significance (Green), because the reactor was able to reach and maintain safe shutdown.

The finding had a cross-cutting aspect in area of the human performance associated with documentation, because the licensee failed to create and maintain complete, accurate, and up-to-date documentation for the use of the temporary fire pump [H.7] (Section 4OA3.1).

- Green. The inspectors reviewed a self-revealing finding for the licensee's failure to provide appropriate work instructions for the replacement of the main feedwater regulating valve 2CV-0748 linear variable differential transformer 2ZT-0748. Specifically, the licensee failed to translate vendor recommendations for use of a thread sealant, and torqueing of the adjustment nuts on the linear variable differential transformer 2ZT-0748 into procedural steps to be accomplished and verified. The failure to follow these recommendations resulted in the nuts falling off because of vibration. The licensee initiated Condition Report CR-ANO-2-2013-00423 and Work Order WT-WTANO-2013-00039 to update the work instructions and perform maintenance to repair the valve position indication by adding thread sealant and torqueing the adjustment nuts to prevent them from loosening.

  The inspectors determined that the failure to provide instructions to properly perform maintenance on linear variable differential transformer 2ZT-0748 was a

performance deficiency. The performance deficiency was more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone. It adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and is therefore a finding. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to evaluate the significance of the finding. The inspectors determined the finding was of very low safety significance (Green) because the finding did not: (1) result in an actual loss of operability or functionality, (2) represent a loss of system and/or function, (3) represent an actual loss of function of a single train for greater than its technical specification allowed outage time, (4) represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours, and (5) involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather event. The finding had a cross-cutting aspect in the area of the problem identification and resolution associated with operating experience, because although the licensee had collected and evaluated the operating experience, it was not implemented as procedural steps in linear variable differential transformer replacement work instructions [P.5] (Section 4OA3.4).

- Green. The NRC identified a non-cited violation of 10 CFR 50.65(b)(2)(i) for the licensee's failure to monitor non-safety-related structures, systems, or components that are relied upon to mitigate accidents or transients. Specifically, the Unit 1 decay heat removal pump room level switches, which were credited for mitigating the effects of internal flooding, were not being monitored as part of the maintenance rule. The licensee's corrective actions included developing a preventative maintenance task to test the operation of the level switches. This issue was entered into the corrective action program as Condition Report CR-ANO-1-2013-03168.

  The inspectors determined that the failure to effectively monitor the performance of both Unit 1 decay heat removal room level switches in accordance with 10 CFR 50.65(a)(1) was a performance deficiency. The performance deficiency was determined to be more than minor because it affected the equipment performance attribute of the mitigating systems cornerstone and directly affected the cornerstone objective of ensuring the availability and reliability of systems that respond to initiating events to prevent undesirable consequences, in that it called into question the reliability of flood mitigation equipment. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to evaluate the significance of the finding. The inspectors determined the finding was of very low safety significance (Green) because the finding did not: (1) result in an actual loss of operability or functionality, (2) represent a loss of system and/or function' (3) represent an actual loss of function of a single train for greater than its technical specification allowed outage time, (4) represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater

than 24 hours, and (5) involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather event. This finding did not have a cross-cutting aspect since the switches were installed and evaluated in 2003, and therefore it is not indicative of current performance (Section 4OA3.5.2).

REPORT DETAILS

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

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

.1 (Closed) Unresolved Item 05000313/2013011-001, "Control of Temporary Modification Associated with Temporary Fire Pump"

The Augmented Inspection Team identified an unresolved item associated with operator control of the water supply to the station fire suppression system and the control of a temporary fire pump modification. Specifically, following the stator drop, a significant fire water leak occurred in the turbine building train bay as a result of a ruptured eight-inch fire water header. The Augmented Inspection Team determined that 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.

Observations and Findings

Introduction. The Augmented Inspection Team, Follow-up Team (inspectors) reviewed a self-revealing, Green non-cited violation of Unit 1 Technical Specification 5.4.1.a and Unit 2 Technical Specification 6.4.1.a, involving the licensee's failure to develop and implement procedural controls for response to internal flooding.

Description. In 1999, the licensee installed a temporary fire pump that could be used during outages or other times when the permanently installed fire pumps were out of service. The power supply for this electric fire pump was from the London 13.8 kV line, which is an additional offsite power source not included in the plant Technical Specifications. This temporary fire pump allowed the licensee to perform maintenance on installed fire pumps and still maintain fire water suppression capability for the site. 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.

The collapse of the temporary hoisting assembly and the drop of the generator stator ruptured an eight-inch fire main in the train bay. 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 gpm 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. However, several subsequent log entries reflected significant water flow from the fire suppression system in the turbine building and into the Unit 1 auxiliary building. A log entry, made 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 firewater into the train bay. A log entry five minutes later stated that the temporary fire pump was secured.

The Augmented Inspection 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 Augmented Inspection 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. However, the Augmented Inspection Team also identified indications of system pressure consistent with an operating pump approximately 40 minutes after the event.

Based on uncertainties associated with the time line for operator response, the inspectors examined the licensee's revised sequence of events for securing the supply of water to the fire main rupture in the turbine building train bay, conducted system walk downs, and reviewed the available video records of the stator drop event. As a result of these reviews, the inspectors determined that the initial timeline for securing the temporary firewater pump, documented in Corrective Action 1, of Condition Report CR-ANO-C-2013-01072, was at least 10 minutes longer than the previously estimated time of 8:19 a.m. Specifically, review of video evidence established that the temporary firewater pump was secured between 8:29 a.m. and 8:38 a.m. This time frame was predicated on observed flow in the video recording at 8:24 a.m. with pressure beginning to drop at approximately 8:29 a.m. and no firewater flow from the ruptured pipe evident at 8:38 a.m.

The inspectors also reviewed the temporary fire pump installation procedure, the associated 10 CFR 50.59 evaluation, the associated operations training material, and the corrective actions identified in Condition Report CR-ANO-C-2013-01072. From these reviews, the inspectors determined that subsequent to the event, extensive corrective actions had been developed to address the prolonged operator response time for securing the temporary fire pump. However, the inspectors determined that prior to the event, there were no specific procedural controls, guidance, or standing orders which directed operations personnel to secure firewater pumps in the event of flooding caused by a fire system leak. The licensee's corrective actions included changing Checklist 1104.032, "Fire Protection Systems," Revision 76, to include guidance for securing the temporary fire pump in the event of a rupture in the fire main and provided training on this change. This issue was entered into the corrective action program as Condition Reports CR-ANO-C-2013-01072 and CR-ANO-C-2013-01962.

<u>Analysis.</u> The inspectors determined that the licensee's failure to develop and implement adequate procedural controls for the permanently installed temporary fire pump was a performance deficiency. The performance deficiency was more than minor because it impacted the procedural quality attribute of the mitigating systems cornerstone and affected the cornerstone's objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, if the necessary remedial actions cannot be completed in the time required, some of the station's accident mitigation equipment could be adversely impacted.

Unit 1 Analysis:

Inspection Manual Chapter 0609, Attachment 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, Table 3, Section A, directs the user to Appendix G. The inspectors used Inspection Manual Chapter 0609, Appendix G, Attachment 1, “Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs,” dated May 25, 2004, Checklist 4, to evaluate the significance of the finding. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not: (1) increase the likelihood of a loss of reactor coolant system inventory, (2) degrade the licensee’s ability to terminate a leak path or add reactor coolant system inventory when needed, and (3) degrade the licensee’s ability to recover decay heat removal once it is lost.

Unit 2 Analysis:

Inspection Manual Chapter 0609, Attachment 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, Table 3, Section E, Step 2, directs the user to Appendix F, “Fire, Protection Significance Determination Process” dated September 20, 2013. The inspectors used Appendix F, to evaluate the significance of the finding. The finding involved a fixed fire protection system and the fire water supply (temporary fire pump). The finding was screened against the qualitative screening question in Appendix F, Task 1.3.1 and the inspectors determined it was of very low safety significance (Green), because the reactor was able to reach and maintain safe shutdown.

The finding had a cross-cutting aspect in area of the human performance associated with documentation, because the licensee failed to create and maintain complete, accurate, and up-to-date documentation for the use of the temporary fire pump [H.7] (Section 4OA3.1).

Enforcement. Unit 1 Technical Specification 5.4.1.a and Unit 2 Technical Specification 6.4.1.a, state that, “Written procedures shall be established, implemented, and maintained covering the following activities: The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.” Regulatory Guide 1.33, “Quality Assurance Program Requirements (Operation),” February 1978, Appendix A, Section 6.r, requires, in part, implementation of approved procedures for combating emergencies and other significant events, including other expected transients that may be applicable. Contrary to the above, since 1999, the licensee failed to establish a procedure to address the requirements of Regulatory Guide 1.33, Appendix A, Section 6.r. Specifically, Procedure 1104.032, “Fire Protection Systems,” Revision 75, did not contain specific controls or guidance to secure the temporary fire pump in the event of flooding caused by a fire system leak. Since this finding is of very low safety significance and has been entered into the corrective action program as Condition Reports CR-ANO-C-2013-01072 and CR-ANO-C-2013-01962, this violation is being treated as a non-cited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000313/20130012-01; 05000368/20130012-01; “Failure to Adequately Develop and Implement Adequate Procedural Controls to Remediate the Anticipated Effects of Internal Flooding for Either Unit.”

.2 (Closed) Unresolved Item 05000313/2013011-002; 05000368/2013011-002, "Damage to Unit 1 and Unit 2 Structures, Systems and Components"

The Augmented Inspection Team concluded that the licensee had appropriate plans in place to identify affected equipment, control access to the affected areas, and commence debris removal and repair activities after the stator drop occurred. However, since a full assessment of the damage to Unit 1 and Unit 2 structures, systems, components following the dropped stator was not possible until debris had been removed, an unresolved item was opened to assess the damage.

Observations and Findings

The inspectors reviewed Condition Reports CR-ANO-1-2013-00868 and CR-ANO-2-2013-00620, and performed visual inspections of walls, floors, structural supports, and ceilings. The inspectors visually inspected support beams, conduit, cable raceways, ventilation ducting, hydrogen piping, carbon dioxide piping, instrument air piping, and equipment in the affected areas.

The inspectors discussed with the licensee the effect of the dropped stator on electrical busses, raceways and cabling, and the acceptance testing the licensee performed on the affected cables. The inspectors also reviewed and discussed the post-installation testing the licensee performed on the repaired Unit 1 4160 Vac switchgear.

The inspectors toured affected areas, looking at the turbine building structures and components. Acceptance testing of the repaired switchgear was ongoing, but was mostly completed by the time of the inspection. The inspectors concluded that the turbine building structures were repaired to the same condition as they were prior to the stator drop, with exceptions, that included:

> The non-load bearing masonry block wall between the machine shop and the train bay was not replaced. The licensee relocated the machine shop equipment to a different facility outside the protected area, and intends to use the area between the train bay and former machine shop as a storage area during future refueling outages.

The inspectors concluded that the repairs to the turbine building structures and components were effective.

No findings were identified.

.3 (Closed) Unresolved Item 05000313/2013011-003, "Procedural Controls Associated with Unit 1 Steam Generator Nozzle Dams"

The Augmented Inspection Team identified an unresolved item associated with the procedural controls for the backup air supply systems to the Unit 1 nozzle dams. The inspectors 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.

a. <u>Observations and Findings</u>

On March 28, 2013, the Unit 1 steam generator nozzle dams were installed. The nozzle dams consisted of one rigid plug and two inflatable dams, installed in the reactor coolant system piping that provided access for work inside the steam generators while maintaining water inventory in the reactor coolant system. The inflatable nozzle dams are pressurized to a normal operating pressure of approximately 75 psig. On a loss of seal pressure, the design of the nozzle dams limits the maximum leakage through the seals to approximately 2 gpm. The normal system lineup included a regulated 90 psig primary supply with an independent 80 psig backup pressure source. At the time of the stator drop event, the primary supply for the nozzle dams consisted of a portable electric air compressor with the backup supply provided by a second portable electric air compressor powered by a different train of non-safety-related electrical power. In the event of loss of both air supplies, the licensee's contingency plan provided for the use of the instrument air system.

The stator drop event resulted in the loss of offsite electrical power to Unit 1 and most of the power to the containment building, including loss of power to both air compressors for the nozzle dams. The nozzle dams began to lose pressure, due to the check valves on the air supply lines leaking. At approximately 9:30 a.m., personnel entered containment and observed nozzle dam pressure was approximately 50 psig and falling. The licensee's steam generator engineer requested nitrogen bottles be brought into containment. While waiting for the nitrogen bottles, nozzle dam pressures approached 25 psig, at which point the nozzle dam seals were subject to reactor coolant system leakage. The steam generator engineer connected the local instrument airline to the nozzle dams; however, 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. Compressed nitrogen bottles were subsequently taken into containment and aligned to the nozzle dam consoles and seal pressure was restored to approximately 70 psig. However, as a result of degraded seal pressure, a small amount of reactor coolant system inventory leaked past the nozzle dam seals.

Recovery efforts also included connecting 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 London 13.8kV line, which was not affected by the stator drop event. The refueling air compressor was placed into service as the primary source of air for nozzle dam seal pressurization with the nitrogen bottles as the backup source. The licensee established local nozzle dam checks on a two-hour frequency. The inspectors determined the licensee's response to this event was appropriate.

The inspectors reviewed design documents and industry information associated with the nozzle dam design. Unit 1 Safety Analysis Report Section 4.2.2.2, "Steam Generator," indicated that the nozzle dams prevent water from entering the steam generators. Section 4.2.2.2 also stated that the nozzle dams serve no safety function. Engineering Evaluation ER981203 E101, "Engineering Evaluation of the ANO-1 Steam Generator Nozzle Dams," dated January 1999, documented that the nozzles dam structure consisted of two redundant inflatable seals and one passive emergency backup seal. The design of the seals was for the inflatable seals to provide the primary and normal backup seal and in the unlikely event of both inflatable seals failing, the passive seal

would limit leakage to less than 2 gpm, as stated above. The design of the seal was consistent with industry guidance to limit leakage on the event of a catastrophic inflatable seal failure. The inspectors reviewed the original procurement Specification ANO-M-434, "Specification for Arkansas Nuclear One Russellville, Arkansas OTSG [Once-Through Steam Generator] Nozzle Dams," dated April 20, 1990. The nozzle dams, including the seals, were procured as non-quality related.

As documented in Condition Report CR-ANO-1-2013-00917, the corrective actions included leak testing of the nozzle dam check valves and having nitrogen bottles as a backup source of air in case of loss of electrical power to the air compressors. One of the contributors to the loss of seal pressure was that in 2010, Procedure OP-5120.504, "OTSG Nozzle Dam Training, Testing and Installation/Removal," Revision 6, was revised to allow various options for maintaining seal pressure, and nitrogen bottles were no longer used based on the operational convenience of not bringing the bottles into containment. The inspectors determined that the change in 2010, to remove the nitrogen bottles, was non-conservative.

No findings were identified.

.4 (Closed) Unresolved Item 05000368/2013011-004, "Main Feedwater Regulating Valve Maintenance Practices"

The Augmented Inspection Team identified an unresolved item associated with licensee maintenance practices involving the main feedwater regulating valves. The inspectors concluded that additional inspection was required to assess the effectiveness of the licensee maintenance practices for the main feedwater regulating valves.

Following the Unit 2 reactor trip on March 31, 2013, operators identified that main feedwater regulating valve A failed to indicate closed. This indication resulted in the operators tripping main feedwater pump A and manually initiating the emergency feedwater actuation system. Operators subsequently placed the auxiliary feedwater system in service, which required operators to manually inhibit the emergency feedwater system, rendering both trains of emergency feedwater inoperable and requiring entry into Technical Specification 3.0.3 for a short period of time. The licensee later determined that the regulating valve actually had closed, and the valve indication was in error.

Observations and Findings

Introduction. The inspectors reviewed a Green self-revealing finding associated with a failure to provide sufficient work instructions for the replacement of the main feedwater regulating valve 2CV-0748 linear variable differential transformer 2ZT-0748. Specifically, the licensee failed to translate vendor recommendations to use a thread sealant and torqueing the adjustment nuts on the linear variable differential transformer 2ZT-0748, into procedural steps to be accomplished and verified. The failure to use thread sealant and torque the adjustment nuts resulted in the nuts loosening and falling off because of vibration. The licensee initiated corrective actions, Condition Report CR-ANO-2-2013-00423 and Work Order WT-WTANO-2013-00039 to perform maintenance to add thread sealant, and torque the nuts to prevent the nuts from loosening.

Description. Following the Unit 2 reactor trip on March 31, 2013, operators identified that main feedwater regulating valve 2CV-0748 went closed; however, the digital indications provided from the valve linear variable differential transformer and limit switches falsely showed the valve to be 7.7 percent open. These indications resulted in the operators tripping main feedwater pump A and manually initiating the emergency feedwater actuation system in accordance with Procedure 2002-001, "ANO standard Post Trip Action," Revision 13. 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 complicated operator response to the trip.

The licensee later determined that the regulating valve actually had closed, and the valve indication was in error. Based on its investigation, the licensee determined that the lower nut, which holds the "LVDT 2ZT-0748, MFW 2P-1A DISCH MAIN REG LVDT" on a support plate on which the limit switches were also mounted, was missing. The missing nut caused the linear variable differential transformer and the valve limit switch, which provide digital indication for feedwater loop A main regulating valve position, to show an incorrect valve position indication.

The linear variable differential transformer was replaced during refueling outage 2R22, which occurred in the fall of 2012. Maintenance work order MWO-5024186-01 had a note that required thread sealant for the linear voltage differential transformer rod. The work order did not provide steps for the application of thread sealant for the upper and lower nuts that hold the linear variable differential transformer rod. The use of a note was contrary to Procedure EN-AD-101-01, "Nuclear Management Manual Procedure Writer Guide," Section I, Item 7, which specified that, notes are to be used for clarifying information and are not to contain action instructions.

