UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 7, 2005

Jeffrey S. Forbes, Vice President,
Operations
Arkansas Nuclear One
Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas 72801-0967

SUBJECT: ARKANSAS NUCLEAR ONE - NRC INTEGRATED INSPECTION REPORT 05000313/2005004 AND 05000368/2005004

Dear Mr. Forbes:

On September 23, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Arkansas Nuclear One, Units 1 and 2, facility. The enclosed integrated report documents the inspection findings, which were discussed on September 28, 2005, with you and other members of your staff.

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

The report documents five inspector identified and self-revealing findings of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements; however, because the findings were entered into your corrective action program, the NRC is treating these violations as noncited violations consistent with Section VI.A of the Enforcement Policy. Additionally, a licensee identified violation which was determined to be of very low safety significance is listed in this report. If you contest these noncited 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, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Arkansas Nuclear One, Units 1 and 2, facility.

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

Sincerely,

**/RA/**

David N. Graves, Chief
Project Branch E
Division of Reactor Projects

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

Enclosure:
NRC Inspection Report 05000313/2005004 and 05000368/2005004
w/Attachment: Supplemental Information and Phase 3 Evaluation, Damaged Reactor Coolant Pump Seal, Arkansas Nuclear One, Unit 2

cc w/enclosure:
Senior Vice President
& Chief Operating Officer
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

Vice President
Operations Support
Entergy Operations, Inc.
P.O. Box 31995
Jackson, MS 39286-1995

Manager, Washington Nuclear Operations
ABB Combustion Engineering Nuclear
Power
12300 Twinbrook Parkway, Suite 330
Rockville, MD 20852

County Judge of Pope County
Pope County Courthouse
100 West Main Street
Russellville, AR 72801

Winston & Strawn LLP
1700 K Street, N.W.
Washington, DC 20006-3817

Bernard Bevill
Radiation Control Team Leader
Division of Radiation Control and
Emergency Management
Arkansas Department of Health
4815 West Markham Street, Mail Slot 30
Little Rock, AR 72205-3867

James Mallay
Director, Regulatory Affairs
Framatome ANP
3815 Old Forest Road
Lynchburg, VA 24501

Technological Services Branch
Chief
FEMA Region VI
800 North Loop 288
Federal Regional Center
Denton, Texas 76201-3698

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(RJC1)**
Senior Resident Inspector **(RWD)**
Branch Chief, DRP/E **(DNG)**
Senior Project Engineer, DRP/E **(VGG)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**
Regional State Liaison Officer **(WAM)**
NRR/DIPM/EPB/EPHP **(REK)**
DRS STA **(DAP)**
J. Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
**ROPreports**
ANO Site Secretary **(VLH)**

SISP Review Completed: DNG ADAMS: / Yes ☐ No Initials: _DNG_____
/ Publicly Available ☐ Non-Publicly Available ☐ Sensitive / Non-Sensitive

R:_ANO\2005\AN2005-04RP-RWD.wpd

| RIV:RI:DRP/E | RI:DRP/E | SRI:DRP/E | C:DRS/PSB |
|---|---|---|---|
| JLDixon | ELCrowe | RWDeese | MPShannon |
| VGGaddy for | VGGaddy for | VGGaddy for | /RA/ |
| 11/02/05 | 11/02/05 | 11/02/05 | 10/31/05 |

| C:DRS/OB | C:DRS/EMB | C:DRS/PEB | C:DRP/E |
|---|---|---|---|
| TGody | CJPaulk | LJSmith | DNGraves |
| /RA/ | /RA/ | /RA/ | /RA/ |
| 11/01/05 | 11/01/05 | 11/02/05 | 11/07/05 |

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

**U.S. NUCLEAR REGULATORY COMMISSION**
**REGION IV**

| | |
|---|---|
| Dockets: | 50-313, 50-368 |
| Licenses: | DPR-51, NPF-6 |
| Report: | 05000313/2005004 and 05000368/2005004 |
| Licensee: | Entergy Operations, Inc. |
| Facility: | Arkansas Nuclear One, Units 1 and 2 |
| Location: | Junction of Hwy. 64W and Hwy. 333 South<br>Russellville, Arkansas |
| Dates: | June 24 through September 23, 2005 |
| Inspectors: | K. Clayton, Operations Engineer<br>E. Crowe, Resident Inspector<br>R. Deese, Senior Resident Inspector<br>J. Dixon, Resident Inspector<br>P. Elkmann, Emergency Preparedness Inspector<br>P. Goldberg, Reactor Inspector<br>W. McNeill, Reactor Inspector<br>M. Murphy, Senior Operations Engineer |
| Approved By: | David N. Graves, Chief, Project Branch E<br>Division of Reactor Projects |

Enclosure

## CONTENTS


SUMMARY OF FINDINGS . . . -1-
1R01 Adverse Weather Protection . . . -1-
1R04 Equipment Alignment . . . -2-
1R05 Fire Protection . . . -2-
1R06 Flood Protection Measures . . . -4-
1RO7 Heat Sink Performance . . . -5-
1R11 Licensed Operator Requalification Program . . . -6-
1R12 Maintenance Effectiveness . . . -7-
1R13 Maintenance Risk Assessments and Emergent Work Control . . . -8-
1R14 Operator Performance During Nonroutine Plant Evolutions and Events . . . -11-
1R15 Operability Evaluations . . . -14-
1R16 Operator Workarounds . . . -14-
1R17 Permanent Plant Modifications . . . -15-
1R19 Postmaintenance Testing . . . -15-
1R22 Surveillance Testing . . . -16-
1R23 Temporary Plant Modifications . . . -17-
1EP2 Alert Notification System Testing . . . -18-
1EP3 Emergency Response Organization Augmentation Testing (71114.03) . . . -18-
1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies . . . -19-
1EP6 Drill Evaluation . . . -19-
4OA1 Performance Indicator Verification . . . -20-
4OA2 Problem Identification and Resolution . . . -21-
4OA3 Event Followup . . . -24-
4OA4 Crosscutting Aspects of Findings . . . -24-
4OA5 Other Activities . . . -25-
4OA6 Meetings, Including Exit . . . -26-
4OA7 Licensee-Identified Violations . . . -26-

ATTACHMENT 1: . . . A-1
KEY POINTS OF CONTACT . . . A-1
LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED . . . A-2
LIST OF DOCUMENTS REVIEWED . . . A-3
LIST OF ACRONYMS . . . A-12

ATTACHMENT 2: PHASE 3 EVALUATION, DAMAGED REACTOR COOLANT PUMP SEAL ARKANSAS NUCLEAR ONE, UNIT 2 . . . A2-1

## SUMMARY OF FINDINGS

IR 05000313/2005004, 05000368/2005004; 6/24/05 - 9/23/05; Arkansas Nuclear One, Units 1 and 2; Maintenance Risk Assessments, Operator Performance During Nonroutine Plant Evolutions and Events, Problem Identification and Resolution, Other Activities.