As corrective actions, the licensee torqued and added thread sealant to the nuts that held the linear variable differential transformer rod; modified the work order to add steps to install thread sealant; and, torqued the upper and lower nuts of the linear variable differential transformer rod. The linear variable differential transformer was also calibrated and tested.

Analysis. The inspectors determined that the failure to provide instructions to properly perform maintenance on linear variable differential transformer 2ZT-0748 was a performance deficiency. The performance deficiency was more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone. It adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and is therefore a finding. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to evaluate the significance of the finding. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not: (1) result in an actual loss of operability or functionality, (2) represent a loss of system and/or function, (3) represent an actual loss of function of a single train for greater than its technical specification allowed outage time, (4) represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours, and (5) involve the loss or degradation of equipment or function specifically designed to mitigate a seismic,

flooding, or severe weather event. The finding had a cross-cutting aspect in the area of problem identification and resolution associated with operating experience, because although the licensee had collected and evaluated the operating experience, it was not implemented as procedural steps in linear variable differential transformer replacement work instructions [P.5].

Enforcement. This finding does not involve a violation, because there is no regulatory requirement associated with this finding. As such, and because the associated performance deficiency is of very low safety significance (Green), it is identified as a finding: FIN 05000368/2013012-002, "Main Feedwater Regulating Valve Maintenance Practices."

.5 (Discussed) Unresolved Item 05000313/2013011-005, "Flood Barrier Effectiveness"

The Augmented Inspection Team noted that following the stator drop, a significant fire water leak occurred in the train bay from a ruptured eight-inch fire header. Due to the approximately 50 minute time before the pipe rupture was isolated, fire water sprayed into the auxiliary building and accumulated in the general area access at the 317 foot elevation. Water also accumulated in the flood protected decay heat vault B, which is also on the 317 foot elevation. The Augmented Inspection Team concluded that additional inspection was required to determine the causes and impact of the failed flood hatches and the partially open decay heat vault B, drain isolation valve.

a. Inspection Scope

Background of Unit 1 and Unit 2 Flood Protection Features

The Arkansas Nuclear One facility was built at a plant grade elevation of 354 feet. The design basis flood water level for both Unit 1 and Unit 2 has a projected flood elevation of 361 feet at the site. Safety-related structures, systems, and components necessary for reaching and maintaining safe shutdown are protected against the design basis flood level. The flood protection features for both units are similar, but Unit 2 has a more robust design.

Both units have safety-related structures, systems, and components necessary to maintain safe shutdown for above the design basis flood water level, including the emergency diesel generators, 4160 Vac vital and non-vital switchgear, service water pump motors, and offsite power feeds. Some of this equipment is located in the auxiliary building below the projected flood level and requires protection. Both units' auxiliary building designs incorporate features to keep water out, such as watertight doors, equipment hatches, and concrete plugs with a neoprene seal to prevent water from entering. The incorporated barriers include reinforced concrete walls designed to resist the static and dynamic forces of the projected flood, with special water-stops at construction joints to prevent in-leakage. Pipe penetrations through the walls have special rubber boots or other protective features. In addition, both units have required safety-related structures, systems, and components on the 317 foot elevation partitioned into separate rooms to provide protection in the event of flooding. The partition walls are designed to withstand hydrostatic loading over their full height.

Watertight Rooms in Unit 1 and Unit 2

Unit 1 has two watertight rooms on the 317 foot elevation. Each room contains a train of safety-related equipment, consisting of a decay heat removal pump, a reactor building spray pump, a decay heat removal heat exchanger, and a room cooler. Other Unit 1 safety-related pumps, including the high pressure injection pumps and emergency feedwater pumps, are on the 335 foot elevation and are not in watertight rooms.

Similarly, Unit 2 has watertight rooms for protection of safety-related equipment. Unit 2 has the emergency feedwater pumps protected in watertight rooms located on the 335 foot elevation. Unit 2 has separate trains of low pressure safety injection pumps, high pressure safety injection pumps, and containment spray pumps in separate vaults on the 317 foot elevation. Unit 2 also has a swing high pressure safety injection pump and associated room cooler in a separate vault on the 317 foot elevation.

Any water leakage into the auxiliary building would flow into various floor drains and openings, down to the 317 foot level of each auxiliary building. This leakage would either go into each unit's respective dirty waste storage tank or into the units' auxiliary building sump. Sump pumps are provided to remove any small leakage that could seep through exterior concrete walls and discharge into the dirty waste storage tank. The water can then be transferred out of the dirty waste storage tank to be processed and safely disposed of via each unit's radioactive waste cleanup system. The auxiliary building sump pumps and dirty waste system are non-safety-related. One sump pump will automatically start on Unit 1 at a specified level, and a second pump that could be started manually is available. Unit 2 sump pumps will both start automatically, depending on Unit 2 sump level.

Augment Inspection Follow-up Team Review

The inspectors reviewed the licensee's Condition Report ANO-C-2013-01304 written to address the condition of water entering the Unit 1 auxiliary building, walked down various design features of the auxiliary building, interviewed staff, reviewed records, and associated drawings. Due to the equipment in the turbine building impacted by the stator drop, non-safety-related power was lost and there was no power to the auxiliary building sump pumps and dirty waste storage tank system. The licensee identified about an inch of water in decay heat removal room B and on the general access area of the 317 foot level of the auxiliary building. When water from the broken fire main reached the removable floor plugs, the water leaked past the plugs into the lower auxiliary building elevations, because the plug seals were degraded. The water subsequently reached the 317 foot level of the auxiliary building and filled the auxiliary building sump. Each decay heat removal room has an isolation valve that allows water in the decay heat removal room to be drained to the auxiliary building sump. The isolation valve for the drain from decay heat removal room B was not fully shut and water from the auxiliary building sump flowed back into the room.

b. Observations and Findings

.1 Flood Mitigation Barriers

The inspectors have not completed their evaluation of the licensee's extent of condition for the degraded flood barriers. As such, this unresolved item will remain open and will include the consideration of the following items:

(a) Floor Plugs are designed to allow for access and the movement of components into and out of the lower levels of the auxiliary building. Flood protection for these plugs was provided by a neoprene seal. The licensee had no specified frequency for seal replacement. The seal was either too old and it did not seal, or the design was inadequate in that the seal rolled out of place when the plug was set into the floor.

(b) The decay heat removal room drain valves are manually closed to prevent water from entering the vault. During the event, one drain valve indicated closed, but the valve was partially open, allowing water to enter the room. On several occasions after the event, operators attempted to shut the valve, but it did not fully shut. The lack of maintenance on the associated reach rods, and/or position indication not being correct, or a combination of these two conditions, resulted in plant operators not being able to consistently close the train B decay heat removal vault drain valve.

(c) From its extent of condition review, the licensee identified other paths for water to get into the auxiliary building. These included: drains in the turbine building, a sump from the solid radioactive waste storage building (located in the switchyard) to the Unit 1 auxiliary building sump, unprotected penetrations in the auxiliary building annex, unprotected electrical conduits entering into the auxiliary building, unsealed holes in the auxiliary building from the turbine building, and the tendon gallery access hatches. On March 5, 2014, the licensee submitted a non-emergency 10 CFR 50.72 notification, Event Number 49873, to the NRC for the discovery of pathways that could bypass flood barriers. For immediate corrective actions, the licensee installed barriers in the pathways or implemented compensatory measures.

(d) The NRC needs to determine why these items identified in the extent of condition walk down for the flooding event, caused by the stator drop, were not identified as part of the flooding walk downs described in Arkansas Nuclear One letters, dated November 27, 2012 (ML 12334A008 and ML ML12334A006), in response to the NRC's Request for Information letter, "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3 of the Near-Term Task Force Review of Insights form the Fukushima Dai-ichi Accident," dated March 12, 2012 (ML12053A340).

(e) The safety classification of the vault drain valves as non-safety-related does not appear commensurate with its importance in mitigating a flooding event.

.2 Decay Heat Removal Rooms Flood Level Switches not Scoped into the Maintenance Rule

Introduction. The inspectors identified a Green non-cited violation of 10 CFR-50.65(b)(2)(i) associated with the licensee's failure to monitor non-safety-related structures, systems, and components that are relied upon to mitigate accidents or transients.

Description. During inspection of the water intrusion into Unit 1, the inspectors noted that both Unit 1 decay heat removal rooms contain high level alarm switches that are credited, in part, with mitigating the effects of internal flooding caused by a moderate energy line break. Specifically, if there is internal flooding in one of the Unit 1 decay heat removal rooms as indicated by the room level switch, operators are dispatched to

ensure that the other Unit 1 train decay heat removal room is isolated. The inspectors noted that the failure of these switches could result in operators failing to take actions to mitigate internal flooding.

The level switches associated with Unit 1 decay heat removal rooms provide a control room alarm. The annunciator response Procedure 1203.012H, “Annunciation K09 Corrective Action,” Revision 43, directs the operators to verify that the opposite train room floor drain valve is closed. This action helps ensure that two trains of safety-related equipment are not affected by the flooding.

The licensee installed new level switches in 2003, but determined that no preventive maintenance activity was necessary for these switches. Based on their understanding that these non-safety-related switches are credited with mitigating an accident, and the knowledge that the maintenance rule scoping documents did not identify these level alarm switches, the inspectors questioned how they were being controlled and what type of preventative maintenance was being performed. The licensee’s corrective actions included developing a preventive maintenance task to test the operation of the level switches and the switches operated properly. The licensee entered this issue into the corrective action program as Condition Report CR-ANO-2013-03168.

The inspectors, as part of their independent extent of condition review, looked at how the licensee treats the room level switches in Unit 2 and noted that the licensee had established preventive maintenance tasks to test the operation of the level switches.

Analysis. The failure to effectively monitor the performance of both Unit 1 decay heat removal room level switches in accordance with 10 CFR 50.65(a)(1) was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it affected the equipment performance attribute of the mitigating systems cornerstone, and directly affected the cornerstone objective of ensuring the availability and reliability of systems that respond to initiating events to prevent undesirable consequences, in that it called into question the reliability of flood mitigation equipment. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, and Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” dated June 19, 2012, to evaluate the significance of the finding. The inspectors determined the finding was of very low safety significance (Green) because it did not: (1) result in an actual loss of operability or functionality, (2) represent a loss of system and/or function, (3) represent an actual loss of function of a single train for greater than its technical specification allowed outage time, (4) represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant for greater than 24 hours, and (5) involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding, or severe weather event. This finding did not have a cross-cutting aspect since the switches were installed and evaluated in 2003, and therefore it is not indicative of current performance

Enforcement. Title 10 CFR 50.65(b)(2)(i) requires, in part, that the scope of the monitoring program specified in paragraph (a)(1) shall include non-safety-related structures, systems, and components that are relied upon to mitigate accidents or transients. Contrary to the above, from initial maintenance rule scoping in 1996 to the present, the Unit 1 decay heat removal room level alarm switches (non-safety-related) were not included in the scope of the monitoring program specified in

10 CFR 50.65(a)(1). The inclusion of the Unit 1 decay heat removal room level alarm switches in the scope of the monitoring program is necessary because these components are relied upon to mitigate accidents or transients. Since this finding is of very low safety significance and has been entered into the corrective action program as Condition Report CR-ANO-1-2013-03168, this violation is being treated as a non-cited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000313/2013013-003, "Failure to Scope Required Components in the Station's Maintenance Rule Monitoring Program."

.6 (Closed) URI 05000313; 368/2013011-006, "Compensatory Measures for Firewater System Rupture"

The Augmented Inspection Team identified an unresolved item associated with the licensee's compensatory measures for fire suppression prior to the restoration of the damaged firewater system. The inspectors concluded that additional inspection was needed to fully assess the effectiveness of the compensatory measures and the timeliness of the firewater system restoration.

Observations and Findings

The inspectors conducted interviews with on-shift licensee personnel assigned to establish compensatory measures for the damaged fire main. The inspectors toured the areas impacted by the damaged fire main and reviewed the Unit 1 and Unit 2 Technical Requirements Manual.

The Unit 1 stator drop caused damage to an eight-inch fire main pipe that feeds various fire stations. To control flooding, the fire suppression system was secured until the damaged piping could be isolated.

The licensee did establish compensatory measures while isolating and repairing the damaged fire main system. In addition, before the Unit 2 startup, the licensee established compensatory measures to meet conditions specified in the Unit 2 Technical Requirements Manual. The inspectors reviewed the compensatory measures implemented by the licensee and determined that they were appropriate.

No findings were identified.

.7 (Closed) URI 05000368/2013011-007, "Timeliness of Emergency Action Level Determination"

The Augmented Inspection 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. The inspectors 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.

Observations and Findings

The inspectors conducted interviews with on-shift licensee personnel and physically observed the damaged electrical area in order to make an independent assessment of the information needed to determine if criteria was met for an emergency declaration.

The inspectors concluded that a correct and timely emergency declaration was made by the licensee.

The Unit 1 stator drop caused damage to an eight-inch fire main and a wall adjacent to the Unit 2 4160 Vac non-vital switchgear. The spray from the damaged fire main piping impacted the Unit 2 switchgear breaker enclosures and accumulated on the floor. The water spray and/or the water accumulation caused breaker 2A-113 to short and explode, vaporizing the components within the breaker cubicle.

The initial report to the control room at 9:25 a.m. was that one of the breaker doors on switchgear bus 2A1 has been knocked open, but licensee personnel were unable to determine at that time which breaker had been impacted. Light smoke with no visible fire, from the back of one breaker in switchgear bus 2A2, was reported. There was standing water around the switchgear. The March 31, 2013, dayshift Unit 2 Shift Manager walked the inspectors around the Unit 2 non-vital switchgear explaining the conditions observed in the area after the Unit 1 stator drop event. At the time of the event, the licensee determined that it was unsafe for personnel to approach the breaker. Approximately one hour later, conditions were such that licensee personnel could observe the breaker cubicle to make a preliminary assessment. The licensee noted metal splatter on the inside of the door that would indicate a high-energy event, i.e. explosion, from possible water intrusion into the breaker cubicle. According to the Unit 2 station logs, when these observations were reported to the control room operators, the shift manager declared an emergency declaration of a Notice of Unusual Event at 10:34 a.m. Initial notifications of the Notice of Unusual Event were completed at 10:48 a.m. per the logs. The inspectors determined that upon identification of the explosion of breaker 2A-113, the shift manager made the emergency declaration notification to offsite parties within 15 minutes of the initial emergency declaration.

No findings were identified.

.8 <u>(Closed) Unresolved Item 05000313/2013011-008, "Effectiveness of Shutdown Risk Management Program"</u>

The Augmented Inspection Team determined that additional inspection was necessary to assess the effectiveness of the licensee's risk mitigating measures associated with the stator move.

<u>Observations and Findings</u>

The inspectors reviewed Condition Reports CR-ANO-1-2013-00132 and CR-ANO-1-2013-01028, as well as Procedures EN-FAP-OU-100, "Refueling Outage Preparation and Milestones," Revision 1 and EN-OU-108, "Shutdown Safety Management Program," Revision 5. These procedures 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. Procedure EN-OU-108, Step 5.4, described two types of contingency plans that needed to be developed. The stator move fell under the definition of an outage risk contingency plan. Procedure EN-FAP-OU-100 also described the level of contingency planning necessary based on the probability of an issue/problem occurring and the potential impact the issue/problem could have. Plant history, industry experience, and worker knowledge were used to evaluate probability and impact. Probabilities of an

issue/problem were further delineated into “High,” “Medium,” or “Low,” and the impacts of an issue were also delineated as “High,” “Medium,” or “Low.”

The movement of the stator was a high impact, but low probability event. The inspectors noted that Procedure EN-FAP-OU-100, Section 7.7, did not require a contingency plan because of the low probability of the event. The inspectors reviewed Regulatory Guide 1.182, “Assessing and Managing Risk before Maintenance Activities at Nuclear Power Plants,” dated May 2000, which endorses NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” dated February 11, 2000, Section 11, “Assessment of Risk Resulting from Performance of Maintenance Activities.” NUMARC 93-01, Section 11, references NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” Section 4.0, “Shutdown Safety Issues.”

The inspectors determined that while no specific contingency plan for the stator move was developed, the licensee did develop a contingency plan for the protection of spent fuel cooling. The inspectors concluded that no contingency plans were procedurally required to be developed by the licensee for the stator move and this was consistent with NUMARC 93-01.

No findings were identified.

.9 <u>(Closed) Unresolved Item 05000313/2013011-009, “Effectiveness of Material Handling Program”</u>

The Augmented Inspection Team identified an unresolved item associated with the licensee’s implementation of Procedure EN-MA-119, “Material Handling Program.” The inspectors determined that the design and test process applied to the crane did not conform to applicable procedures and standards. However, the inspectors 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.

a. <u>Observations and Findings</u>

<u>Introduction</u>. The NRC identified an apparent violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” applicable to both Unit 1 and Unit 2. Criterion V states, in part, that “activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings.” The licensee did not follow the requirements specified in Procedure EN-MA-119, in that, the licensee did not perform an adequate review of the subcontractor’s lifting rig design calculation, and the licensee did not conduct a load test of the lifting rig prior to use. The licensee initiated Condition Report CR-ANO-C-2013-00888 to capture this issue in its corrective action program. The licensee's corrective actions included repairing damage to the Unit 1 turbine deck, fire main system, and electrical system. In addition, changes were made to various procedures including Procedure EN-DC-114, “Project Management,” to provide guidance on review of calculations, quality requirements, and standards associated with third party reviews.

Description. The Augmented Inspection Team evaluated the effectiveness of measures to reduce the potential for a load drop consistent with the program requirements specified in Procedure EN-MA-119. They determined through interviews and documentation reviews, that the licensee's pre-outage evaluations were primarily focused on ensuring that the temporary hoisting assembly did not overload the existing plant structures. The Augmented Inspection Team also established that the project management organization considered the temporary crane installed by the subcontractor in the turbine building to be a temporary hoisting assembly. Procedure EN-MA-119, Section 5.2, "Load Handling Equipment Requirements," Item 7, stated, in part, that the following measures were to be used to establish the temporary hoisting assemblies' structural 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 are required to be inspected before and after the load test.

Section 5.2, Item 7, also included a note indicating that specially designed lifting devices may be designed and tested to other approved standards.

Based on the results of the Augmented Inspection Team's evaluation of the material handling program, the inspectors determined that the temporary hoisting assembly had not been load tested. The Augmented Inspection Team also established that although the note in Procedure EN-MA-119 allowed the use of alternate standards in lieu of load testing, the licensee could not identify objective evidence to demonstrate that an alternate approved standard had been used for the design and testing of the temporary hoisting assembly.

The inspectors, based on their independent review, determined that the temporary hoisting assembly design was based, in part, on an incorrect assumption, and the frame was not designed to support the stator load. The licensee concluded that one of the root causes for the temporary lift assembly collapse was that the sub-contractor's design did not ensure that the lift assembly north tower could support the loads anticipated for the lift.

In addition, the licensee, based on its root cause evaluation, concluded that the subcontractor failed to conduct the required load testing of their modified temporary lift assembly before its use. Specifically, the licensee concluded that:

- The north tower structure of the temporary lift assembly had not been subject to a load test or previously used in lifts of equal or greater capacity to that of the Unit 1 stator.

- Occupational Safety and Health Administration (OSHA) regulation CFR 29.1910.179 (k)(1) required that prior to initial use of a new or altered crane, the crane shall be tested to insure compliance with this section.

- The industry consensus standard, American Society of Mechanical Engineers NQA-1-2008, to which the subcontractor designed the temporary lift assembly, required load testing to ensure the structural and mechanical capacity of new or modified cranes.

Based on the results of their review, the inspectors concluded that the licensee failed to properly implement the requirements specified in Procedure EN-MA-119. Specifically, the inspectors identified that the licensee failed to:

- Adequately review and approve the subcontractor's design Calculation 27619-C1 as required by Section 5.2[7](a).

- Ensure that a load test of the assembly to at least 125 percent of the projected hook load was conducted, and that the assembly be load tested in all configurations for which it will be used, as required by Section 5.2[7](b).

The licensee initiated Condition Report CR-ANO-C-2013-00888 to capture this issue in its corrective action program. The licensee's corrective actions included repairing damage to the Unit 1 turbine deck, fire main system, and electrical system. In addition, changes were made to various procedures including Procedure EN-DC-114, "Project Management," to provide guidance on review of calculations, quality requirements, and standards associated with third party reviews.

<u>Unit 1:</u>

<u>Analysis</u>. The inspectors determined that the failure to implement the requirements of Procedure EN-MA-119 was a performance deficiency. Specifically, the licensee failed to: (1) independently review the subcontractor's calculation for the design of the temporary hoisting assembly as specified in Procedure EN-MA-119, Section 5.2[7](a), and (2) perform a load test of the assembly to 125 percent of the projected hook load and load test the assembly in all configurations for which it will be used, as required by Procedure EN-MA-119 Section 5.2[7](b). The finding was more than minor because it was associated with the procedural control attribute of the initiating event cornerstone, and adversely affected the cornerstone's objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The stator drop affected offsite power to Unit 1, resulting in a loss of offsite power for approximately 6 days and a loss of the alternate AC diesel generator. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, to evaluate the significance of the finding. Since the plant was shutdown, the inspectors were directed to Inspection Manual Chapter 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs," Checklist 4, dated May 25, 2004. Using Appendix G, Attachment 1, Checklist 4, the inspectors concluded that this finding degraded the licensee's ability to add reactor coolant system inventory when needed since a loss of offsite power occurred, and therefore, this finding required a detailed risk analysis. A shutdown risk model was developed by modifying the at-power Arkansas Nuclear One Unit 1 standardized plant analysis risk (SPAR) model, Revision 8.19. The NRC risk analyst assessed the significance of shutdown events by calculating an instantaneous conditional core damage probability. The results were dominated by two sequences. The largest risk contributor (approximately 97 percent) was from a failure of the emergency diesel

generators without recovery. The second largest risk contributor was the failure to recover decay heat removal. The result of the analysis was an instantaneous conditional core damage probability of 3.8E-4; therefore, this finding was preliminarily determined to have high safety significance (Red). Refer to Attachment 2 for the Unit 1 outage detailed risk evaluation.

This finding had a cross-cutting aspect in the area of human performance associated with field presence, because the licensee did not ensure adequate supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, the licensee did not provide a sufficient level of oversight in that, the requirements in Procedure EN-MA-119, for design approval and load testing of the temporary hoisting assembly, were not followed [H.2].

Unit 2:

Analysis. The inspectors determined that the failure to implement the requirements of Procedure EN MA-119 was a performance deficiency. Specifically, the licensee failed to: (1) independently review the subcontractor's calculation for the design of the temporary hoisting assembly as specified in Procedure EN-MA-119, Section 5.2[7](a), and (2) perform a load test of the assembly to 125 percent of the projected hook load and load test the assembly in all configurations for which it will be used, as required by Procedure EN-MA-119 Section 5.2[7](b). The finding was more than minor because it was associated with the procedural control attribute of the initiating event cornerstone, and adversely affected the cornerstone's objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The stator drop caused a reactor trip on Unit 2 and damage to the fire main system which resulted in water intrusion into the electrical equipment causing a loss of startup transformer 3. This resulted in the loss of power to various loads, including reactor coolant pumps, instrument air compressors, and the safety-related Train B vital electrical bus. The inspectors used Inspection Manual Chapter 0609, Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, and Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to evaluate the significance of the finding. Since this was an initiating event, the inspectors used Exhibit 1 of Appendix A and determined that Section C, "Support System Initiators," was impacted because the finding involved the loss of an electrical bus and a loss of instrument air. The inspectors determined that Section E, "External Event Initiators," of Exhibit 1 should also be applied because the finding impacted the frequency of internal flooding. Since Sections C and E were impacted, a detailed risk evaluation was required. The NRC risk analyst used the Arkansas Nuclear One, Unit 2 Standardized Plant Analysis Risk Model, Revision 8.21, and hand calculation methods to quantify the risk. The model was modified to include additional breakers and switching options, and to provide credit for recovery of emergency diesel generators during transient sequences. Additionally, the analyst performed additional runs of the SPAR model to account for consequential loss of offsite power risks that were not modeled directly under the special initiator. The largest risk contributor (approximately 96 percent) was a loss of all feedwater to the steam generators, with a failure of once-through cooling. The result of the analysis was a conditional core damage probability of 2.8E-5; therefore, this finding was preliminarily determined to have substantial safety significance (Yellow). Refer to Attachment 3 for the Unit 2 at-power detailed risk evaluation.

This finding had a cross-cutting aspect in the area of human performance associated with field presence, because the licensee did not ensure adequate supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, the licensee did not provide a sufficient level of oversight in that, the requirements in Procedure EN-MA-119, for design approval and load testing of the temporary hoisting assembly, were not followed [H.2].

Enforcement (Unit 1 and Unit 2). Title 10 of the Code of Federal Regulations (CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Quality Procedure EN-MA-119, "Material Handling Program," Section 5.2[7], "Temporary Hoisting Assemblies," Step (a) states, in part, that vendor supplied temporary overhead cranes or supports, winch-driven hoisting or swing equipment, and other assemblies are required to be designed or approved by engineering support personnel. The design is required to be supported by detailed drawings, specifications, evaluations, and/or certifications. Quality Procedure EN-MA-119, "Material Handling Program," Section 5.2[7] "Temporary Hoisting Assemblies," Step (b) states, in part, that the assembly shall be designed for at least 125 percent of the projected hook load and should be load tested and held for at least five minutes at 125 percent of the actual load rating before initial use. The assembly shall be load tested in all configurations for which it will be used.

Contrary to the above, on March 31, 2013, the licensee did not accomplish the stator lift and move, an activity affecting quality, as prescribed by documented instructions and procedures. Specifically:

a. The licensee approved a design for the temporary hoisting assembly that was not supported by detailed drawings, specifications, evaluations, and/or certifications. In addition, the temporary hoisting assembly was not adequately designed for at least 125 percent of the projected hook load. The licensee failed to identify the load deficiencies in vendor Calculation 27619-C1, "Heavy Lift Gantry Calculation," and the incorrectly sized component in the north tower structure of the temporary hoisting assembly.

b. The licensee failed to perform a load test in all configurations for which the temporary hoisting assembly would be used.

As a result, on March 31, 2013, while lifting and transferring the main generator stator, the temporary overhead crane collapsed, causing the 525-ton stator to fall on and extensively damage portions of the plant.

For Unit 1:

The Unit 1 finding has been preliminary determined to be of high safety significance (Red) and will be treated as an apparent violation and tracked as AV 05000313/20130012-004; "Unit 1 - Failure to Follow the Materials Handling Program during the Unit 1 Generator Stator Move."

For Unit 2:

The Unit 2 finding has been preliminary determined to be of substantial safety significance (Yellow) and will be treated as an apparent violation and tracked as AV 05000368/20130012-005; "Unit 2 - Failure to Follow the Materials Handling Program during the Unit 1 Generator Stator Move."

.10 (Closed) URI 05000313/2013011-010, "Causes and Corrective Actions Associated with the Dropped Heavy Load Event"

The Augmented Inspection Team identified an unresolved item associated with the licensee's identified causes and planned corrective actions for the March 31, 2013, temporary crane failure. The root cause evaluation effort was still in progress at the conclusion of the inspection. The Augmented Inspection Team concluded additional follow-up inspection was necessary to assess the adequacy of the licensee's identified causes and corrective actions when completed.

Observations and Findings

Condition Report CR-ANO-C-2013-00888, documented the root cause evaluation for the "Unit 1 Main Turbine Generator Stator," drop that occurred on March 31, 2013. The licensee identified a total of two root causes and four contributing causes, with the two root causes and two of the four contributing causes being attributed to the contractor performance. The report was finalized on July 22, 2013.

The stator contractor, Siemens Energy, Inc. (Siemens), and their heavy lift subcontractor, Bigge Crane and Rigging Co. (Bigge), declined to participate on the root cause evaluation team. The root cause team concluded that, if it had full access to material, personnel, and records from the two vendors, the team might have identified additional contributing causes along with corrective actions. However, the root cause team did conclude that enough information was available to it and that information was sufficiently adequate to identify why the event occurred and to establish the associated corrective actions.

The root cause team evaluated a number of different areas, including: extent of condition, extent of cause, operating experience, safety culture, vendor oversight, and organizational and programmatic weakness. Actual nuclear safety and radiological safety were also evaluated. The licensee concluded that the event was mitigated by safety-related equipment and appropriate operator response. Control room operators, in both units, were able to respond and take necessary corrective actions to mitigate the effects of equipment damage from the stator drop. The structures, systems, and components for both units responded as designed with no significant challenge to nuclear or radiological safety.

The root causes were:

1. The root cause of the temporary lift assembly collapse was that the Bigge design did not ensure the lift assembly north tower could support the loads anticipated for the lift.

2. Bigge failed to perform required load testing of the temporary lift assembly prior to its use in accordance with OSHA regulation.

The four contributing causes were:

1. Siemens and Bigge inaccurately represented that the hoist assembly had been used at other electric power stations to lift components that exceeded the anticipated weight of the Unit 1 stator.

2. Siemens failed to provide adequate oversight and control of Bigge's performance.

3. Procedure EN-MA-119 does not provide clear guidance regarding independent reviews of special lift equipment.

4. Supplemental Project personnel lacked sufficient knowledge of OSHA and ASME NQA-1 application to temporary lift assemblies and accepted Bigge's assertion that load testing was not required based on a combination of engineering analysis and previous use.

The inspectors determined that the root causes did identify why the temporary hoisting assembly failed. The inspectors noted that contributing causes identified various inadequacies in procedures, oversight of the subcontractor by the primary contractor, and knowledge of applicable standards by supplemental personal. However, it was not clear to the inspectors that the root causes or contributing causes addressed the licensee's oversight of contractors. The NRC conducted an independent review of the event, and as part of its review of Unresolved Item 2013011-009, "Effectiveness of Material Handling Program," the NRC identified a cross-cutting aspect H.2, "Field Presence," associated with the licensee not ensuring adequate supervisory and management oversight of work activities, including contractors and supplemental personnel.

The licensee implemented appropriate corrective actions to ensure the subsequent lift of the dropped stator and the Unit 1 replacement stator were performed safely considering lessons-learned from the root cause evaluation. Actions were implemented to ensure the safety of personnel and equipment during the lift of the replacement stator from the train bay to the generator pedestal.

No findings were identified.

4OA6 Meetings, Including Exit

<u>Exit Meeting Summary</u>

On February 10, 2014, the inspectors presented the inspection results to Mr. J. Browning, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. Proprietary information was provided to the team and the information is being handled in accordance with NRC policies.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Browning, Site Vice President
J. McCoy, Engineering Director
D. Perkins, Maintenance Manager
L. Blocker, Nuclear Oversight Manager
D. James, Regulatory and Performance Improvement Director
S. Pyle, Regulatory Assurance Manager
N. Mosher, Licensing Specialist
C. O'Dell, Production Manager
R. Byford, Training Manager
B. Gordon, Projects and Maintenance Services Manager
T, Evans, Production General Manager
T. Sherrill, Chemistry Manager
R. Harris, Emergency Plan Manager
J. Tobin, Security Manager
P. Williams, Operations Manager
T. Chernivec, Performance Improvement Manager
B. Daibu, Design and Program Engineering Manager

NRC Personnel

K. Kennedy, Division Director (telephonically)
L. Willoughby, Senior Reactor Inspector
B. Latta, Senior Reactor Inspector
J. Melfi, Reactor Inspector
N. Okonkwo, Reactor Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000313/2013012-004	AV	Unit 1 - Failure to Follow the Materials Handling Program during the Unit 1 Generator Stator Move
05000368/2013012-005	AV	Unit 2 - Failure to Follow the Materials Handling Program during the Unit 1 Generator Stator Move

Opened and Closed

05000313;368/ 2013012-001	NCV	Failure to Adequately Develop and Implement Adequate Procedural Controls to Remediate the Anticipated Effects of Internal Flooding for Either Unit
05000368/2013012-002	FIN	Main Feedwater Regulating Valve Maintenance Practices

Opened and Closed

05000313/2013012-003	NCV	Failure to Scope Required Components in the Station's Maintenance Rule Monitoring Program

Closed

05000313/2013011-001	URI	Control of Temporary Modification Associated with Temporary Fire Pump
05000313;368/ 2013011-002	URI	Damage to Unit 1 and Unit 2 Structures, Systems and Components
05000313/2013011-003	URI	Procedural Controls Associated with Unit 1 Steam Generator Nozzle Dams
05000368/2013011-004	URI	Main Feedwater Regulating Valve Maintenance Practices
05000313:368/ 2013011-006	URI	Compensatory Measures for Firewater System Rupture
05000368/2013011-007	URI	Timeliness of Emergency Action Level Determination
05000313/2013011-008	URI	Effectiveness of Shutdown Risk Management Program
05000313/2013011-009	URI	Effectiveness of Material Handling Program
05000313/2013011-010	URI	Causes and Corrective Actions Associated with the Dropped Heavy Load Event

Discussed

05000313/2013011-005	URI	Flood Barrier Effectiveness

LIST OF DOCUMENTS REVIEWED

Calculations

NUMBER	TITLE	REVISION/DATE
27619-C1	Bigge - Heavy Lift Gantry - ANO Stator Replacement Project	0
83-D-1140-05	Flooding Potential Due to Sprinkler System 'F'	December 8, 1982
83-D-2038-01	Flooding Potential Due to Sprinkler System Actuation at Elev 317', 335' and 354'	December 8, 1982
83-D-2057-03	Corridor 2104 Flooding Chronology	October 19,1983

83E-0062-11	Ponding Level Estimation at Elev. 317'-0"	0
83E-0062-12	Ponding Evaluation Fire Zone 105-T & 144-D	1
83-E-0062-13	Summary Calc. 0 Flooding Depths Due to Fire Protection Discharges and Know Elevations of Safety Related Electrical Equipment	July 15, 1985
CALC-89-D-1011-05	OTSG Nozzle Dam Safety Evaluation	0
83-D-2057-03	Corridor 2104 Flooding Chronology	October 19, 1983

Procedures

NUMBER	TITLE	REVISION
1005.002	Control of Heavy Loads	25
1015.048	Shutdown Operations Protection Plan	9
2201.001	Standard Post Trip Action	13
2203.034	Fire or Explosion	14
1203.012H	Annunciator K09 Corrective Action	43
2304-262	Unit 2 Feedwater Control System LOOP A Calibration	12
COPD-24	Risk Assessment Guidelines	46
EN-DC-114	Project Management	14
EN-DC-150	Condition Monitoring of Maintenance Rule Structures	4
EN-FAP-OU-100	Refueling Outage Preparation and Milestones	5
EN-FAP-OU-105	Refueling Outage Execution	1
EN-HU-104	Engineering Task Risk & Rigor	3
EN-LI-102	Corrective Action Process	21
EN-MA-119	Material Handling Program	16
EN-MA-126	Control of Supplemental Personnel	15
EN-OU-108	Shutdown Safety Management Program	5
EN-OU-108	Shutdown Safety Management Program	6
EN-WM-104	Online Risk Assessment	7
OP-1104.032	Fire Protection Systems	75