This report covered a 3-month period of inspection by resident inspectors and regional specialist inspectors. Five Green findings, three of which were noncited violations. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors reviewed a self-revealing finding for an inadequate troubleshooting procedure for the Unit 2 pressurizer level instrumentation. When implemented, the procedure resulted in the unplanned energizing of all pressurizer heaters with Unit 2 operating at normal operating pressure and a subsequent increase in reactor coolant system pressure which was not anticipated by operators. The licensee entered the procedural failure to address the effect of de-energizing Alarm Relay Bistable 2LC-4627-1BN on the pressurizer heater circuitry into their corrective action program for resolution. The cause of the finding is related to the crosscutting element of human performance.

  This finding is greater than minor because it affected the procedure quality attribute under the initiating events cornerstone objective of limiting the likelihood of those events that upset plant stability. Using the significance determination process, the finding was determined to have very low safety significance because this transient initiator did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available (Section 1R14.1).

- Green. The inspectors reviewed a self-revealing finding for an inadequate maintenance procedure which resulted in Control Element Assembly 50 dropping into the core with Unit 2 operating at 100 percent rated thermal power. During troubleshooting efforts for a missing phase on the upper gripper for Control Element Assembly 56, power to the only gripper holding Control Element Assembly 50 fully withdrawn (the lower gripper) was removed by instrumentation and control technicians. The procedure failed to contain detailed guidance to ensure that Control Element Assembly 50 was properly being held by the upper gripper. The licensee performed a thorough root cause of the event to determine the short and long term corrective actions. The cause of the finding is related to the crosscutting element of human performance.

This finding is greater than minor because it affected the procedure quality attribute under the initiating events cornerstone objective of limiting those events that upset plant stability. Using the significance determination process, the finding was determined to have very low safety significance because this transient initiator did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available (Section 1R14).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of 10 CFR 50.65(a)(4) for the failure to perform an adequate risk assessment before replacement activities associated with Unit 1 decay heat room Cooler VUC-1D. Because the work procedure referenced an outdated engineering report, it did not include adequate information to ensure that the required risk management actions were taken. Mechanical maintenance personnel failed to inform operations personnel that a Unit 1 decay heat vault door was open and incapable of being readily shut. The licensee entered this performance deficiency into their corrective action program for resolution. The cause of the finding is related to the crosscutting element of human performance.

  This finding is more than minor because it affected the attribute under the mitigating systems cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences, in that the licensee failed to implement compensatory risk management measures. Using the maintenance risk assessment and risk management significance determination process, the finding was determined to have very low safety significance because the performance deficiency was associated only with inadequate risk management actions and the incremental increase in core damage probability was negligible (Section 1R13).

- Green. The inspectors identified a noncited violation of 10 CFR 50.65(a)(4) for the failure to perform an adequate risk assessment before the isolation of the Unit 1 electromatic relief valve. Operators considered that there would be no impact on plant risk before isolating the electromatic relief valve, but they failed to consider the increased probability of a pressurizer code safety valve failing to reseat. The licensee entered this performance deficiency into their corrective action program for resolution. The cause of the finding is related to the crosscutting element of human performance.

  This finding is greater than minor because it related to a risk assessment which failed to consider a risk significant component that was unavailable during maintenance and contained known errors that had the potential to change the outcome of the assessment. Using the Maintenance Risk Assessment and Risk

Management Significance determination process, the finding was determined to have very low safety significance because the inadequate risk assessment only had an incremental increase in core damage probability of less than $1 \times 10^{-6}$ (Section 1R13).

- Green. The inspectors reviewed a self-revealing noncited violation of Unit 2 Technical Specification 6.4.1, "Procedures," when reactor coolant pump seal injection flow was established with the reactor coolant pump uncoupled from its motor. This activity led to damage of the seal for Reactor Coolant Pump 2P-32C. This damage required conducting an additional reduced reactor coolant system inventory maintenance period to replace the seal. The licensee performed a thorough root cause of the event to determine the short and long term corrective actions. The cause of the finding is related to the crosscutting element of human performance.

  This finding is greater than minor because it affected the procedural quality attribute under the mitigating systems cornerstone objective of ensuring the availability and reliability of the reactor coolant system inventory, such that the licensee had to enter a higher risk plant operating state to repair the seal. Using the shutdown operations significance determination process, the inspectors determined the finding required a Phase 2 analysis. In the Phase 2 analysis, risk analysts determined the finding to be of very low safety significance because (1) the seal replacement activity only required establishing reduced inventory conditions (not midloop) and (2) the time needed to replace the seal was not extensive (Section 4OA5).

Cornerstone: Barrier Integrity

B. Licensee-Identified Violations

Violations of very low safety significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and their corrective actions are listed in Section 4OA7 of this report.

# REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power and remained there throughout the inspection period.

Unit 2 began the inspection period at 100 percent rated thermal power and remained there until September 8, 2005, when the unit down powered to approximately 65 percent rated thermal power as a result of a dropped control element assembly (CEA). The unit subsequently returned to 100 percent rated thermal power on September 10, 2005, and remain there for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

Readiness for Seasonal Susceptibilities. The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving extreme high temperatures. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the systems listed below to ensure that adverse weather protection features were sufficient to support operability including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee would maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- August 10, 2005, Unit 1 high pressure injection (HPI) and emergency feedwater (EFW) systems

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial System Walkdowns. The inspectors: (1) walked down portions of the three risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned and (2) compared deficiencies identified during the walkdown to the licensee's CAP to ensure problems were being identified and corrected.

- August 4, 2005, Unit 1 HPI system
- August 10, 2005, Unit 1 EFW system
- August 22-23, 2005, Unit 1 safety-related DC electrical system

The inspectors completed three samples.