OP-5120.504	OTSG Nozzle-Dam Training, Testing & Installation/Removal	6

Drawings

NUMBER	TITLE	REVISION
1000.028-A	Temporary Alteration Form –Fire Water System	024-00-0
83E3719	28 Inch OTSG Nozzle Dam	7
A-2441-20-1	Dirty Waste Drain Tank Item T-20 Shop Fabrication Details Bechtel for Arkansas Power	3
A-411	Radiation Zones Plant Elevation 317’0” 11-4	6
A-412	Radiation Zones Plant Elevation 335’0” 11-5	8
A-413	Radiation Zones Plant Elevation 354’0” 11-6	1
C-202	Auxiliary Building Plan at Elevation 335'-0”	14
C-2202	Auxiliary Building Plan at Elevation 335'-0”	15
E-001	Station Single Line Diagram	
E-2673, Sh. 12	Connection Diagram Terminal Box	4
E-2680, Sh. 3	Connection Diagram Feedwater and Condensate System Console 2CO2	13
E-2728, Sh. 2	Schematic Diagram Feedwater Control System Train A	10
E-2728, Sh. 4	Schematic Diagram Feedwater Control System Train A	11
E-383	Schematic Diagram Auxiliary Building Sump Pumps	5
E-389	Schematic Diagram - Dirty Liquid and Laundry Radwaste Drain Pumps	3
LW-321	Overflow Piping to flow Drain Dirty Waste Drain Tank T-20	1
M-002	Equipment Location Fuel Handling Floor Plan	24
M-003	Equipment Location Operating Floor Plan	40
M-004	Equipment Location Intermediate Floor Plan	37
M-005	Equipment Location Ground Floor Plan	36
M-006	Equipment Location Plan Below Grade	32
M-007	Equipment Location Sections A-A and F-F	18
M-008	Equipment Location Section B-B	32
M-009	Equipment Location Section C-C	13

M-010	Equipment Location Section D-D	14
M-011	Equipment Location Misc. Plans and Sections	15
M-0213, Sh. 1	Dirty Radioactive Waste Drainage & Filtration	60
M-0213, Sh. 2	Laundry Waste and Containment & Aux Building Sump Drainage	28
M-0215	Gaseous Radioactive Waste	
M-0219, Sh. 1	Fire Water	83
M-0262, Sh. 4	Piping & Instrument Diagram Areas H.V.A.C. Aux. Bldg. - Rad. Waste	3
M1-H-35	Sodium Thiosulfate Stg Tank - 99” ID 35'-11” on Side	3
M-2001-N1-71, Sh. 1	Loop “A” FWCS Demand	0
M-2002	Equipment Location Fuel Handling Floor Plan	30
M-2003	Equipment Location Operating Floor Plan	53
M-2004	Equipment Location Intermediate Floor Plan	24
M-2005	Equipment Location Ground Floor Plan	39
M-2006	Equipment Location Plan Below Grade	40
M-2007	Equipment Location Section A-A & F-F	17
M-2008	Equipment Location Section B-B	20
M-2009	Equipment Location Section C-C	14
M-2010	Equipment Location Section D-D	16
M-2011	Equipment Location Misc. Plans & Sections	19
M-2044	Plant Design Drawing Area 24 Containment Auxiliary Building Plan at Elev. 354’-0” to 372’-0”	32
M-2045	Plant Design Drawing Area 24 Containment Auxiliary Building Plan at Elev. 335’-0” to 354’-0”	45
M-2046	Plant Design Drawing Area 24 & 26 Containment Auxiliary Building Plan at Elev. 335’-0” 3	26
M-2047	Plant Design Drawing Area 24 Containment Auxiliary Building Section A24-A24	34
M-2048	Plant Design Drawing Area 24 Containment Auxiliary Building Section B24-B24	33
M-2049	Plant Design Drawing Area 24 Containment Auxiliary Building Section C24-C24	32

M-2050	Plant Design Drawing Area 24 Containment Auxiliary Building Section D24-D24 & J24-J24	30
M-2063	Plant Design Drawing Area 26 Containment Auxiliary Building Plan Above Grade	23
M-2064	Plant Design Drawing Area 26 Containment Auxiliary Building Plan Below Grade	23
M-2065	Plant Design Drawing Area 26 Containment Auxiliary Building Misc. Plans & Sections	13
M-2066	Plant Design Drawing Area 26 Containment Auxiliary Building Section A26-A26	24
M-2067	Plant Design Drawing Area 26 Containment Auxiliary Building Misc. Sections	30
M-2119	Piping and Instrument Diagram, Unit 1/Unit 2, Fire Water, Sheet 1	83
M-2201-229, Sh. 06	2CO2 Wiring Diagram	21
M-2201-229, Sh. 10	2CO2 Wiring Diagram	20
M-2204, Sh. 1	Piping & Instrumentation Diagram Condensate and Feedwater	98
M-2204, Sh. 2	Piping & Instrumentation Diagram Condensate and Feedwater	82
M-2204, Sh. 3	Piping & Instrumentation Diagram Condensate and Feedwater	46
M-2204, Sh. 4	Piping & Instrumentation Diagram Condensate and Feedwater	67
M-2204, Sh. 5	Piping & Instrumentation Diagram Condensate and Feedwater	14
M-2213, Sh. 1	Liquid Radioactive Waste System	60
M-2213, Sh. 2	Liquid Radioactive Waste System	49
M-2213, Sh. 3	Liquid Radioactive Waste System	13
M-2213, Sh. 4	Liquid Radioactive Waste System - Auxiliary Building Elevation 317'-0”	15
M-2213, Sh. 5	Liquid Radioactive Waste System - Auxiliary Building Elevation 335'-0”	15
M-2213, Sh. 6	Liquid Radioactive Waste System - Auxiliary Building Elevations 354'-0” & 372'-6”	15

M-2213, Sh. 7	Liquid Radioactive Waste System - Auxiliary Building Elevations 385'-0", 404'-0" & 422'-0"	5
M-2219	Piping and Instrument Diagram, Fire Water, Sheet 1	61
M-2219	Piping and Instrument Diagram, Outside Fire Water, Unit 1 One/Unit Two, Sheet 5	50
M-2219	Piping and Instrument Diagram, Fire Water, Sheet 1	61
M-2219	Piping and Instrument Diagram, Outside Fire Water, Unit 1 One/Unit Two, Sheet 5	50
M-2219, Sh. 1	Fire Water	1

Work Orders

280093	272329	52355991	52380738	50234186-01

Condition Reports Reviewed

CR-ANO-C-2013-01072	CR-ANO-C-2013-00888	CR-ANO-C-2013-01962
CR-ANO-1-2013-00917	CR-ANO-C-2013-01074	CR-ANO-C-2013-00891
CR-ANO-1-2013-00132	CR-ANO-1-2013-01028	CR-ANO-1-2013-01286
WT-WTANO-2013-00039	CR-ANO-2-2012-01432	

Condition Reports Generated During the Inspection

CR-ANO-C-2013-01985	CR-ANO-1-2013-01286	CR-ANO-C-2013-01304
CR-ANO-2-2013-00423	CR-ANO-2-2013-01945	

Miscellaneous

NUMBER	TITLE	REVISION/ DATE
1104.032	Fire Protection Systems	75
1CAN111202	Flooding Walkdown Report - Entergy Response to NRC Request for Information (RFI) Pursuant to 10 CFR 50.54(f) Regarding the Flooding Aspects of 0Recommendation 2.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident Aransas Nuclear One - Unit 1	November 27, 2012
1-OPG-002	Tank Volume Book	3

Miscellaneous

NUMBER	TITLE	REVISION/ DATE
2CAN111202	Flooding Walkdown Report - Entergy Response to NRC Request for Information (RFI) Pursuant to 10 CFR 50.54(f) Regarding the Flooding Aspects of 0Recommendation 2.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident Aransas Nuclear One - Unit 2	November 27, 2012
A1LP-AO-FPS	Fire Protection Systems	12
EC-0044229	Provide Flooding Protection of Room 83 and Room 2079 (Unit 1 and Unit 2 Void Areas) Procedures 1203.025 and 2203.008 for Natural Emergencies	0
Engineering Review	General Flooding of Unit 1 Aux Building	April 21, 2013
ER-981203E101	Engineering Evaluation of ANO-1 Steam Generator Nozzle Dams	December 7, 1998
ER-991909	Engineering Request – Connect Temporary Pump to Fire System Test Header	E301-0
ER-991909	Temporary Fire Pump Alteration	E101-0
ER-991909	Temporary Fire Pump Alteration	E101-1
ER-991909	Temporary Fire Pump Alteration	E101-2
ER-ANO-2002-1223-001	Evaluation for PM requirements for Decay Heat Vaults Level Switches	October 20, 2002
Information Notice No. 87-49	Deficiencies in Outside Containment Flooding Protection	October 9, 1987
Letter	Letter, Phillps to Giambusso, Flooding of Safety Related Equipment	October 20, 1972
LIC-068-27	Pipe Rupture Leakage Criteria	June 20,1988
Operator Round Data	Waste Control Operator Rounds, March 20-April 16, 2013	
PMCD 2002-3701-P101	PM Evaluation for DHR Room Flood Alarm Level Switches	February 20, 2003
	ANO Stator Replacement Lift Plan letter from: Bigge Crane & Rigging Co. to: Siemens Entergy	February 8, 2013
	EN-S Nuclear Management Manual, 50.59 Review Form-Attachment 9.1	055-06-0

Miscellaneous

NUMBER	TITLE	REVISION/ DATE
	Repetitive Maintenance Task, Calibration of PDT4410	
OPS-A3	Unit 1 WCO Log sheet	22
	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	
	Unit 1 Outage schedule	0
	EOOS Chart, ANO Unit 2,	July 25, 2013
P.O. 31028-0159-PO	Purchase Order for Replacement of Cubicle for Unit 1-A2 Switchgear NSR/PP	May17, 2013
TRM-U1	Technical Requirements Manual	44
TRM-U2	Technical Requirements Manual	52
2A-113_1.jpg	Picture of 2A-113 Breaker Door	
2A-113_3.jpg	Picture of 2A-113 Breaker Door	
	Fire water system status 4-2-13 0502	
	Fire water system status 4-3-13 0609	
	Fire water system status 4-3-13 1109	
	Fire water system status 4-3-13 1800	
	Fire water system status 4-4-13 0451	
	Fire water system status 4-4-13 1800	
	Fire water system status 4-7-13 0600	
	Fire water system status 4-11-13 1245	
	Fire water system status 4-12-13 0400	
	Fire water system status	
	Log Entries Report for Fire Water up to 4-12-13 0400	
	Sequence of Events up to 4-12-13	

Miscellaneous

NUMBER	TITLE	REVISION/ DATE
	Tagout 1R24-1 - FS-009-B-FS RUPTURE with P&ID Markup	
	Tagout 1R24-1 - FS-009-C-FS RUPTURE with P&ID Markup	
	Tagout 1R24-1 - FS-009-D-FS RUPTURE and 2C23-1 – FS 019-2HR-36 with P&ID Markup	
	Tagout 1R24-1 - FS-009-FS RUPTURE with P&ID Markup	

Vendor Documents

NUMBER	TITLE	REVISION
TDF130 0320	Fisher Control Systems Instruction Manual Actuators Types 470, 471, 475 & 478 Series	5
TDG200 0080	For Model 3172 Aux Bldg Sump Pumps	
TDO045 210	OMEGA Level Switch Series LV-70 - Maintenance Section	
TDR340.0060	Installation and Maintenance Instruction McCannaflow Flanges Ball Valves Class 150 & 300 1” Thru 4”	0

Engineering Information Records

NUMBER	TITLE	REVISION
DCP 94-2008	Feedwater Control Systems Upgrade	July 26,1995
ECT-44312-02	SU 1 A1 & A2 Live Bus Test	July 21, 2013
ECT-44312-03	Functional Testing for Breaker 2A-903	July 20, 2013
ECT-44312-04	Functional Testing for Breaker 2A-901	July 24, 2013
ECT–44312-05	Functional Testing for Startup Transformer #2 A-1 Feeder breaker A-111	July 8, 2013

System Training Manuals

NUMBER	TITLE	REVISION
STM 1-52	Dirty Liquid Radwaste	7
STM 2-33	System Training Manual Alternate AC Diesel Generator	22
STM 2-69	System Training Manual Feedwater System Control	13
STM 2-19	System Training Manual Main Feedwater System	14

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Unit 1
Outage Detailed Risk Evaluation
(Phase 3 Risk Assessment Loss of Offsite Power)

Revision 1b

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1.0 Introduction

On March 31st 2013, at 7:50 am, Arkansas Nuclear One Unit 1 (ANO1) experienced a loss of offsite power (LOOP). This LOOP event occurred because while lifting and transferring the Unit 1 main generator stator to the train bay, the hoist assembly failed. The dropped stator fell on to the turbine deck and into the train bay. This event resulted in multiple damages in the turbine building including damage to electrical buses supplying offsite power to Unit 1, and damage to the fire suppression piping.

At the time of this event, Unit 1 was in a refueling outage. It had been shutdown for approximately 7 days. Fuel was in the reactor vessel, the reactor cavity was flooded up, and both trains of decay heat removal system were in service. With the loss of offsite power, both Unit 1 emergency diesel generators (EDG) started and loaded their respective buses. Decay heat removal was quickly restored. Once decay heat removal was restored the unit was quasi stable, with no offsite power available due to damage to the non-vital electrical buses, with EDGs powering the vital busses and the decay heat removal system operating and providing decay heat removal to the reactor vessel.

Dropping the generator stator caused the following damage:

- Offsite power was lost – it took six days to recover

- The station blackout diesel generator's (called the AAC) connection to the plant was severed rendering the ACC non-functional

- Fire watering piping was damaged requiring shutdown of the fire protection system. The damage to the piping also caused flooding in the Unit 1 and 2 structures with tens of thousands of gallons of water challenging critical equipment

2.0 Discussion of the Performance Deficiency

The licensee failed to properly implement Engineering Procedure EN-MA-119, "Material Handling Program." The following two examples are presented:

<u>The licensee failed to adequately review and approve Bigge Calculation 27619-C1 as required by Section 5.2[7] (a)</u>

Engineering Procedure EN-MA-119, Section 5.2[7] requires temporary hoisting assemblies to be designed or approved by Engineering Support Personnel (ESP). The design calculation did not adequately consider the loads that would be experienced by the lift. Entergy's review and approval process failed to identify the calculation deficiencies and the weak component in the north tower structure. Specifically, Entergy's ESP failed to adequately review and identify the flaw in Calculation 27619-C1 consistent with the requirements of procedure Section 5.2[7] (a) which states that temporary hoisting assemblies are required to be designed or approved by ESP.

The licensee failed to ensure that a load test of the assembly to at least 125 percent of the projected hook load or to another approved standard was performed as required by Section 5.2[7](b) and associated note.

3.0 Plant Conditions Prior to the Event

Plant equipment and conditions were as follows:

- Unit was in refueling outage with fuel in the reactor, head removed, and refueling canal flooded
- Estimated time to boil (TTB) was 11 hours
- Estimated time to core uncovery was 4 days
- Both trains of reactor shutdown cooling (SDC) were in service
- Plant electrical lineup was in a plant shutdown configuration to support maintenance and testing as follows:
    - 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.

4.0 Plant Conditions after Initiating Event Initiated

Time to boil was estimated at eleven hours and time to core uncovery without mitigation was estimated at four days.

The following equipment was unavailable after event initiation:

- Offsite power
- Station blackout diesel generator - ACC
- Fire water
- All balance of plant equipment
- Gravity feed from the borated water storage tank (BWST) as water level in the BWST was lower than water level in reactor coolant system (RCS)
- Instrument air (IA) was unavailable – the analyst assumed that all air operated valves failed in a safe direction, i.e., the systems IA supported remained available (Note: 1) the DHR heat exchanger bypass valves fail shut on loss of air, 2) the service water supply valve to the DHR heat exchanger fails full open on loss of air)
- Starting air compressors for the emergency generators
- Normal lighting

The following equipment was available after the event initiation to mitigate the event:

- Both emergency diesel generators and their respective electrical distribution systems
- Both decay heat removal trains (two pumps)
- Both high pressure injection (HPI) trains (three pumps)
- Reactor building spray systems – note these were not credited in the analysis, however, the non-crediting had no effect on the quantitative results

5.0 Significance Determination Process (SDP) Phase 2 Summary

No Phase 2 was conducted.

6.0 Initiation of a Phase 3 SDP Risk Assessment

A Phase 3 SDP risk assessment was performed by the Office of Nuclear Reactor Regulation (NRR).

The analysts used the following generic references in preparing the risk assessment:

- NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management." December 1991
- NUREG/CR-6883, "The SPAR-H Human Analysis Method." August 2005
- NUREG-1842, "Good Practices for Implementing Human Reliability Analysis." April 2005
- NUREG/CR-6595 Revision 1, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." October 2004
- INL/EXT-10-18533 Revision 2, "SPAR-H Step-by-Step Guidance." May 2011
- "RASP Manual Volume 1 – Internal Events," Revision 2.0 date January 2013
- NUREG/CR-1278, "Handbook of HRA with Emphasis on Nuclear Power Plant Applications." August 1983

The analyst used the following plant specific references:

- EOP: 1202.007, Degraded Power
- AOPs:
  - 1203.024, Loss of Instrument Air
  - 1203.028, Loss of Decay Heat Removal
  - 1203.050, Unit 1 Spent Fuel Pool Emergencies
- Calculation: 89-E-0017-01, Time to Boiling and Time to Core Uncovery after Loss of Decay Heat Removal, Unit 1, Revision 7

- Procedure: 1103.018, Maintenance of RCS Water Level

7.0 Development of the Model

No Low Power/Shutdown (LP/SD) SPAR model exists for ANO Unit 1. Therefore, the at-power ANO1 SPAR model was modified to allow analysis of the LOOP event. A new event tree (ET) was created to analyze the event.

This ET is shown in Figure A-1 of Appendix A. The ET was linked to a mix of existing at-power fault trees (FT) and new FTs, as applicable. The existing FTs were modified as necessary to appropriately describe system dependencies during shutdown conditions and the different success criterion. The ET and high level FTs are shown in Appendix A.

Modeling Assumptions

- PRA mission time is normally assumed to be 24 hours. However, after the event was initiated it took approximately six days to recovery offsite power. If the emergency diesel generators failed after running successfully for three days the time to core uncovery was over three days after loss of DHR. Thus the emergency diesel generator mission time was modified to 72 hours.

- The Division 2 normal AC power is from 4Kv bus A2. However, bus A2 was unavailable for maintenance and bus A4 was receiving power from 4Kv bus A3 via breaker A-310 and A-410. A model change was made to reflect this alternative alignment and the associated interlocks and their failure probabilities.

- As identified above, the Green train battery D06 had been disconnected from D02 bus. D02 DC bus was being fed from a battery charger supplied from Div. 1 AC power. With this arrangement, the Div. 2 DC system would (and did) de-energize on a loss of Div. 1 AC power. If the Div. 1 AC power is restored with an EDG start then Div.2 DC power would be (and was) restored. However, if the Div. 1 EDG did not restore AC power to the battery charger, the Div. 2 DC power would remain de-energized. The consequence of this is that without DC power from a Div. 1 battery charger the Div. 2 EDG would not start normally. In fact, during the event, the Div.2 EDG start was delayed about 10 seconds until the Div. 1 EDG restored Div.2 DC power. The model was modified to allow for a manual realignment of Div. 2 DC power directly to the Div. 1 battery. This human action (HFE) was given a failure probability of 4E-3 (DCP-XHE-XM-DD11D12). Notes: 1) An alternative means of re-energizing the Div. 2 DC system would be to restore the Div. 2 battery from its maintenance status. The licensee indicated that this could be accomplished in about 30 minutes once the problem and solution were identified and the decision made to proceed. This recovery method was not modeled as it is assumed that the failure probability of the primary method was adequately low to negate

the need for the additional recovery method. 2) Both EDGs can be manually started without DC power during a proceduralized process that the licensee estimates would take about 2 hours. This capability was not explicitly modeled as the analyst assumed that this procedure is adequately credited as part of the diesel recovery analysis incorporated into the event tree.

- As noted above, instrument air failed during the event. Without instrument air, there is no means to recharge the EDG start air receiver tanks. The receiver tanks have sufficient capacity for about 10 normal starts of the EDGs. Thus if the EDGs did not start initially, there would be a limited number of starts before the tanks deplete. This dependency was modeled.

- On loss of instrument air the DHR heat exchanger bypass valves fails full closed, i.e., in the safe direction. Also the service water supply valves to the DHR heat exchangers fail full open also in the safe direction. These attributes were not modeled.

- As discussed above, the RCS level at the beginning of the event was higher than the BWST level. Therefore, at the beginning of the event there was no capability to gravity feed the RCS from the BWST. The licensee asserted that they have capabilities to refill the Unit 1 BWST from the Unit 2 RWT. However, once the BWST was refilled RCS level would still be higher than the BWST level. However, if RCS boiling were to commence, then the level in the RCS would decrease. Level would decrease below the Unit 1 BWST level at which point level would allow gravity feeding of the Unit 1 RCS. However, boiling would cause the Unit 1 reactor building (i.e., containment) to pressurize. This elevated pressure would preclude gravity feed. The licensee could depressurize the reactor building. These capabilities are un-proceduralized and were not credited in the modeling.

- Time to boil (TTB) was changed from 8 hours to 11 hours. Time to core uncovery was changed from 3 to 4 days to 4 days. Both changes are based on revised calculations from the licensee. These changes had no impact on the HRA analysis. However, the change in the core uncovery time did lower the non-recovery probabilities marginally.

HRA Analysis

Shutdown operation is highly dependent on operator actions as most of the required actions are manual (e.g., initiating feed of the RCS). HRA analysis was conducted to properly characterize the required manual actions. The human error probabilities (HEPs) were calculated using the Low Power Shutdown SPAR-H worksheets from NUREG/CR-6883, “The SPAR-H Human Reliability Analysis Method” and INL/EXT-10-18533 and SPAR-H Step-by-Step.” Consideration was given to the following:

- available time to perform the manual actions,
- stress levels of the crew during the event,
- complexity of the diagnoses and required recovery actions,
- crew experience and applicable and relevant training,
- quality and thoroughness of procedures,
- ergonomics,
- fitness of duty issues, and
- available work processes

Table 1 shows a summary of the dominant HEPs, a detailed discussion of the HEPs is given in Appendix B.

In addition to the calculation of specific HEPs for this condition, sequences or cutsets which involved multiple operator actions were examined for human action dependency. For the dominant HEPs no dependent couplets were found.

In addition, the cutsets were reviewed to find those that contained two or more HEPs in a single sequence of cutset. For those cutset with multiple HEPs, the HEPs were reviewed to determine if the product of the HEPs was less than 1E-6. For those cutsets a floor, or cutoff, was applied as directed by *RASP Manual Volume 4 – Shutdown Events*, Revision 1 Appendix B. Because of the long times to core damage, a cutoff of 1E-7 was applied. This conservative assumption did not materially affect the results.

Normal lighting was impacted by the LOOP. This could have an impact on the ability of the equipment operators to perform tasks outside of the main control. This impact was not assessed.

A detailed description of the HEPs is given in Appendix B.

Table 1
Summary of Dominant HRA Results

Human Error Event	Description	Time Needed	Time Available	Mean Diagnosis HEP	Mean Action HEP	Total Mean HEP
SD-XHE-D-LOSDC	Operator Fails to Diagnose Loss of SDC before boiling	5 minutes	11 hours	2E-5	n/a	2E-5
SD-XHE-XL-LOSDC	Operator Fails to Recover Loss of SDC before Boiling	30 minutes	11 hours	n/a	4E-4	4E-4
SD-XHE-XL-MINJ	Operator Fails to Inject (AC power available) before Level Reaches TAF	30 minutes	4 days	n/a	2E-5	2E-5
SD-XHE-XL-LPR	Operator Fails to Initiate Low Pressure Recirc	1 hour	5 days	2E-5	2E-4	2.2E-4
SD-XHE-XM-BWST	Operator Fails to Refill BWST during Shutdown	10 hour	5 days	n/a	2E-5	2E-5
DCP-XHE-XM-DD11D12	Operator Action to Align 125VDC Panel D11 to Feed 125VDC Panel D21	1 hour	4 hours	2E-3	2E-3	4E-3

8.0 Conditional Core Damage Probability (CCDP) Assessment Results

A detailed Phase 3 Significance Determination Process risk analysis was performed consistent with NRC Inspection Manual Chapter (IMC) 0609 Appendix G. Step 4.3.8 of this procedure directs the analyst to assess the significance of shutdown events by calculating an instantaneous conditional core damage probability (ICCDP). (Throughout this assessment, the analyst has used the terminology of CCDP instead of ICCDP for simplicity.) This assessment was performed by setting the initiating event frequency (IEF) for loss of offsite power to 1.0 and all other IEF to zero. The above described SPAR model was evaluated using the SAPHIRE code version 8.0.9.0.

As this SDP evaluates an actual event in which no external events occurred, there was no risk from external events. As discussed in the above paragraph, this would include setting any external event IEF to zero.

The truncation limit was set at 1E-16.

The result of the CCDP analysis is 3.8E-4; based on these results the finding is preliminary Red. The top cutsets are in Appendix C. The analyst did not perform uncertainty analysis.

Table 2
CCDP Results

Sequence	Point Estimate	Cut Set Count
4	1.6E-5	6784
6	2.1E-8	2072
8	3.3E-7	13225
11	1.0E-7	553
13	4.3E-9	79
15	7.2E-9	359
19	3.7E-4	3955
Total	**3.8E-4**	27027

The results are dominated by two sequences. The largest contributor is from Sequence 19 which comprises a failure of the emergency diesel generators (EDG) without recovery. Both the EDG and EDG non-recovery failure probabilities were calculated using the standard SPAR methods and models. Sequence 4 is also a significant contributor. Sequence 4 cutsets are dominated by failure to recover DHR.

The numeric results above quantify to a preliminary Red finding. However, given the time to core damage, recovery may be possible with temporary systems such as B.5.b equipment. The analyst is unaware of procedures or training to cool the RCS during these conditions. In addition, condition in the reactor building may become difficult if not life threatening once boiling begins. In conclusion, some credit for these types of actions may be warranted. However, neither SPAR-H nor any other HRA method was ever intended to quantify these types of scenarios. However, using SPAR-H yields failure probabilities between 0.1 and 0.5. If significant credit were given, this could reduce the finding into the Yellow range.

9.0 Conditional Large Early Release Probability (CLERP) Assessment

The figure of merit for this analysis is incremental conditional large early release probability (ICLERP). This ICLERP analysis is based on the method for shutdown described in NUREG/CR-6595 Revision 1, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," dated 10/2004. This report supplies simplified containment event trees (CET) to determine if the core damage sequence contributes to LERF. NUREG/CR-6595 presents its analysis in terms of LERF, which is interpreted here as ICLERP.

NUREG/CR-6595 defines LERF as "… the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects." This is identical to the definition of LERF in IMC 0609 Appendix H. Figure 4.2 (PWR Large Dry and Sub-atmospheric Containment Event Tree) from NUREG/CR-6595 is applicable to the ANO1 event.

This event occurred seven days after shutdown. The earliest core damage could occur would be four days after event initiation. Thus core damage would not occur until 11 days after shutdown. Based on this time and the recommended approach given by NUREG/CF-6595 no large early release could occur.

10.0 Sensitivity Analysis

Several sensitivity cases were conducted to further understand the event risk significance. The cases are described below.

Case 1: Loss of Instrument Air

The LOOP event on Unit 1 in combination with the partial LOOP in Unit 2 combined to cause a loss of instrument air on Unit. There does not appear to be any impact on Unit 1 from the loss of air. However, instrument air was being supplied to the steam generator nozzle dams. If the nozzle dams had failed, water level could have drained to the bottom of the steam generator openings. The nozzle dam design appears to preclude a significant inventory on loss of air. The design limits the leakage to 2 gpm on each nozzle dam. With several hundred thousand gallons of water above the nozzle dams this leakage rate is insignificant.

Case 2: HRA No Cutoff

A case was conducted to verify the sensitivity of the results to the cutoff value. This case was run with truncation level of 1E-16. The calculated CCDP was 1.6E-4. This indicates that the cutoff implementation is a second order effect only.

Sequence	Point Estimate
4	1.6E-05
6	1.7E-08
8	3.3E-07
11	6.0E-10
13	6.1E-13
15	1.8E-10
19	3.7E-04
Total	**3.8E-04**

Case 3: DC Flooding

The stator drop severed a fire water header pipe. It took approximately 45 minutes to stop this leakage. Before the leakage was stopped, water accumulated into the Unit 1 and 2 turbine buildings where it caused a small Unit 2 kV fire/explosion. This caused a loss of offsite power to one division of Unit 2 AC power which was mitigated by the associated emergency diesel generator. Water also started to accumulate into the Unit 1 SDC/DHR B pump vault. If this accumulation continued it could have failed the pump. Potentially it could have impacted other Unit 1 equipment. Sensitivity cases were conducted with various flooding probabilities and various combinations of impacted equipment. Those combinations and their impacts are presented in the below table. These analyses assume that the flooding could not impact the Unit 1 emergency diesel generator or their associated 4kV switch gear and 480 v MCCs.

This analysis shows that if the flooding had not been terminated in a timely manner it could have had a significant impact on plant safety.

Impacted Equipment	**CCDP**	
	Flood Probability = 0.1	**Flood Probability = 1.0**[1]
A LPI/SDC/DHR pump	4E-4	5E-4
B LPI/SDC/DHR pump	8E-4	4E-3
Both LPI/SDC/DHR pumps	1E-3	5E-2
A single HPI pump (either A, B or C)	no impact	no impact
Any combination of two HPI pumps	no impact	no impact
All three HPI pumps	no impact	no impact
All of HPI and SDC/DHR	1E-3	1E-1

Notes:

1) If the associated basic events are set to True instead of 1.0 the CCDPs are somewhat lower as would be expected.

2) These sensitivity cases were run with truncation set to 1E-8.

Case 4: Impact of Loss of EDG Starting Air Compressors

The LOOP caused a loss of normal EDG starting air. If multiple starts of the EDG were required this could impact the restoration of the emergency power. While it is difficult to quantify the change in the EDG non-recovery probability, it is straight forward to calculate the impact of non-recovery probabilities on the CCDP. The analyst assumed that the non-recovery probability was double from 4.0E2 (for 96 hours) to 8.0E-2. The new CCDP is 7.5E-4.

Case 5: Impact of EDG 2 in Maintenance

When the generator stator was dropped, the licensee was making plans to start maintenance on the Div. 2 emergency diesel generator. This maintenance was imminent. No licensee restrictions were in place to delay this maintenance until after the generator stator lifts had been completed. If this EDG maintenance had been started and sufficiently progressed to preclude restoration this would have significantly increased the risk. This sensitivity case places the Div. 2 EDG in maintenance. The new CCDP is 3.5E-3.

Appendix A: Model Figures

Figure A-1: Loss of Offsite Power Event Tree

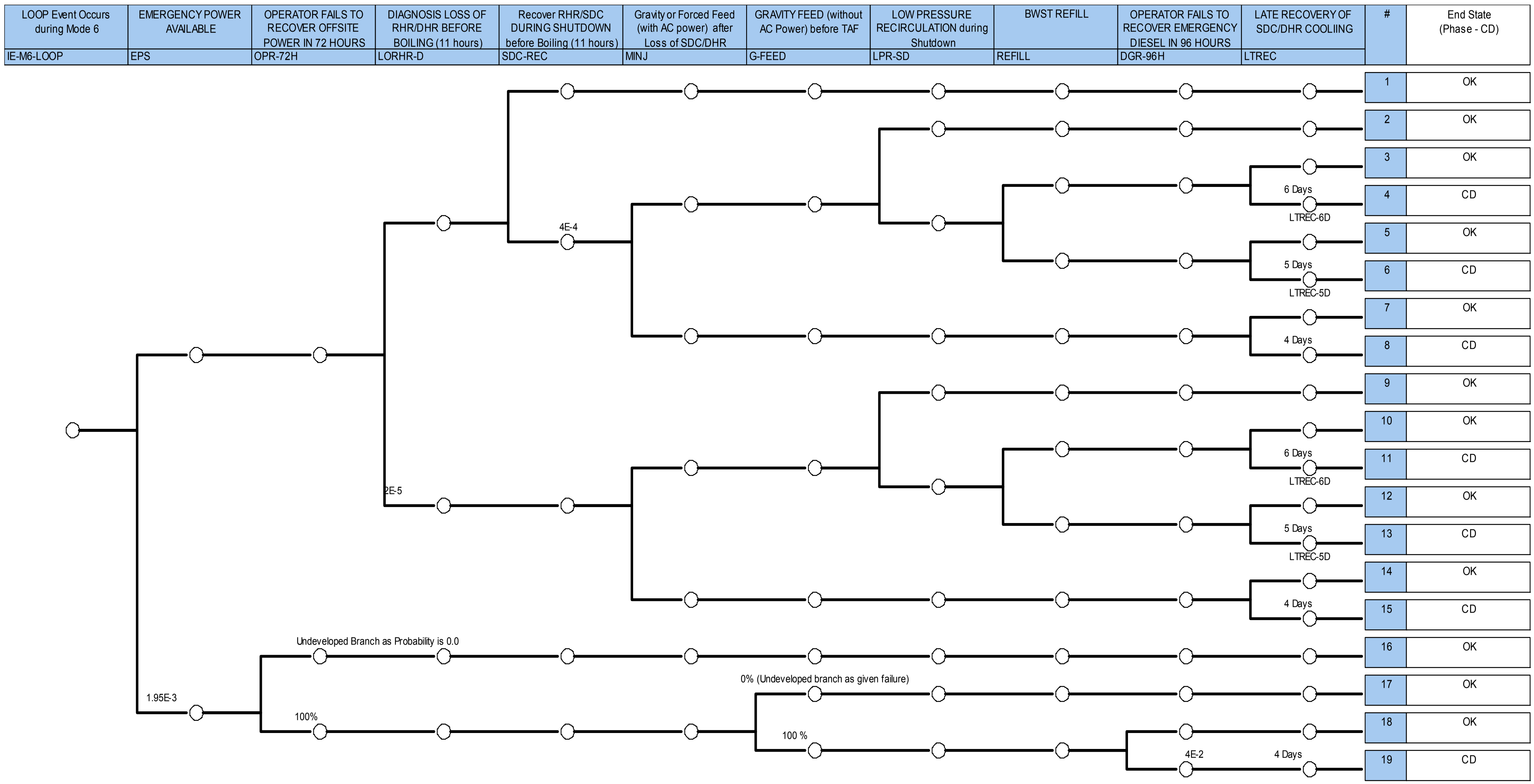


Figure A-2: Emergency Power Failure Fault Tree

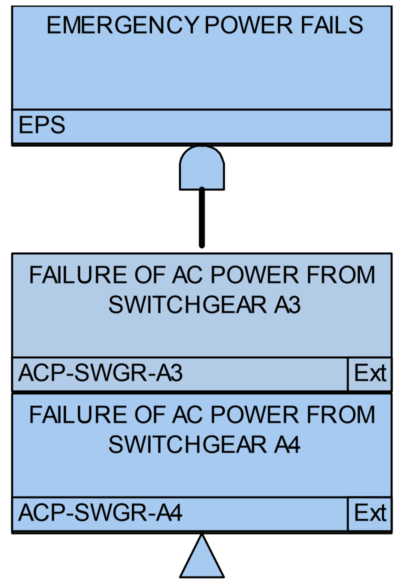
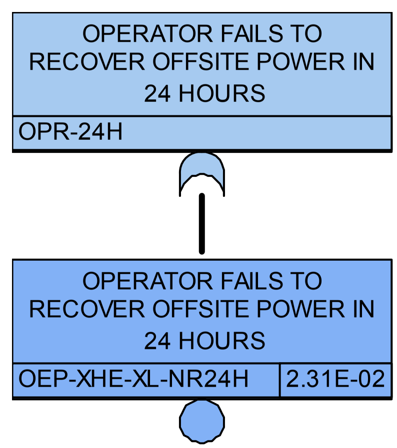