Complete Walkdown. The inspectors: (1) reviewed plant procedures, drawings, the Updated Safety Analysis Report, Technical Specifications, and vendor manuals to determine the correct alignment of the system; (2) reviewed outstanding design issues, operator work arounds, and CAP documents to determine if open issues affected the functionality of the system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

- July 27-29, 2005, Unit 2 containment spray system

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Routine Inspection. The inspectors walked down the seven plant areas listed below to assess the material condition of active and passive fire protection features, their operational lineup, and their operational effectiveness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the CAP to determine if the licensee identified and corrected fire protection problems.

- June 30, 2005, Unit 1 Fire Zone 38-Y, EFW pump room
- July 12, 2005, Unit 1 Fire Zone 97-R, integrated control system (ICS) relay room and cable spreading room
- July 15, 2005, Unit 2 Fire Zone 2101-AA, north switchgear room
- July 19, 2005, Unit 2 Fire Zone 2096-M, motor control center room
- July 29, 2005, Unit 1 Fire Zone Area N, intake structure
- July 29, 2005, Unit 1 Fire Zone 112-I, lower north electrical penetration room
- August 31, 2005, Unit 1 Fire Zone 98-J, emergency diesel generator corridor

b. Findings

Unit 1 EFW Pump Room Sprinklers

The inspectors identified an unresolved item (URI) for the Unit 1 EFW pump room fire sprinklers. On June 30, 2005, the inspectors reviewed the licensee's commitment for train separation in Fire Zone 38-Y, Unit 1 EFW pump room. The inspectors learned that since the licensee could not demonstrate train separation per 10 CFR Part 50, Appendix R, Section III.G.2, for the as-built configuration, the licensee requested an exemption from Appendix R in 1988. The exemption was required because the turbine-driven and motor-driven EFW pumps and cables share a common room and have as little as 4 feet of electrical separation. One of the requirements from the granted exemption was that a fire sprinkler system be built and designed per National Fire Protection Association (NFPA) 15, 1985 Edition, around the turbine-driven EFW pump. NFPA 15, defined a water spray system as a normally open sprinkler head. However, upon inspection of Fire Zone 38-Y, the EFW pump room, the inspectors noticed that the licensee's installed sprinkler system had frangible bulb sprinkler heads installed. The inspectors then reviewed the licensee's design change package that installed the sprinkler system and discovered it stated that the system was designed and installed using the guidelines of NFPA 13 and 15, 1985 Edition. The licensee could not provide to the inspectors supporting documentation to show that the installed sprinkler system met NFPA 15, 1985 Edition, or that a deviation to the NFPA code was established due to the sprinkler heads being frangible bulb type. The licensee contracted an NFPA code expert to determine the status of the installed sprinkler system with regard to the requirements of NFPA 15, 1985 Edition, and is awaiting the completion of the report. In response to this issue, the licensee established alternate suppression and hourly fire watch compensatory measures ensuring an on-going safety concern did not exist. The licensee entered this condition into their CAP as Condition Report (CR) ANO-1-2005-0954. Pending completion and review of the licensee's code compliance document and a review of the safety significance by the regional senior reactor analyst, this finding is considered unresolved (URI 05000313/2005004-01, "Failure to Comply with Licensing Basis for Emergency Feedwater Pump Room Fire Sprinklers.")

Unit 1 ICS Relay Room Sprinklers

On July 12, 2005, in preparation for inspection of the ICS relay room, the inspectors referenced the applicable section of "Arkansas Nuclear One - Units 1 and 2 Fire Hazards Analysis," Revision 9. The inspectors determined from this review that the ICS relay room was contained within Fire Zone 97-R which was to be protected by an automatic deluge suppression system. The inspectors then conducted their walkdown and noted that no sprinkler systems were in the ICS relay room. The inspectors questioned licensee fire protection engineers who could not readily explain the discrepancy and, subsequently, generated CR ANO-1-2005-1158 to explore the discrepancy. Because the corrective action to explain this discrepancy was still incomplete, the inspectors identified this condition as a URI 05000313/2005004-02, "Absence of ICS Relay Room Fire Sprinklers."

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

Annual External Flooding. For the building listed below, the inspectors: (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of: (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the areas listed below to verify the adequacy of (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

C August 29, 2005, Unit 2 auxiliary building

The inspectors completed one sample.

Semiannual Internal Flooding. For the area listed below, the inspectors: (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps; (b) level alarm circuits; (c) cable splices subject to submergence; and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the areas listed below to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals; (c) watertight door seals; (d) common drain lines and sumps; (e) sump pumps, level alarms, and control circuits; and (f) temporary or removable flood barriers.

C July 27-29, 2005, Unit 2 Train B high pressure safety injection (HPSI), low pressure safety injection, and containment spray pump room and gallery

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1RO7 Heat Sink Performance (71111.07)

a. Inspection Scope

Biennial Inspection. The inspectors reviewed design documents (e.g., calculations and performance specifications), program documents, implementing documents (e.g., test and maintenance procedures), and corrective action documents. The inspectors discussed various corrective action items, heat exchanger testing and cleaning, and design verification with licensee personnel.

For heat exchangers directly connected to the safety-related service water system, the inspectors verified whether thermal performance testing, or heat exchanger inspection, maintenance and cleaning, and the chemistry monitoring program provided sufficient controls to ensure proper heat transfer. Specifically, the inspectors reviewed: (1) heat exchanger test methods and test results from performance testing, (2) heat exchanger inspection and cleaning methods and results, (3) chemical water treatment and results, and (4) verification of design including flow balancing to ensure sufficient heat exchanger flow.

For heat exchangers directly or indirectly connected to the safety-related service water system, the inspectors verified the: (1) condition and operation were consistent with design assumptions in the heat transfer calculations, (2) potential for water hammer, as applicable, (3) chemistry controls for heat exchangers indirectly connected to the safety-related service water system, and (4) redundant and infrequently used heat exchangers are flow tested periodically to ensure sufficient flow.

If available, the inspectors reviewed additional nondestructive examination results for the selected heat exchangers that demonstrated structural integrity.

The inspectors selected heat exchangers that ranked high in the plant specific risk assessment and were directly or indirectly connected to the safety-related service water system. The inspectors selected the following heat exchangers:

- Unit 1 shutdown cooling heat exchanger
- Unit 1 reactor building coolers
- Unit 2 engineered safety feature room coolers

The inspectors selected and completed three heat exchanger samples, which meets the inspection procedure requirement of two to three samples.