Figure A-3: Offsite Power Recovery Fault Tree



Note that the non-recovery probability was set to one in a change set

Figure A-4: Diagnose Loss of RHR/DHR Fault Tree

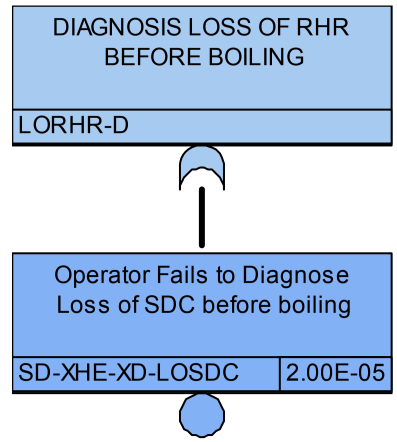


Figure A-5: Recovery RHR/SDC Fault Tree

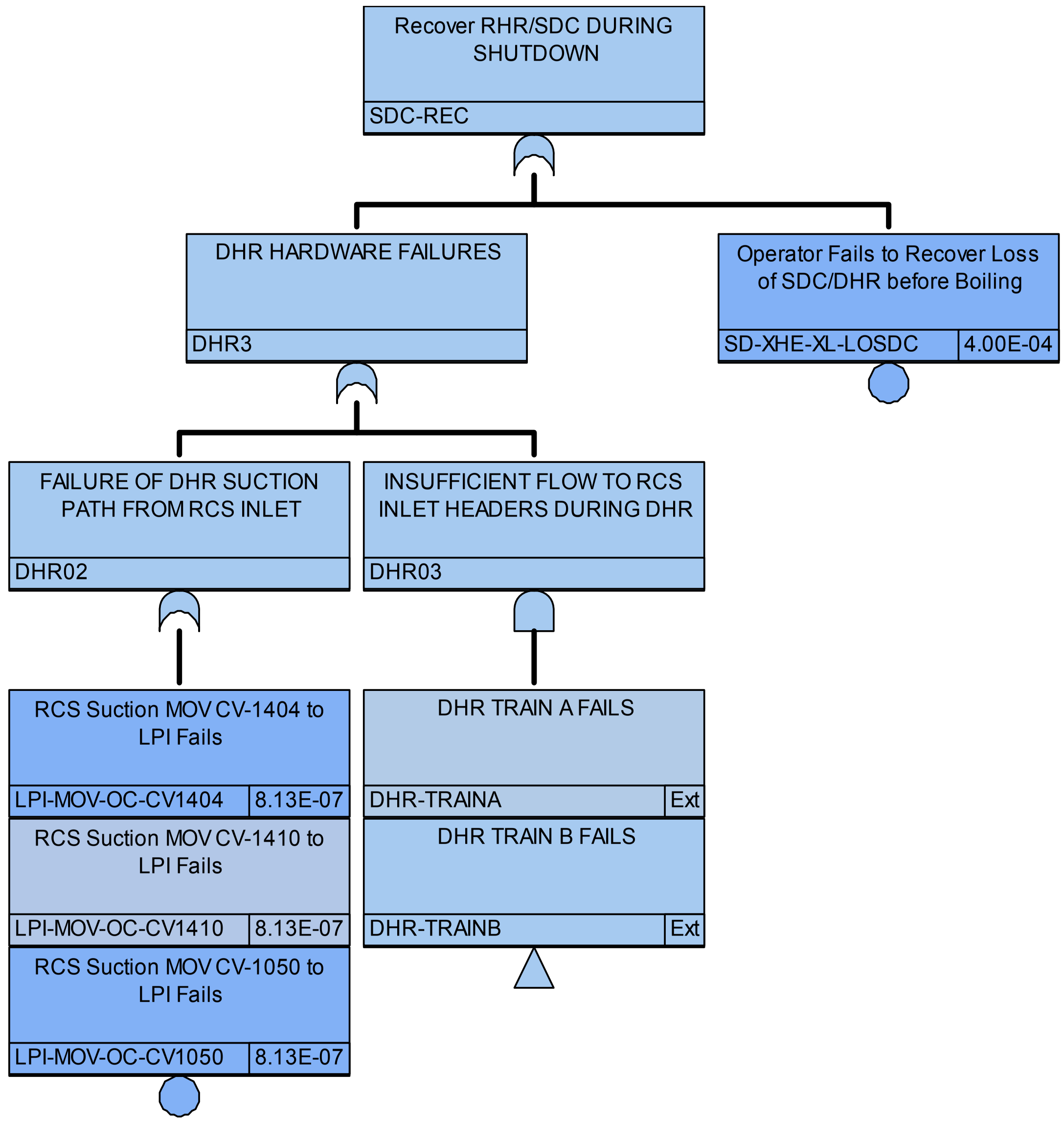
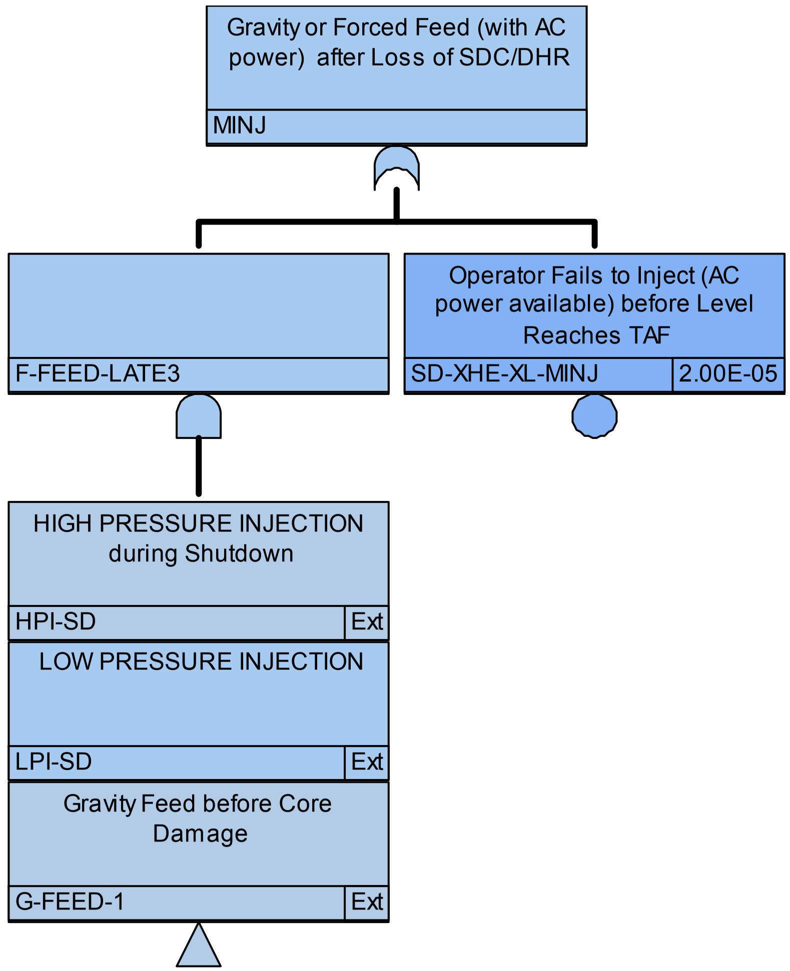
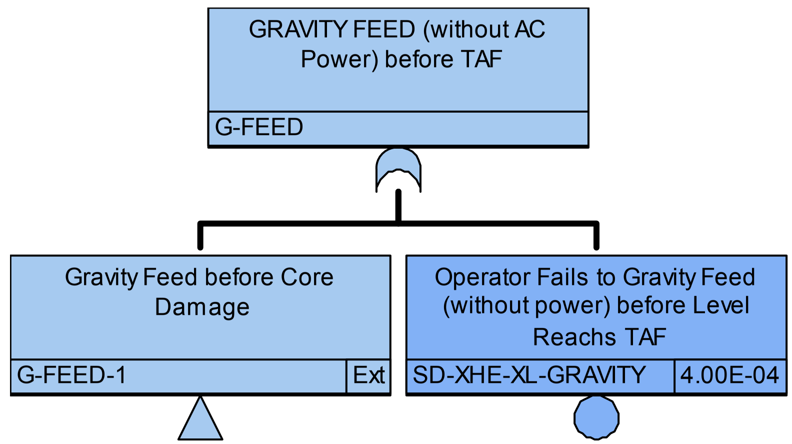


Figure A-6: Gravity and Forced Feed Fault Tree



Note the gravity feed portion of this FT is set to fail as gravity feed will not work because the physical level of the BWST is lower than the refueling canal

Figure A-7: Gravity Feed (without AC Power) Fault Tree



Note this FT is set to fail as gravity feed will not work because the physical level of the BWST is lower than the refueling canal

Figure A-8: Low Pressure Recirculation Fault Tree

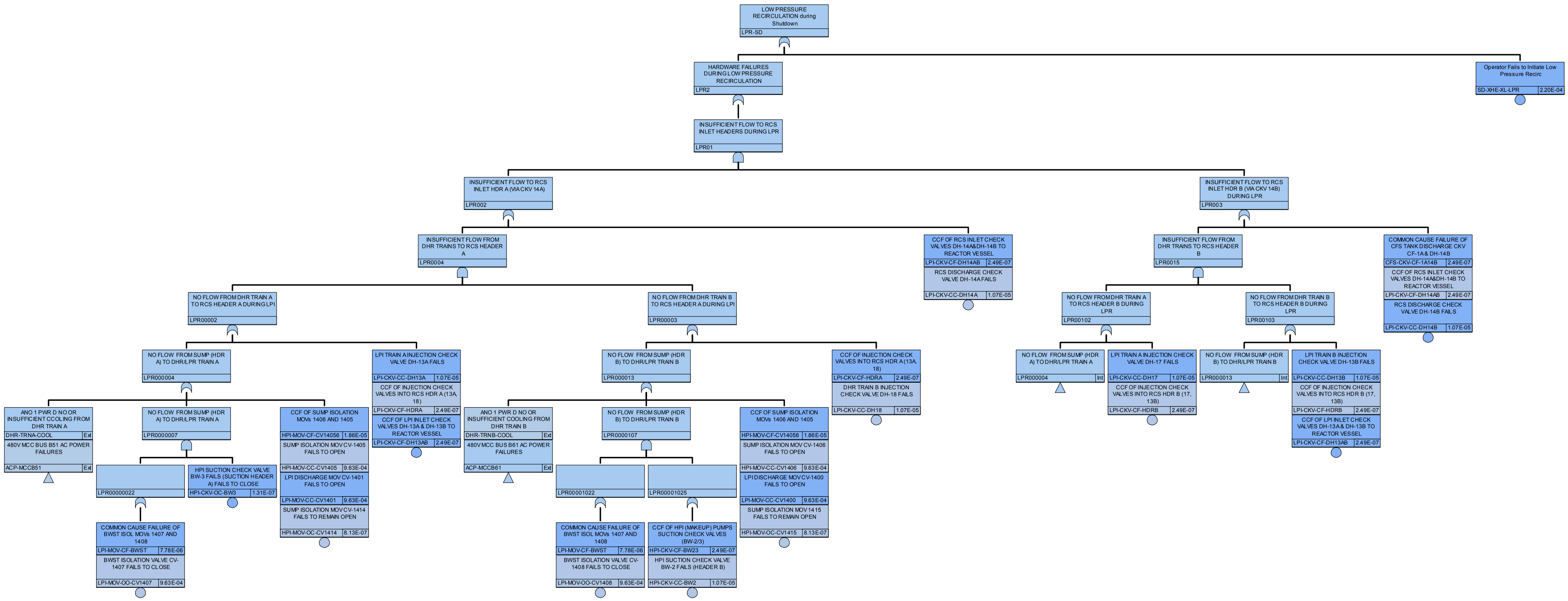


Figure A-9: BWST Refill Fault Tree

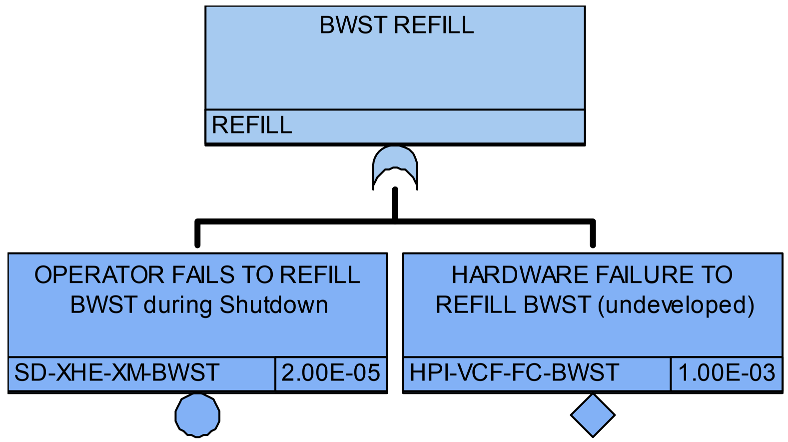


Figure A10: Diesel Generator Recovery Fault Tree

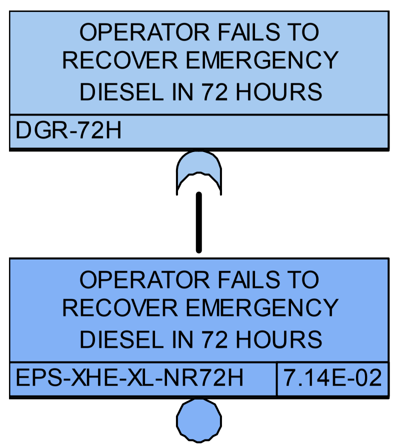
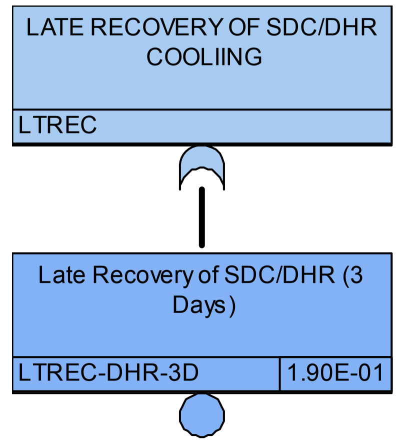


Figure A-11: SDC/DHR Late Recovery Fault Tree



Note the value of the late recovery basic event varies with the time available

Appendix B: HRA Analysis

Human Error Probabilities

A high level discussion of the Human Reliability Analysis (HRA) is presented above in Section 7 on Model Development. Also included above is a summary of the HRA results. The following discusses the Human Failure Events (HFE), the derivation of the in individual Human Error Probabilities (HEP). This HRA analysis was done consistent with the guidance of NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method," dated August 2005.

The Human Error Probabilities (HEPs) for this analysis were calculated using the Low Power Shutdown SPAR-H worksheets from NUREG/CR-6883. Consideration was given to the available time to perform the action, the stress levels of the crew during the event, complexity of the action, crew experience and applicable and relevant training, quality and thoroughness of procedures, ergonomics, fitness of duty issues, and the available work processes.