The inspectors verified that the licensee had entered significant heat exchanger/heat sink problems into the CAP. The inspectors reviewed 11 corrective action documents.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

Quarterly Inspection. On August 9, 2005, the inspectors observed testing and training of Unit 1 senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. Training Scenario A1SPGLOR060101, "New OTSGs," Revision 0, was used and involved a main steam line break inside containment concurrent with an EFW malfunction which led to overcooling of the reactor coolant system. The main steam line break was modeled using the once-through SGs which are scheduled for installation in the upcoming refueling outage.

The inspectors completed one sample.

Biennial Inspection for Unit 1 and Annual Inspection for Unit 2. The inspectors: (1) evaluated examination security measures and procedures for compliance with 10 CFR 55.49; (2) evaluated the licensee's sample plan of the written examinations for compliance with 10 CFR 55.59 and NUREG-1021, "Operator Licensing Examiner Standards," as referenced in the facility requalification program procedures; and (3) evaluated maintenance of license conditions for compliance with 10 CFR 55.53 by review of facility records (medical and administrative), procedures, and tracking systems for licensed operator training, qualification, and watchstanding. In addition, the inspectors reviewed remedial training for examination failures for compliance with facility procedures and responsiveness to address failed areas.

Furthermore, the inspectors: (1) interviewed six personnel (two operators, two instructors, the training supervisor, and one evaluator) regarding the policies and practices for administering examinations, (2) observed the administration of two dynamic simulator scenarios to one requalification crew; and (3) observed four evaluators administer six job performance measures, four in the control room simulator in a dynamic mode and two in the plant under simulated conditions.

The inspectors also reviewed the remediation process and the results of the biennial written examination. The results of the examinations were assessed to determine the licensee’s appraisal of operator performance and the feedback of performance analysis to the requalification training program. The inspectors interviewed members of the training department and operating crews to assess the responsiveness of the licensed operator requalification program. The inspectors also observed the examination security maintenance for the operating tests during the examination week.

Additionally, the inspectors assessed the Arkansas Nuclear One, Unit 1, plant-referenced simulator for compliance with 10 CFR 55.46 using Inspection Procedure 71111.11 (Section 03.11). This assessment included the adequacy of the licensee’s simulation facility for use in operator licensing examinations and for satisfying experience requirements as prescribed by 10 CFR 55.46. The inspectors reviewed a sample of simulator performance test records (transient tests, surveillance tests, malfunction tests, and scenario-based tests), simulator discrepancy report records, and processes for ensuring simulator fidelity commensurate with 10 CFR 55.46. The inspectors also interviewed members of the licensee’s simulator configuration control group as part of this review.

In addition to the biennial review for Unit 1, the inspectors reviewed the test results of the Unit 2 annual operating examination for 2005. Since this was the first half of the biennial requalification testing cycle, the licensee had not yet administered the written examination. These results were assessed to determine if they were consistent with NUREG-1021 guidance and Manual Chapter (MC) 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," requirements. This review included examination test results for 56 licensed individuals.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the two maintenance activities listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and Technical Specifications.

- September 21, 2005, Units 1 and 2 control room emergency ventilation system inoperabilities

- September 23, 2005, Unit 2 HPSI pump performance

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

Risk Assessment and Management of Risk. The inspectors reviewed the assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) that the licensee identified and corrected problems related to maintenance risk assessments.

- June 13-16, 2005, Unit 2 steam bypass Valve 2CV-0306 and planned maintenance during the week

- June 23, 2005, Unit 1 decay heat room Cooler VUC-1D replacement and planned maintenance during the week

- August 1-5, 2005, Unit 1 HPI Pump P-36A overhaul and planned maintenance during the week

- July 6 through September 23, 2005, Units 1 and 2 preparations inside the protected area for the Unit 1 replacement outage

The inspectors completed four samples.

Emergent Work Control. The inspectors: (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; (3) reviewed the CAP to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- July 8, 2005, Unit 1 condenser vacuum Pump C-5A inoperability

- August 25, 2005, Unit 1 isolation of the pressurizer electromatic relief valve (ERV)

The inspectors completed two samples.

b. Findings

Unit 1 Decay Heat Room Cooler Maintenance

Introduction. The inspectors identified a Green noncited violation (NCV) of 10 CFR 50.65(a)(4) for the failure to perform an adequate risk assessment before the replacement of Unit 1 decay heat room Cooler VUC-1D.

Description. On June 23, 2005, during the decay heat room Cooler VUC-1D replacement activities, the licensee opened the Green Train decay heat vault door, Door 5, to allow for the old cooler to be rigged out of the room. The inspectors noted that Door 5 was a high energy line break (HELB), fire, and flooding door and then questioned operators about the status of the equipment in the room and what risk management actions were being performed as a result of Door 5 being blocked open. Operations personnel were not aware that the door was blocked open. The inspectors learned that Maintenance personnel had failed to ensure that Operations personnel had been informed that they opened Door 5 to remove the old room cooler.

Upon further review, the licensee discovered that the work order package for the job was outdated and incomplete. The work order package was initially written in 2001 and referenced an engineering request (ER) which had been superceded since the time the work order package was written. As a result, the operational impact concerns were out of date and the appropriate notification points to inform and/or request permission from operations was not included. The superceded ER that was referenced only addressed the door from a HELB perspective. Had the licensee's up-to-date ER been referenced, fire and flooding concerns, in addition to HELB concerns, would have been addressed. The inspectors concluded that as a result of using an outdated work order and a superceded ER, operations did not ensure that the required risk management actions were taken, specifically, controls to ensure the establishment of a firewatch and ensuring that flood mitigation hatches remained closed.

Analysis. The inspectors determined that the failure to ensure proper risk management actions were taken was a performance deficiency. This finding is greater than minor because it affected the availability objective of the equipment performance attribute under the mitigating systems cornerstone, in that, the finding related to the licensee failing to implement and effectively manage compensatory measures. Using Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process," of MC 0609, "Significance Determination Process," the finding was determined to have very low safety significance (Green) because the performance deficiency was associated only with inadequate risk management actions and the incremental increase in core damage probability was negligible (less than $1 \times 10^{-6}$). This issue had human performance crosscutting aspects associated with having an inadequate work package and maintenance personnel not communicating with operations personnel which resulted in risk management actions not being implemented.

Enforcement. 10 CFR 50.65(a)(4) requires, in part, that the licensee shall assess and manage the increase in risk that may result from proposed maintenance activities. Contrary to this, on June 23, 2005, the licensee did not adequately assess risk from maintenance activities that resulted in a HELB, fire, and flooding door being open and incapable of being readily shut. Because of the very low safety significance and because the licensee included this condition in the CAP as CR ANO-C-2005-1205, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000313/2005004-03, "Failure to Adequately Assess Risk for a Blocked Decay Heat Vault Door."

Unit 1 ERV Isolation

Introduction. The inspectors identified a Green NCV of 10 CFR 50.65(a)(4) for the failure to perform an adequate risk assessment associated with the manual isolation of the Unit 1 ERV.

Description. On August 25, 2005, Unit 1 operators noticed that the acoustic monitor indication for the Unit 1 pressurizer ERV was not operable. Operators decided to isolate the ERV by shutting its isolation Valve CV-1000 since the ERV was considered to be inoperable with its acoustic monitoring indication out of service. Discussions among operations personnel concluded that the licensee's risk management assessment program modeled both opened and closed failure modes. They reasoned that since the ERV was isolated, it could not fail to reseat and that failure mode should not be accounted for in a risk assessment. The operators also reasoned that, since the valve was inoperable because of an indication issue, the valve was available and that failure mode should not be accounted for in the risk assessment model either. As a result, the operators assumed no impact on risk would be made when isolating the ERV.

The inspectors reviewed the licensee's assessment for the existing plant conditions and concluded that the licensee had correctly used their risk management program to assess the risk with the ongoing maintenance with HPI Pump P-36A, low pressure injection Valve CV-1429, and Inverter Y-25. The inspectors then discovered in the licensee’s risk assessment program that fault trees existed which showed that with the ERV isolated, the pressurizer code safety valves would be the method of preventing reactor coolant system overpressure since they would open first on any fast breaking pressure increase transient. Additionally, the inspectors learned that the probability that the pressurizer code safety valves would not close after lifting would be increased since their probability of opening increased. From this the inspectors concluded that the licensee’s risk assessment was incomplete since it did not incorporate the added risk from the increased likelihood that a pressurizer code safety valve would stick open.

Analysis. The inspectors considered that the failure to account for the risk of an isolated ERV was a performance deficiency. The inspectors determined this finding was greater than minor because it related to a licensee's risk assessment which had known errors that had the potential to change the outcome of the assessment. Using Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process," of MC 0609, "Significance Determination Process," the finding was determined to have very low safety significance (Green) because the incremental increase in core damage probability was less than $2.24 \times 10^{-8}$. In this determination, the inspectors assumed Inverter Y-25 and HPI Pump P-36A were already out of service for maintenance when the ERV was isolated. Also, the inspectors used 8 hours (between 6:59 a.m. and 3:04 p.m. on August 25, 2005) as the time of the inaccurate risk assessment, which was the time when both the ERV was isolated and Green Train of the low pressure injection system was removed from service. This issue had human performance crosscutting aspects associated with operations personnel incorrectly assuming a component had no risk significance which resulted in a non-conservative risk assessment.

Enforcement. 10 CFR 50.65(a)(4) requires, in part, that the licensee shall assess and manage the increase in risk that may result from proposed maintenance activities. Contrary to this, the licensee did not adequately assess risk from isolating the Unit 1 pressurizer ERV. Because of the very low safety significance and because the licensee included this condition in the CAP as CR ANO-C-2005-1257, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000313/2005004-04, "Failure to Adequately Assess Risk for an Isolated Pressurizer Electromatic Relief Valve."

1R14 Operator Performance During Nonroutine Plant Evolutions and Events (71111.14 and 71153)

a. Inspection Scope

The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts for the evolutions listed below to evaluate operator performance in coping with nonroutine events and transients; (2) verified that the operator response was in accordance with the response required by plant procedures and training; and (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- April 24, 2005, Unit 1 loss of auxiliary cooling water flow
- June 16, 2005, Unit 2 inadvertent energization of all pressurizer heaters
- August 7, 2005, Unit 1 nuclear instrumentation power excursion to 101.87 percent nuclear instrument power
- September 8, 2005, Unit 2 dropped Controlled Element Assembly 50

The inspectors completed four samples.

b. Findings

.1 Inadvertent Energization of All Unit 2 Pressurizer Heaters

Introduction. The inspectors reviewed a Green self-revealing finding involving the unplanned energization of all Unit 2 pressurizer heaters caused by an inadequately researched maintenance procedure.

Description. On June 1, 2005, the licensee was troubleshooting spiking in the Unit 2 pressurizer level indication using a preplanned work procedure. While in the process of replacing Alarm Relay Bistable 2LC-4627-1BN in the indication circuitry, instrumentation and control (I&C) technicians lifted electrical Lead 7 per the work procedure. Lifting this lead caused a daisy chain of power losses which caused power to be lost to Relay 63X/LC-110H in the pressurizer heater circuitry. This action in turn energized all of the backup heaters and shunted the output of the pressurizer heater hand controller station, thereby, fully energizing all proportional heaters. Lifting of Lead 7 also caused the Channel 1 high pressurizer level alarm annunciator to alarm unexpectedly. With all pressurizer heaters energized, reactor coolant system pressure rose to approximately 15 psig above normal operating pressure. In the diagnosis of the high pressurizer level annunciator, operators recognized that all pressurizer heaters were energized, took manual control, and restored pressure to normal. Additionally, I&C technicians re-landed Lead 7. During inspection of this occurrence, the inspectors discovered that the scope of the work package was inadequate, because lifting the lead had not been properly researched by system engineers or work planners causing the unexpected plant response.

Analysis. The inspectors determined that the licensee's failure to adequately research the effects of their maintenance on the pressurizer level circuitry was a performance deficiency. This finding is greater than minor because it affected the human performance attribute under the initiating events cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. Using the Phase 1 worksheets in MC 0609, "Significance Determination Process," the issue was determined to have very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. This finding had crosscutting aspects of human performance, in that, the engineers and planners did not adequately research a procedure prior to its use on the plant.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on nonsafety-related plant equipment. Licensee personnel entered this issue into the CAP as CR ANO-2-2005-1678. This issue is being treated as a finding: FIN 05000368/2005004-05, "Failure to Adequately Scope the Effects of Maintenance on Pressurizer Level Instrumentation."