B1 Operator Fails to Diagnose Loss of SDC before Boiling

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: SD-XHE-XD-LOSDC
Basic Event Description: Operator Fails to Diagnose Loss of SDC before boiling

Part I. DIAGNOSIS WORKSHEET

PSFs	PSF Levels	Multiplier for Diagnosis	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		5 minutes required, 11 hours available
	Barely adequate time (≈2/3 Nominal)	10		
	Nominal time	1		
	Extra time (between 1 and 2 x nominal and > than 30 min)	0.1		
	Expansive time (> 2 x nominal and > 30 min)	0.01	X	
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately Complex	2		
	Nominal	1		
		0.5		
	Obvious diagnosis	0.1	X	Pump stop with loss of power is obvious
	Insufficient information	1		
Experience/ Training	Low	10		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		
	Incomplete	20		
	Available, but poor	5		
	Nominal	1	X	
	Diagnostic/symptom oriented	0.5		
	Insufficient information	1		
Ergonomics/HI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	2		
	Nominal	1	X	
	Good	0.8		
	Insufficient information	1		

		NHEP =	**2.00E-05**	
	Negative PSFs adjustment (≥3 negative PSFs)		**NA**	
		Final Diagnosis HEP	**2.00E-05**	

B2 Operator Fails to Recover Loss of SDC/DHR before Boiling

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: SD-XHE-XL-LOSDC
Basic Event Description: Operator Fails to Recover Loss of SDC before boiling

Part II. ACTION WORKSHEET

PSFs	PSF Levels	Multiplier for Action	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		30 minutes required, 11 hours available. SDC/DHR pumps are located in the containment one boiling occurs into containment operation of pumps will be effected
	Time Available is ≈ the time required	10		
	Nominal time	1		
	Time available is ≥ 5x the time required	0.1	X	
	Time available is ≥ 50x the time required	0.01		
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately	2	X	
	Nominal	1		
	Insufficient information	1		
Experience/Training	Low	3		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		.
	Incomplete	20		
	Available but poor	5		
	Nominal	1	X	
	Insufficient information	1		
Ergonomics/HMI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	5		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
		Final Action HEP	**4.00E-04**	

B3 Operator Fails to Inject (AC power available) before Level Reaches TAF

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: NMP1 Initiating Event: Basic Event: SD-XHE-XL-MINJ
Basic Event Description: Operator Fails to Inject after Level Reaches Scram Setpoint and before it Reaches TAF

Part II. ACTION WORKSHEET

PSFs	PSF Levels	Multiplier for Action	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		
	Time Available is ≈ the time required	10		
	Nominal time	1		
	Time available is ≥ 5x the time required	0.1		
	Time available is ≥ 50x the time required	0.01	X	
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		This assumes that condensate continues to run on loss of DC. If racking in core spray is required this would be moderate.
	Moderately	2		
	Nominal	1	X	
	Insufficient information	1		
Experience/Training	Low	3		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		.
	Incomplete	20		
	Available but poor	5		
	Nominal	1	X	
	Insufficient information	1		
Ergonomics/HMI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	5		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
		NHEP =	**2.00E-05**	
	Negative PSFs adjustment (≥3 negative PSFs)		**NA**	
		Final Action HEP	**2.00E-05**	

B4a Operator Fails to Diagnose Need for Low Pressure Recirc

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: SD-XHE-XL-LPR
Basic Event Description: Operator Fails to Initiate Low Pressure Recirc

Part I. DIAGNOSIS WORKSHEET

PSFs	PSF Levels	Multiplier for Diagnosis	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		Feed has been started therefore there is at least 24 hours to restart SDC
	Barely adequate time (≈2/3 Nominal)	10		
	Nominal time	1		
	Extra time (between 1 and 2 x nominal and > than 30 min)	0.1		
	Expansive time (> 2 x nominal and > 30 min)	0.01	X	
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately Complex	2		
	Nominal	1	X	
		0.5		
	Obvious diagnosis	0.1		
	Insufficient information	1		Scram setpoint is an obvious cue
Experience/ Training	Low	10		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		
	Incomplete	20		
	Available, but poor	5		
	Nominal	1	X	
	Diagnostic/symptom oriented	0.5		
	Insufficient information	1		
Ergonomics/HI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	2		
	Nominal	1	X	
	Good	0.8		
	Insufficient information	1		
		NHEP =	**2.00E-4**	
	Negative PSFs adjustment (≥3 negative PSFs)		**NA**	
		Final Diagnosis HEP =	**2.00E-4**	

B4b Operator Fails Action for Low Pressure Recirc

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: SD-XHE-XL-LPR
Basic Event Description: Operator Fails to Initiate Low Pressure Recirc

Part II. ACTION WORKSHEET

PSFs	PSF Levels	Multiplier for Action	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		
	Time Available is ≈ the time required	10		
	Nominal time	1		
	Time available is ≥ 5x the time required	0.1		
	Time available is ≥ 50x the time required	0.01	X	
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately	2		
	Nominal	1	X	
	Insufficient information	1		
Experience/Training	Low	3		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		.
	Incomplete	20		
	Available but poor	5		
	Nominal	1	X	
	Insufficient information	1		
Ergonomics/HMI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	5		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
		NHEP =	**2.00E-05**	
	Negative PSFs adjustment (≥3 negative PSFs)		**NA**	
		Final Action HEP	**2.00E-05**	

B5a Operator Fails Diagnoses for Aligning Alternate DC Power

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: DCP-XHE-XM-DD11D21
Basic Event Description: Operator Action to Align 125VDC Panel D11 to Feed 125VDC Panel D21

Part I. DIAGNOSIS WORKSHEET

PSFs	PSF Levels	Multiplier for Diagnosis	Selected PSF	Please note specific reasons for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		30 minutes required, aasumed 4 hour battery depletion time is time available.
	Barely adequate time (≈2/3 Nominal)	10		
	Nominal time	1		
	Extra time (between 1 and 2 x nominal and > than 30 min)	0.1	X	
	Expansive time (> 2 x nominal and > 30 min)	0.01		
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately Complex	2		
	Nominal	1	x	
		0.5		
	Obvious diagnosis	0.1		
	Insufficient information	1		
Experience/ Training	Low	10		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		
	Incomplete	20		
	Available, but poor	5		
	Nominal	1	X	
	Diagnostic/symptom oriented	0.5		
	Insufficient information	1		
Ergonomics/HI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	2		
	Nominal	1	X	
	Good	0.8		
	Insufficient information	1		
		NHEP =	**2.00E-03**	
	Negative PSFs adjustment (≥3 negative PSFs)		**NA**	
		Final Diagnosis HEP	**2.00E-03**	

B5a Operator Fails Action for Aligning Alternate DC Power

HRA Worksheets for LPSD

SPAR HUMAN ERROR WORKSHEET

Plant: ANO1 Initiating Event: Basic Event: DCP-XHE-XM-DD11D21
Basic Event Description: Operator Action to Align 125VDC Panel D11 to Feed 125VDC Panel D21

Part II. ACTION WORKSHEET

PSFs	PSF Levels	Multiplier for Action	Selected PSF	Please note specific reas for PSF level selection in this column.
Available Time	Inadequate time	P(failure) = 1.0		30 minutes required, aasumed 4 hour battery depletion time is t available.
	Time Available is ≈ the time required	10		
	Nominal time	1	X	
	Time available is ≥ 5x the time required	0.1		
	Time available is ≥ 50x the time required	0.01		
	Insufficient information	1		
Stress	Extreme	5		
	High	2	X	
	Nominal	1		
	Insufficient information	1		
Complexity	Highly	5		
	Moderately	2		
	Nominal	1	X	
	Insufficient information	1		
Experience/Training	Low	3		
	Nominal	1	X	
	High	0.5		
	Insufficient information	1		
Procedures	Not available	50		.
	Incomplete	20		
	Available but poor	5		
	Nominal	1	X	
	Insufficient information	1		
Ergonomics/HMI	Missing/Misleading	50		
	Poor	10		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
Fitness for Duty	Unfit	P(failure) = 1.0		
	Degraded Fitness	5		
	Nominal	1	X	
	Insufficient information	1		
Work Processes	Poor	5		
	Nominal	1	X	
	Good	0.5		
	Insufficient information	1		
		Final Action HEP	**2.00E-03**	

Appendix C: Cutsets

Top 40 Cutsets:

Top 20 Cutsets from Sequence 4

#	Prob/ Freq.	Total %	Cut Set	Description
Total	1.54E-5	100	Displaying 20 of 6784 Cut Sets.	
1	3.22E-6	20.9	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	9.63E-4		LPI-MOV-CC-CV1400	LPI DISCHARGE MOV CV-1400 FAILS TO OPEN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
2	3.18E-6	20.6	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
	9.51E-4		SWS-AOV-CC-CV3841	FAILURE OF SWS MOV CV-3841 TO PMP P34A TO OPEN
3	3.17E-6	20.5	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	9.47E-4		LPI-MDP-FS-P34B	LPI MDP P34B FAILS TO START
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
4	1.21E-6	7.84	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	3.62E-4		LPI-MDP-FR-P34B	LPI MDP P34B FAILS TO RUN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
5	1.04E-6	6.75	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
	2.48E-5		SWS-AOV-CF-CV38401	CCF OF SWS AOVs CV-3840/3841 TO PUMPS P34A/B TO OPEN
6	9.95E-7	6.44	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.37E-5		LPI-MDP-CF-STRT	LPI PUMP COMMON CAUSE FAILURES TO START
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
7	7.70E-7	4.99	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.83E-5		LPI-ACX-CF-VC1XR	Common Cause failure of DHR Unit Coolers VUC-1A,1B, 1C & 1D to RUN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
8	5.31E-7	3.44	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.26E-5		LPI-MDP-CF-RUN	LPI PUMP COMMON CAUSE FAILURES TO RUN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
9	3.18E-7	2.06	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	9.50E-5		LPI-ACX-CF-VC1CDR	Common Cause failure of DHR Unit Coolers VUC-1C and 1D to Run
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
10	1.22E-7	0.79	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-6		LPI-ACX-CF-VC1XS	Common Cause failure of DHR Unit Coolers VUC-1A,1B, 1C & 1D to Start

	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
11	1.17E-7	0.76	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	9.63E-4		LPI-MOV-CC-CV1400	LPI DISCHARGE MOV CV-1400 FAILS TO OPEN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
12	1.15E-7	0.75	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
	9.51E-4		SWS-AOV-CC-CV3841	FAILURE OF SWS MOV CV-3841 TO PMP P34A TO OPEN
13	1.15E-7	0.75	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	9.47E-4		LPI-MDP-FS-P34B	LPI MDP P34B FAILS TO START
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
14	1.00E-7	0.65	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.00E-7		SD-CUTOFF	HFE Cutoff Value for Shutdown
	1.00E+0		SD-XHE-XL-LOSDC-C	Operator Fails to Recover Loss of SDC/DHR before Boiling (cutoff)
	1.00E+0		SD-XHE-XL-LPR-C	Operator Fails to Initiate Low Pressure Recirc (cutoff)
15	9.68E-8	0.63	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A308	4160V AC BREAKER 152-308 FAILS TO CLOSE
	9.63E-4		LPI-MOV-CC-CV1400	LPI DISCHARGE MOV CV-1400 FAILS TO OPEN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
16	9.55E-8	0.62	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A308	4160V AC BREAKER 152-308 FAILS TO CLOSE
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
	9.51E-4		SWS-AOV-CC-CV3841	FAILURE OF SWS MOV CV-3841 TO PMP P34A TO OPEN
17	9.52E-8	0.62	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A308	4160V AC BREAKER 152-308 FAILS TO CLOSE
	9.47E-4		LPI-MDP-FS-P34B	LPI MDP P34B FAILS TO START
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
18	6.69E-8	0.43	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	2.00E-5		LPI-ACX-CF-VC1CDS	Common Cause failure of DHR Unit Coolers VUC-1C and 1D to Start
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
19	4.40E-8	0.28	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	3.62E-4		LPI-MDP-FR-P34B	LPI MDP P34B FAILS TO RUN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)
20	4.05E-8	0.26	M6-LOOP2 : 04	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.00E-3		EPS-XHE-XR-DG1	OP FAILS TO RESTORE DIESEL GENERATOR 1
	9.63E-4		LPI-MOV-CC-CV1400	LPI DISCHARGE MOV CV-1400 FAILS TO OPEN
	4.20E-2		LTREC-DHR-5D	Late Recovery of SDC/DHR (5 Days)

Top 20 Cutsets from Sequence 19

#	Prob/ Freq.	Total %	Cut Set	Description
Total	3.62E-4	100	Displaying 20 of 3955 Cut Sets.	
1	2.53E-4	70	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	7.96E-2		EPS-DGN-FR-DG2	DIESEL GENERATOR 2 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
2	4.33E-5	12	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.08E-3		EPS-DGN-CF-DG12R	CCF OF DIESEL GENERATORS DG1&DG2 TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
3	9.20E-6	2.54	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	2.89E-3		EPS-DGN-FS-DG2	DIESEL GENERATOR 2 FAILS TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
4	9.20E-6	2.54	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG2	DIESEL GENERATOR 2 FAILS TO RUN
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
5	7.61E-6	2.1	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A308	4160V AC BREAKER 152-308 FAILS TO CLOSE
	7.96E-2		EPS-DGN-FR-DG2	DIESEL GENERATOR 2 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
6	7.61E-6	2.1	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A408	4160V AC BREAKER 152-408 FAILS TO CLOSE
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
7	7.00E-6	1.94	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.20E-3		DCP-XHE-XM-DD11D21	Operator Action to Align 125VDC Panel D11 to Feed 125VDC Panel D21
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
8	4.31E-6	1.19	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
	9.93E-1		SWS-4C-RUNNING	SWS MDP P4C IS RUNNING; 4B ALIGNED TO RED TRAIN
	1.36E-3		SWS-MDP-FS-P4C	SERVICE WATER MDP P4C FAILS TO START
9	3.23E-6	0.89	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	8.09E-5		ACP-CRB-CF-A3A4-12	CCF OF A3-TO-A4 XTIE BREAKERS TO OPEN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
10	3.18E-6	0.88	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN

	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
	1.00E-3		EPS-XHE-XR-DG2	OP FAILS TO RESTORE DIESEL GENERATOR 2
11	3.18E-6	0.88	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG2	DIESEL GENERATOR 2 FAILS TO RUN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
	1.00E-3		EPS-XHE-XR-DG1	OP FAILS TO RESTORE DIESEL GENERATOR 1
12	3.07E-6	0.85	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG1	DIESEL GENERATOR 1 FAILS TO RUN
	9.63E-4		EPS-MOV-CC-CV3807	SWS SUPPLY MOV CV-3807 TO DGN 2 COOLING FAILS TO OPEN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
13	3.07E-6	0.85	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	7.96E-2		EPS-DGN-FR-DG2	DIESEL GENERATOR 2 FAILS TO RUN
	9.63E-4		EPS-MOV-CC-CV3806	SWS SUPPLY MOV CV-3806 TO DGN 1 COOLING FAILS TO OPEN
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
14	1.45E-6	0.4	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	3.61E-5		EPS-DGN-CF-DG12S	CCF OF DIESEL GENERATORS DG1&DG2 TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
15	9.47E-7	0.26	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.37E-5		EPS-MDP-CF-P16ABS	CCF of EDG Fuel Oil Pump to Start
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
16	7.43E-7	0.21	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.86E-5		EPS-MOV-CF-SWS	CCF OF SWS SUPPLY MOVs 3806 AND 3807
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
17	5.06E-7	0.14	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	1.26E-5		EPS-MDP-CF-P16ABR	CCF of EDG Fuel Oil Pump to Run
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
18	3.34E-7	0.09	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	2.89E-3		EPS-DGN-FS-DG2	DIESEL GENERATOR 2 FAILS TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
19	2.77E-7	0.08	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A308	4160V AC BREAKER 152-308 FAILS TO CLOSE
	2.89E-3		EPS-DGN-FS-DG2	DIESEL GENERATOR 2 FAILS TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days
20	2.77E-7	0.08	M6-LOOP2 : 19	
	1.00E+0		IE-M6-LOOP	LOOP Event Occurs during Mode 6
	2.39E-3		ACP-CRB-OO-1A408	4160V AC BREAKER 152-408 FAILS TO CLOSE
	2.89E-3		EPS-DGN-FS-DG1	DIESEL GENERATOR 1 FAILS TO START
	4.00E-2		EPS-XHE-XL-NR96H	OPERATOR FAILS TO RECOVER EMERGENCY DIESEL IN 4 Days

Unit 2
At-Power Detailed Risk Evaluation

Probabilistic Risk Assessment (PRA) Analyst:	David Loveless, Senior Risk Analyst
Independent Reviewer	Jeff Mitman, Senior Reliability and Risk Analyst, NRR/DRA/APOB

A. Summary of Issue:

At the time of the event, ANO Unit 2 was operating at 100 percent power.

At approximately 0750 hours on March 31, 2013, the temporary hoist assembly used to lift and transport the Unit 1 stator from the turbine building failed resulting in the ~524 ton stator dropping onto the Unit 1 turbine deck (Elev. 386’) and then rolling and falling onto the transport vehicle parked in the train bay (Elev. 354’).

The impact of the stator on the Unit 1 turbine deck resulted in substantial damage to turbine building structural members and to the turbine deck floor in the vicinity of the impact. The 4160 VAC switchgear A1 and A2 located immediately below where the stator impacted the turbine deck were damaged, rendering offsite power sources from startup #1 and startup #2 transformers inoperable.

Falling components impacted the north wall of the train bay causing structural damage and damage to the fire suppression system, causing substantial fire water spray into the train bay area. The stator came to rest against the south wall of the train bay on top of the transport vehicle. Both the north and south non-structural concrete masonry unit walls of the train bay suffered substantial damage.

The shock from the stator contacting the turbine building, and temporary lift assembly components falling into the turbine building, caused relays in the Unit 2 switchgear area located just adjacent to the train bay to actuate resulting in the trip of 2P-32B reactor coolant pump. This resulted in a trip to the Unit 2 reactor. The Unit 2 post-trip response was normal except it was complicated by Feedwater Loop A man feedwater regulating valve 2CV- 0748 position indication discrepancy. This caused the operators to trip the main feedwater pumps and manually initiated Emergency Feedwater.

The stator drop caused a rupture of an eight-inch fire main in the turbine building train bay. Water from the fire suppression system migrated to several areas of the turbine building on Unit 2. 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 non-safety-related switchgear in the turbine building. The loss of power from startup transformer 3 resulted in a loss of train B vital electrical bus (safety-related,) 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, restore the instrument air system and subsequently cooled Unit 2 to cold shutdown conditions on natural circulation.

B. Statement of the Performance Deficiency:

The licensee failed to accomplish actions specified in plant procedures. Procedure EN MA 119, “Material Handling Program” is a quality-related procedure that controls the licensee’s activities for handling and moving loads and rigging equipment at all Entergy sites. The procedure requires the licensee to review and approve the lifting rig design and verify that a load test is conducted. The licensee approved an inadequate design and did not conduct a load test.

C. Significance Determination Basis:

1. Reactor Inspection for IE, MS or BI Cornerstones

(a) Screening Logic

<u>Minor Question</u>: In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the finding was determined to be more than minor because it was associated with the procedural control attribute of the initiating event cornerstone, and adversely affected the cornerstone's objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The stator drop affected Unit 2 by causing a complicated reactor trip.