.2 Dropped Unit 2 CEA

Introduction. The inspectors reviewed a self-revealing Green finding for an inadequate maintenance procedure and troubleshooting plan which resulted in a dropped CEA on Unit 2.

Description. On September 8, 2005, during troubleshooting efforts for CEA 56, CEA 50 dropped to the bottom of the core. At the time of the event, Subgroup 13, which contain CEAs 50 and 56, was being transferred to the hold bus to allow for replacement of the opto-isolator card for CEA 56. Control Element Assembly 56 troubleshooting indicated that a phase on the upper gripper was firing all the time. The troubleshooting plan that was being used allowed for I&C maintenance personnel to transfer the rods to the hold bus by ‘skill of the craft.’ However, if operations personnel were to perform the same task, they had specific guidance contained in Operating Procedure 2105.009, "CEDM Control System Operation," Revision 21. As a result of not having detailed guidance in the troubleshooting plan, not using the operations procedure as a reference and not having familiarity from performing transfers to the hold bus on frequent bases, I&C maintenance personnel failed to ensure that CEA 50 was latched by the upper gripper. When I&C transferred Subgroup 13 to the hold bus, the automatic CEA timer module detected a voltage imbalance on CEA 50 and transferred CEA 50 to the lower gripper. Subsequently, when the contact for the normal supply to CEA 50 was opened, power to the lower gripper was removed resulting in CEA 50 dropping to the bottom of the core.

Analysis. The inspectors considered that the failure to provide adequate procedural guidance for CEA transfers to I&C technicians was a performance deficiency. This finding is greater than minor because it affected the procedure quality attribute under the initiating events cornerstone objective of limiting those events that upset plant stability. Using the Phase 1 worksheets in MC 0609, "Significance Determination Process," the finding was determined to have very low safety significance (Green) because this transient initiator does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. This issue had human performance crosscutting aspects associated with an inadequate maintenance procedure.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on nonsafety-related equipment. The licensee included this condition in the CAP as CR ANO-2-2005-2191. This issue is being treated as a finding: FIN 05000368/2005004-06, "Inadequate Maintenance Procedure Results in Dropped CEA."

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

For the four operability evaluations listed below, the inspectors: (1) reviewed plants status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- CR-ANO-1-2005-0954, July 1, 2005, Unit 1 EFW water spray system

- CR-ANO-1-2005-1022, July 15, 2005, Unit 1 HELB Door 62, electrical equipment room

- CR-ANO-C-2005-1472, August 2, 2005, Units 1 and 2 molded case circuit breakers in safety-related 480 volt switchgear

- CR-ANO-C-2005-1538, August 11, 2005, Units 1 and 2 emergency cooling pond fish eradication impact on service water systems

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed the two operator workarounds listed below to: (1) determine if the functional capability of the system or human reliability in responding to an initiating event is affected, (2) evaluate the effect of the operator workaround on the operator's ability to implement abnormal or emergency operating procedures, and (3) verify that the licensee has identified and implemented appropriate corrective actions associated with operator workarounds.

- August 9, 2005, Units 1 and 2 ground on Unit 1 Red Train 125V dc bus isolated to fuses which resulted in the loss of both units control room indications for switchyard breakers

- August 19, 2005, Unit 2 Operator Work Around 2-05-07 safety injection Tank 2T-2C losing inventory excessively

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

Annual Review

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flowpaths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the modification listed below. The inspectors verified that: (1) modification preparation, staging, and implementation does not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) postmodification testing will maintain the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, SSC performance characteristics still meet the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria has been met; and (3) the licensee has identified and implemented appropriate corrective actions associated with permanent plant modifications.

- August 12, 2005, Unit 1 reactor vessel closure head replacement per ER-ANO-2002-0638-000

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the six postmaintenance test activities of risk significant systems or components listed below. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the CAP to determine if the licensee identified and corrected problems related to postmaintenance testing.

- March 21, 2005, Unit 2 HPSI Pump 2P-89C, troubleshooting to determine source of increased vibration levels
- June 21, 2005, Unit 1 HPI Pump P-36B inboard motor bearing oiler unqualified for application
- August 16, 2005, Unit 2 excore Channel B power supply switch replacement
- August 18, 2005, Units 1 and 2 control room ventilation Valve SV-7910, outside air makeup damper for control room ventilation Fan VSF-9, replacement
- August 19, 2005, Unit 1 instrument air Compressor C-28A air end replacement
- August 31, 2005, Unit 2 service water Valve 2CV-1519 stroke failure

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

For the five surveillances listed below, the inspectors reviewed the Updated Safety Analysis Report, procedure requirements, and Technical Specifications to ensure they demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- January 1 through July 31, 2005, Unit 2 emergency cooling pond level detection
- July 13, 2005, Unit 2 HPSI header check Valve 2SI-12
- July 14, 2005, Unit 1 control room emergency ventilation system inlet Damper CV-7910
- August 2, 2005, Unit 2 containment air monitoring system Instrument 2RITS-8231-1A (Leakage Detection System)
- August 25, 2005, Unit 1 low pressure injection Pump P-34B (Inservice Test)

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

For the three temporary modifications listed below, the inspectors reviewed the Updated Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the temporary modifications were properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability, (2) verified that the installation was consistent with the modification documents, (3) ensured that the postinstallation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test, (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings, and (5) verified that appropriate safety evaluations were completed. The inspectors verified that the licensee identified and implemented any needed corrective actions associated with temporary modifications.

- July 21, 2005, Unit 1 control room emergency ventilation system inlet Damper CV-7910
- July 28, 2005, Unit 2 pressurizer level instrumentation
- August 30 through September 1, 2005, Unit 1 makeup Pump P-36A temporary wall removal

The inspectors completed three samples.

b. Findings

No findings of significance was identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspector discussed with the licensee and staff from the Arkansas Department of Health the status of offsite siren and tone alert radio systems to determine the adequacy of methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The Arkansas Department of Health's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, Federal Emergency Management Agency (FEMA) Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," and the current FEMA-approved alert and notification system design report. The inspector also reviewed the following procedures:

- "Procedures for Testing, Verification, and Maintenance of the Emergency Warning System," Arkansas Department of Health, May 2004, Revision 0
- Desk Guide EP-002, "Early Warning System," Revision 10

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspector reviewed results from two emergency response staffing drills and reviewed the following documents related to the emergency response organization augmentation system to determine the licensee's ability to staff emergency response facilities in accordance with the licensee emergency plan and the requirements of 10 CFR Part 50, Appendix E.

- Procedure 1903.062, "Communication System Operating Procedure," Revision 18
- Form 1903.062C, "Emergency Response Staffing Drill," Revision 18

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspector reviewed the following documents related to the licensee's CAP to determine the licensee's ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E.

- EN-LI-102, "Corrective Action Process," Revision 1
- Emergency Preparedness CR Threshold Criteria, Revision 0
- Seven quarterly department assessments
- Three Entergy peer group assessments
- LO-ALO-2003-234, "Alert Notification System Assessment," December 8, 2003
- LO-ALO-2005-033, "Emergency Preparedness Department Program Assessment," April 2005
- Five evaluation reports for full scale drills
- Two evaluation reports for emergency preparedness drills
- NQ 2004-0026, "Quality Assurance Audit Report QA-7-2004-ANO-1, Emergency Planning," June 8, 2004
- 02C-ANO-2003-0055, Quality Assurance Observation
- Summaries of 176 corrective actions assigned to the emergency preparedness department between July 1, 2003, and June 1, 2005

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The two drills listed below contributed to drill/exercise performance and emergency response organization (ERO) performance indicators. The inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, document's acceptance criteria.

- July 20, 2005, emergency response organization drill involving a station blackout initiated from the Unit 2 simulator and activating the Technical Support Center, Emergency Operations Facility, and Operations Support Center

- July 27, 2005, emergency response organization drill involving a station blackout initiated from the Unit 2 simulator and activating the Technical Support Center, Emergency Operations Facility, and Operations Support Center

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspector sampled the licensee's performance indicator submittals listed below for the period October 1, 2004, through March 31, 2005. The definitions and guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period. Licensee performance indicator data were also reviewed against the requirements of Procedures EN-LI-114, "Performance Indicator Process," Revision 0; EN-EP-201, "Emergency Planning Performance Indicators," Revision 1; and EPJA-EOF-21, "Emergency Preparedness Performance Indicators," Revision 0.

Emergency Preparedness Cornerstone:

- Drill and exercise performance
- Emergency response organization participation
- Alert and notification system reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios, licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspector reviewed licensee emergency response rosters and drill participation records. The inspector reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspector also interviewed licensee personnel responsible for collecting and evaluating performance indicator data.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

.1 Emergency Preparedness Annual Sample Review

a. Inspection Scope

The inspector selected 30 CRs for detailed review. The reports were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspector evaluated the CRs against the requirements of Procedure EN-LI-102, "Corrective Action Process," Revision 1.

b. Findings

No findings of significance were identified.

.2 Daily Reviews

a. Inspection Scope

The inspectors performed a daily review of all condition reports entered into the licensee corrective action program during this inspection period to identify repetitive failures and human performance issues. These daily reviews also assessed licensee identification of issues at the appropriate threshold and entry of these issues into their corrective action program.

4OA3 Event Followup (71153)

(Closed) Licensee Event Report (LER) 05000368/2002001-00, Reactor Coolant System Pressure Boundary Leakage Due To Primary Water Stress Corrosion Cracking of Pressurizer Heater Sleeves

During the Unit 2 refueling outage in April and May 2002, the licensee discovered that the reactor coolant system had leaked through six pressurizer heater sleeves. The inspectors previously reviewed these leaks and documented the review in NRC Inspection Report 05000313/2004002; 05000368/2004002, but this LER was not closed pending the characterization of the metallurgical flaws which caused these leaks. The inspectors discovered that the licensee does not intend to characterize the flaws on the

Unit 2 pressurizer because the existing flaws have been repaired and because they have planned to replace the pressurizer in Fall 2006. Additionally, the inspectors reviewed a similar event in NRC Inspection Report 0500313/2005003; 0500368/2005003 (Section 4OA3.2) in which LER 0500368/2005001-00 was closed for the same issue, leaking pressurizer heater sleeves. For further information of this previously dispositioned violation, see NRC Inspection Report 0500313/2004002; 00500368/2004002 (Section 4OA3.2) NCV 050036/2004-002, "Ineffective Corrective Actions to Prevent Recurrence of Primary Water Stress-Corrosion Cracking of Alloy 600 Material." As a result, the inspectors foresee no needed future inspection of this LER. This LER is closed.

4OA4 Crosscutting Aspects of Findings

Cross-Reference to Human Performance Findings Documented Elsewhere

Section 1R13 describes a condition where maintenance personnel failed to communicate to Unit 1 operations the status of Door 5, which resulted in operations not being able to ensure that the required controls were exercised. This same finding also documents an inadequate work package in that the correct ERs were not listed, which resulted in risk management actions not being implemented.

Section 1R13 describes a finding where operations personnel incorrectly assumed isolation of the Unit 1 ERV would have no impact on plant risk, which resulted in an inadequate risk assessment.

Section 1R14 describes a condition where engineers and work planners did not adequately research a troubleshooting procedure which resulted in energization of all Unit 2 pressurizer heaters.

Section 1R14 describes a condition where an inadequate maintenance procedure resulted in a Unit 2 CEA falling into the core. The procedure lacked the necessary guidance because the task of transferring control element assemblies to the hold bus was viewed as ‘skill of the craft’ even though such evolutions are infrequently performed.

4OA5 Other Activities

.1 Followup to Operational Readiness of Offsite Power (Temporary Instruction (TI) 2515/163)

The inspectors conducted followup inspection to TI 2515/163, "Operational Readiness of Offsite Power," to determine the extent of the licensees written guidance on various aspects of the TI. The results were forwarded to the Division of Engineering in the Office of Nuclear Reactor Regulation for further review.

.2 (Closed) Apparent Violation 05000368/2005003-01, Inadequate Procedure Leads To Reactor Coolant Pump Seal Damage

Introduction. The inspectors completed the significance determination of the apparent violation documented in NRC Inspection Report 05000313/2005003 and 05000368/2005003. The apparent violation involved an inadequate procedure related to the alignment of reactor coolant pump (RCP) seal injection flow when the pump and motor were uncoupled. An additional entry into reduced reactor coolant system (RCS) inventory conditions during the refueling outage was necessary to repair the damaged RCP seal caused by this performance deficiency.