<u>Initial Characterization</u>: Using Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," the inspectors determined that the finding could be evaluated using the significance determination process. In accordance with Table 3, "SDP Appendix Router," the inspectors determined that the subject finding should be processed through Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 1, "Initiating Events Screening Questions," dated June 19, 2012.

<u>Issue Screening</u>: Using Appendix A, Exhibit 1, the inspectors determined that the finding did not affect loss of coolant accident initiators. The inspectors then determined that the finding did cause a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. This mitigation equipment, lost or degraded, included one source of offsite power, main feedwater, and the alternate ac diesel generator. Therefore, a detailed risk evaluation was required.

<u>Results</u>: The Region IV senior reactor analyst performed a detailed risk evaluation in accordance with Appendix A, Section 6.0, "Detailed Risk Evaluation." The detailed risk evaluation result is a preliminary finding of substantial safety significance (Yellow). The calculated change in core damage frequency of 2.8×10^{-5} was dominated by the internal event initiated by the stator drop on March 31, 2013. The analyst determined that the external event risk was negligible and that the finding would not involve a significant increase in the risk of a large, early release of radiation.

(b) <u>Detailed Risk Evaluation:</u>

(1) The Phase 3 model revision and other PRA Tools used
The analyst utilized the Standardized Plant Analysis Risk Model for Arkansas Nuclear One, Unit 2 (SPAR), Revision 8.21 and hand calculation methods to quantify the risk of the subject performance deficiency. The model was modified by the analyst and Idaho National Laboratories to include additional breakers and switching options, and to provide credit for recovery of emergency diesel generators during transient sequences. Additionally, the analyst performed additional runs of the SPAR model to account for consequential loss of offsite power risks that were not modeled directly under the special initiator.

(2) Influential assumptions

1. The subject performance deficiency directly resulted in the Unit 2 event on March 31, 2013. This event would not have occurred had the performance deficiency not existed. Therefore, the performance deficiency caused an increase in the nominal initiating event frequency of 1 over the assessment period.

2. Given Assumption 1, the exposure time was set to the 1-year assessment period. The actual exposure time that the performance deficiency existed is not critical.

3. The best available initiating event to model the subject performance deficiency is the loss of main feedwater initiator. The actual event was initiated by a general transient. However, a failure of the indication for Regulating Valve 2CV-748 prevented the main feedwater system from initiating a reactor trip override. As a result, operators tripped the operating main feedwater pump and initiated the emergency feedwater actuation system.

4. The analyst noted that the SPAR model does not model offsite power to a level sufficient to show failures within the offsite circuits. Therefore, the failure of Bus 2A2 is an appropriate surrogate for the Lockout of Startup Transformer 3. This surrogate was considered appropriate because Bus 2A2 was de-energized for approximately 44 hours following the event.

5. The alternate ac diesel generator was unavailable to respond at any point throughout its mission time because the stator drop caused significant damage to the control and power cabling associated with this generator.

6. The analyst noted that Version 8.21 of the SPAR model had not yet been updated to evaluate the risk of a postulated consequential loss of offsite power given a reactor trip. Based on NUREG/CR-6890, “Reevaluation of Station Blackout Risk at Nuclear Power Plants,” the conditional probability of a loss of offsite power given a reactor trip at a large nuclear power plant during times of higher grid loading is 3.91×10^{-3}/ trip. Multiple runs of the SPAR model can be made to quantify the change in risk for these postulated events.

(4) Calculation discussion

A detailed risk evaluation performed consistent with NRC Inspection Manual Chapter (IMC) 0609 Appendix A, Section 6.0, “Detailed Risk Evaluation.” To conduct a risk assessment and determine the change in core damage frequency (ΔCDF) an analyst must solve the following equation:

$$\Delta CDF = [(IEF_{case} * CCDP_{case}) - (IEF_{base} * CCDP_{base})] * EXP$$

Where:

- IEF_{case} ≡ Initiating Event Frequency of the case being evaluated
- $CCDP_{case}$ ≡ Conditional Core Damage Probability of the case
- IEF_{base} ≡ Initiating Event Frequency of the baseline
- $CCDP_{base}$ ≡ Conditional Core Damage Probability of the baseline
- EXP ≡ The Exposure Period including repair time

Conditional Core Damage Probability of the Event

The analyst used several surrogate basic events to model the event that occurred on March 31, 2013. First, the analyst modeled the event as a loss of main feedwater. The actual event was initiated by a transient. However, a failure of the indication for Regulating Valve 2CV-748 prevented the main feedwater system from initiating a reactor trip override. As a result, operators tripped the operating main feedwater pump and initiated the emergency feedwater actuation system. The analyst determined that a best estimate analysis would result from using the Loss of Main Feedwater initiator to model the risk of this event.

The analyst noted that the SPAR model does not model offsite power to a level sufficient to show failures within the offsite circuits. Therefore, the analyst used the failure of Bus 2A2 as a surrogate for the Lockout of Startup Transformer 3. This surrogate was considered appropriate because Bus 2A2 was de-energized for approximately 44 hours following the event.

As a final surrogate, the analyst modeled the gross failure of cabling associated with the AAC as an operator failure to start the machine. This surrogate provided the correct logic for the failure while indicating that the machine could not be recovered within the stated mission time.

The change set developed for the quantification of risk is documented in Table 1. The total change in core damage frequency calculated was 2.8×10^{-5}. This included additional runs performed to account for consequential loss of offsite power sequences not directly modeled in the current version of the SPAR.

Table 1 SPAR Change Set			
Basic Event	Event Description	Original Value	Modified Value
ACP-BAC-LP-2A2	Division B AC Power 4160V Bus 2A2 Fails	3.34E-05	True
ACP-CRB-OO-152113	Failure of CRB 152-113 to close	2.39E-03	True
EPS-XHE-XM-SBO	Operator Fails to Start SBO Diesel Generator	2.00E-02	True
IE-********	All Initiating Events	various	False
IE-LOMFW	Loss of Main Feedwater	6.89E-02	1.0

The above described SPAR model was evaluated using the SAPHIRE code Version 8.0.9.0. The truncation limit was set at 1E-12. The result of the model run was a conditional core damage probability of 2.74×10^{-5}.

The analyst noted that Version 8.21 of the SPAR model had not yet been updated to evaluate the risk of postulated consequential loss of offsite power given a reactor trip. Based on NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," the conditional probability of a loss of offsite power given a reactor trip at a large nuclear power plant during times of higher grid loading is 3.91×10^{-3}/ trip.

Using the same basic event modifications and truncation limit, the analyst set the loss of offsite power frequency to 3.91×10^{-3} and re-quantified the model. The result of the model run was a conditional core damage probability of 7.46×10^{-7}. Being mutually exclusive core damage sequences, the conditional core damage probabilities from the loss of offsite power and loss of main feedwater sequences can be summed. The analyst added the sequences to determine the total conditional core damage probability for the event of 2.8×10^{-5}.

Exposure Period

This SDP evaluation is an initiating event that occurred as a result of a performance deficiency. The calculation is a conditional core damage probability estimate and exposure time does not apply.

To show that the use of a conditional core damage probability estimate was appropriate, the analyst assumed that the exposure period started at March 31, 2013, when the stator was first lifted and ended on April 22, 2013, when the last of the major components affected were returned to service. This represented approximately 22 days of exposure and repair time. This exposure time corresponds to the time period that the condition being assessed was reasonably known to have existed plus the repair time (per the usage rules of IMC 0308, Attachment 3, Appendix A).

SPAR model basic event IE-LOMFW, representing a Loss of Main Feedwater initiator would then be set to a frequency corresponding to one event during the 22 days. The basis for the initiating event frequency change is that analyst noted, given the conditions of the temporary lift crane, the load would have always fallen at the time the load was rotated

to align with the truck bay. Therefore, the frequency of the loss of main feedwater, given a stator drop, was assumed to be 1.0 over the 22 day exposure time.

NOTE: This method of calculation is essentially equivalent to performing a conditional core damage probability assessment for a loss of main feedwater event and then subtracting the baseline core damage probability. Given that the core damage probability is approximately the integral of core damage frequency over time, at the point in time on March 31, 2013, where the initiating event occurred, this integral is equal to the conditional core damage probability multiplied by the integral of the Dirac delta function. This integral is the numerical equivalent to the conditional core damage probability.

Initiating Event Frequency

As discussed under "Exposure Period" above, the analyst determined that the best method to estimate the change in core damage frequency for the subject performance deficiency was by quantifying the conditional core damage probability for the event.

To continue the rough calculation of change in conditional core damage frequency the analyst increased the number of loss of main feedwater initiators by one over the exposure time (22-days). Therefore, the initiating event frequency was set as 4.55×10^{-2} /day.

Baseline Risk

As discussed under "Exposure Period" above, the analyst determined that the best method to estimate the change in core damage frequency for the subject performance deficiency was by quantifying the conditional core damage probability for the event.

However, for illustrative purposes, the analyst quantified the baseline loss of main feedwater conditional core damage probability. This value was 5.86×10^{-7}. The analyst noted that the SPAR model provides a baseline initiating event frequency for a loss of main feedwater at 6.89×10^{-2}/year.

Change in core damage frequency quantified

Given these calculations and assumptions, the analyst calculated the change in core damage frequency as follows:

$$
\begin{aligned}
\Delta CDF &= [(4.55 \times 10^{-2}/\text{day} \;*\; 2.8 \times 10^{-5}) \\
&\quad - (6.89 \times 10^{-2}/\text{year} \div 365 \text{ days/year} \;*\; 5.86 \times 10^{-7})] \;*\; 22 \text{ days} \\
&= [1.27 \times 10^{-6}/\text{day} - 1.11 \times 10^{-10}/\text{day}] \;*\; 22 \text{ days} \\
&= 2.79 \times 10^{-5}
\end{aligned}
$$

(5) Analysis of Dominant Cut-sets / Sequences
The dominant accident sequence cutsets involved a loss of main feedwater, loss of auxiliary feedwater, loss of emergency feedwater, and

the failure of once-through cooling. The evaluation of consequential loss of offsite power provided a dominant accident sequence involving a transient with consequential loss of offsite power, the loss of all feedwater to the steam generators and failure of once-through cooling.

Table 2
Core Damage Sequences

Sequence	Description	Point Estimate	% of Total	Cut Set Count
MFW-14	IEMFW-FW-OTC	2.69E-5	95.6	6,036
LOOP-19	IELOOP-EFW-OTC	3.79E-7	1.3	1,733
LOOP-20-09-10	IELOOP-SBO(EPS)-RSUB-OPR08H-DGR08H-EFWMAN-SGDEPLT	2.74E-7	1.0	527
MFW-15-10	IEMFW-RPS-FWATWS	1.25E-7	0.4	157
MFW-13	IEMFW-FW-SSRC-HPR	8.98E-8	0.3	1,679
LOOP-20-30	IELOOP-SBO-EFW-OPR08H-DGR08H	8.00E-8	0.3	959
MFW-02-09-04	IEMFW-LOSC-RCPT-HPI	6.14E-8	0.2	814
MFW-15-11	IEMFW-RPS-RCSPRESSURE	3.99E-8	0.1	18
MFW-15-09	IEMFW-RPS-BORATION	3.79E-8	0.1	16
MFW-12	IEMFW-FW-SSCR-CSR	2.63E-8	0.1	560
Others	All Additional Sequences Combined	1.33E-7	0.5	3,886
Total CCDP	All Sequences	2.81e-5	100.0	16,385

Abbreviations

BORATION	Failure of Emergency Boration
CBO	Controlled Bleedoff Isolated
CSR	Containment Spray Recirculation
DGR08H	Nonrecovery of Diesel Generator in 8 Hours
EFW	Emergency Feedwater
EFWMAN	Manual Control of Emergency Feedwater
EPS	Emergency Power System
FW	Feedwater System (MFW, EFW, and auxiliary feedwater)
FWATWS	Feedwater System under ATWS Conditions
HPI	High Pressure Injection
HPR	High Pressure Recirculation
IELOOP	Initiating Event: Loss of Offsite Power
IEMFW	Initiating Event: Loss of Main Feedwater
LOSC	Loss of RCP Seal Cooling
OPR08H	Nonrecovery of Offsite Power in 8 Hours
OTC	Once-Through Cooling
RCPT	Reactor Coolant Pumps Tripped
RCSPRESS	RCS Pressure Limited
RSUB	Reactor Coolant Subcooling Maintained
RPS	Reactor Protection System
SBO	Station Blackout
SGDEPLT	Late Depressurization of Steam Generators
SSCR	Secondary Cooling Recovered

The dominant accident sequence cutsets involved a loss of main feedwater, loss of auxiliary feedwater, loss of emergency feedwater, and the failure of once-through cooling. The top ten sequence cutsets are provided in Table 2 of the detailed risk evaluation. The top 100 cutsets

for each of two model runs are provided as attachments to this evaluation.

The results are dominated by one core damage sequence. The largest contributor is Sequence 14 from the loss of main feedwater tree. The sequence comprises a failure of all feedwater to the steam generators, including main feedwater, auxiliary feedwater, and emergency feedwater, with a loss of once-through cooling. The remainder of the sequences are dominated by failure of the emergency diesel generators without recovery of ac power.

(6) Sensitivity Analysis

The SRA performed a variety of uncertainty and sensitivity analyses on the internal events model as shown below. The results confirm the recommended Yellow finding.

Sensitivity Analysis 1 – Transient without Loss of Main Feedwater.

The SRA ran the model using a transient as the initiator. The change in core damage frequency was 1.10×10^{-5} (Yellow).

Sensitivity Analysis 2 – No consequential loss of offsite power.

The SRA ran the model without including the additional runs to calculate the change in risk from a postulated consequential loss of offsite power. The change in core damage frequency was 2.74×10^{-5} (Yellow).

Sensitivity Analysis 3 – Potential Recovery of Bus 2A2

The SRA ran the model with the failure of Bus 2A2 probability set to 6.79×10^{-1}. This value, calculated using SPAR-H methodology, represented the probability that operators would fail to recover the bus prior to core damage, given the adverse and unknown conditions of site electrical supply. The change in core damage frequency was 1.97×10^{-5} (Yellow).

(7) Contributions from External Events (Fire, Flooding, and Seismic)

Manual Chapter 0609, Appendix A, Section 6.0 requires, “when the internal events detailed risk evaluation results are greater than or equal to 1.0E-7, the finding should be evaluated for external event risk contribution.” The analyst noted that this detailed risk assessment evaluates an actual event in which no external events occurred. Additionally, the period of time that the events impacted plant equipment was small enough that the probability of an external initiator occurring during this time would be negligible. Therefore, the analyst assumed that the risk from external events, given the subject performance deficiency was essentially zero.

(8) Potential Risk Contribution from LERF

In accordance with the guidance in NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," this finding would not involve a significant increase in risk of a large, early release of radiation because Arkansas Nuclear One, Unit 2 has a large, dry containment and the dominant sequences contributing to the change in the core damage frequency did not involve either a steam generator tube rupture or an inter-system loss of coolant accident.

(9) Total Estimated Change in Core Damage Frequency

The total change in risk caused by this performance deficiency is the sum of the internal and external events change in core damage frequencies. This value was 2.8×10^{-5} (YELLOW).

(10) Licensee's Risk Evaluation

The licensee provided an assessment of the risk related to the March 31, 2013 event. With similar modeling assumptions, the licensee's at-power probabilistic safety assessment provided a conditional core damage probability of 2.94×10^{-5}/year. This corroborated the NRC analyst's evaluation. However, the licensee calculated per component repair times for the major components affected by the performance deficiency and stated that the change in core damage frequency, after removing qualitative modeling "conservatisms" was less than 1×10^{-6}, resulting in a Green finding.

Using the licensee's method, the exposure period defined by the licensee affected the time following the plant transient. However, the licensee did not adjust the initiating event likelihood to address the increased rate of failure over this new exposure time.

(11) Summary of Results and Impact

The NRC's quantitative risk assessment was determined to represent a risk estimate in the "Yellow" region. Region IV recommends a preliminary finding of substantial safety significance (Yellow based on change in core damage frequency).

(d) <u>Peer Review:</u>

Jeff Mitman, Senior Reliability and Risk Analyst, NRR/DRA/APOB

(e) <u>References:</u>

The analysts used the following generic references in preparing the risk assessment:

- NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants"

- NUREG/CR-6883, “The SPAR-H Human Analysis Method.” August 2005
- NUREG-1842, “Good Practices for Implementing Human Reliability Analysis.” April 2005
- NUREG/CR-6595 Revision 1, “An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events.” October 2004
- INL/EXT-10-18533 Revision 2, “SPAR-H Step-by-Step Guidance.” May 2011
- “RASP Manual Volume 1 – Internal Events,” Revision 2.0 date January 2013
- Risk Assessment of Operational Events, Volume 2 – “External Events,” Revision 1.01, January 2008
- NUREG/CR-1278, “Handbook of HRA with Emphasis on Nuclear Power Plant Applications,” August 1983
- NRC Inspection Manual Chapter 0609, “Significance Determination Process”

The analysts used the following plant specific references:

- Standardized Plant Analysis Risk (SPAR) model for Arkansas Unit 2, Version 8.21
- Arkansas Nuclear One, Unit 2, Final Safety Analysis Report Page 8.3-12
- EOP: 1202.007, Degraded Power
- AOPs:
    - 1203.024, Loss of Instrument Air
    - 1203.028, Loss of Decay Heat Removal
    - 1203.050, Unit 1 Spent Fuel Pool Emergencies
- Calculation: 89-E-0017-01, Time to Boiling and Time to Core Uncovery after Loss of Decay Heat Removal, Unit 1, Revision 7
- Procedure: 1103.018, Maintenance of RCS Water Level