Analysis. The inspectors considered that the failure to have an adequate procedure for ensuring isolation of seal injection when a Unit 2 reactor coolant pump was uncoupled was a performance deficiency. Traditional enforcement does not apply for this finding because it did not have any actual safety consequences or potential for impacting the NRC's ability to perform its regulatory function nor was it the result of any willful violation of NRC requirements. The inspectors determined that this finding is greater than minor because it was associated with the Mitigating Systems Cornerstone configuration control attribute and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors used Appendix G, "Shutdown Operations Significance Determination Process," of MC 0609, "Significance Determination Process," to further determine the significance of this finding.

Unplanned entry into reduced RCS inventory conditions to repair the RCP seal represented additional risk incurred above the planned outage risk. The additional risk associated with the reduced RCS inventory evolution constitutes the additional risk incurred above the planned outage risk. A Phase 1 screening of the finding was performed using Appendix G and the Attachment 1 checklists. The finding was not considered a "Loss of Control" using Table 1. Using Checklist 3, "PWR Cold Shutdown and Refueling Operation - RCS Open and Refueling Cavity Level < 23' Or RCS Closed and No Inventory in Pressurizer, Time to Boiling < 2 hours," in Attachment 1, "Phase 1 Operational Checklists for both PWRs and BWRs," of Appendix G of MC 0609, the inspectors determined this finding required quantitative assessment because the finding increased the likelihood of a loss of RCS inventory by requiring an additional entry into a reduced RCS inventory condition. Therefore, the finding was referred to the regional senior reactor analyst for further evaluation.

Since the finding did not involve low temperature overpressure protection, nozzle dams, or boron dilution, the analyst used Appendix G, Attachment 2, "Phase 2 SDP Template for PWR During Shutdown." The finding involved an additional entry into a high-risk Plant Operating State (POS). Therefore, as cautioned in Attachment 2, the senior reactor analyst consulted with staff in the Office of Nuclear Reactor Regulation to evaluate the change in core damage frequency associated with the finding. The following is a summary of the analysis that was performed.

After review of Appendix G and its associated technical basis document MC 0308, Attachment 3, Appendix G, the analysts concluded that the applicable initiators for this condition were the loss of offsite power (LOOP), loss of residual heat removal (LORHR), and loss of inventory (LOI). The analysts considered loss of level control (LOLC) as a potential initiator, but rejected it because the LOLC worksheet was only applicable to midloop RCS conditions and the performance deficiency resulted in an additional drain only to RCP seal replacement elevation. The analysts concluded that solution of each of the applicable initiator worksheets at their "base case" value was an appropriate conservative estimation of the increase in risk due to the finding.

The additional entry into reduced inventory conditions occurred approximately 28 days after shutdown for the refueling outage and lasted approximately 30 hours (< 3 days). These conditions correlate to the Late Time Window (TW-L) of POS 2 in the SDP and were used to solve each of the following initiators:

**LOOP**

Worksheet 4, "Loss of Offsite Power in POS 2 (RCS Vented)," was evaluated. The initiating event likelihood (IEL) for the LOOP initiator for exposure less than 3 days is 3. The analyst reviewed the top event functions, equipment success criteria, and important instrumentation identified in Worksheet 4 to determine appropriate equipment credits to evaluate the core damage sequences. Top event function EAC was assigned a credit of 4, accounting for the emergency and alternate a.c. diesel generators. The analysts assumed that operator credit was similar to equipment credit for this top event and made no reduction for operator error. Gravity feed to the RCS was not credited. Recovery of offsite power was assigned a credit of 1. Quantification of the sequences by summing the IEL and mitigation credits for each top event function resulted in the most limiting sequence having a result of 8.

**LORHR**

Worksheet 9, "Loss of RHR in POS 2 (RCS Vented)," was evaluated. The IEL for the LORHR initiator for exposure less than 3 days is 3. The analyst reviewed the top event functions, equipment success criteria, and important instrumentation identified in Worksheet 9 to determine appropriate equipment credits to evaluate the core damage sequences. Top event function RHR-S was assigned a credit of 1, which credited operator ability to start a decay heat removal train prior to RCS boiling. Top event FEED was assigned a credit of 4 accounting for the multi-train safety injection system and positive displacement charging pumps. Operator credit was also 4 for this top event, so no reduction was applied. Top event RHR-R was assigned a credit of 2, consistent with the worksheet for being operator-action limited. Top event RWSTMU was also assigned a credit of 2, consistent with the worksheet for being operator-action limited. Quantification of the sequences by summing the IEL and mitigation credits for each top event function resulted in the most limiting sequence having a result of 8.

**LOI**

Worksheet 6, "Loss of Inventory in POS 2 (RCS Vented)," was evaluated. The IEL for the LOI initiator for exposure less than 3 days is 4. The analyst reviewed the top event functions, equipment success criteria, and important instrumentation identified in Worksheet 6 to determine appropriate equipment credits to evaluate the core damage sequences. Top event function FEED was assigned a credit of 4 accounting for the multi-train safety injection system and positive displacement charging pumps. Operator credit was also 4 for this top event, so no reduction was applied. Top event LEAK-STOP was assigned a credit of 3, limited by operator action. Top event RHR-R was assigned a credit of 3, consistent with the worksheet for being operator-action limited. Top event RWSTMU was assigned a credit of 2, consistent with the worksheet for being operator-action limited. Quantification of the sequences by summing the IEL and mitigation credits for each top event function resulted in the most limiting sequence having a result of 8.

**Result**

The risk significance of the finding from this point is determined in the same manner as for at-power findings. Using MC 0609, Appendix A, Step 2.4, "Estimating the Risk Significance of Inspection Findings," the analyst summed the quantified sequences and determined that the total increase in core damage frequency associated with this finding due to internal initiating events was estimated as 1E-7/year using the counting rule. No screening for potential contribution due to external events or large early release frequency was performed because of the assumed conservative upper-bound screening result provided by the SDP worksheets. Therefore, this was a finding of very low safety significance (Green). Contributing to this result was that (1) the seal replacement activity required RCS draindown to reduced inventory conditions and not to midloop conditions, (2) the time needed to replace the seal was not extensive and, (3) the time after shutdown provided additional time available for successful operator actions.

Enforcement. The inspectors determined that since Procedure 2103.002, "Filling and Venting the Reactor Coolant System," Revision 39, was inadequate, it did not meet the requirements of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, and as a result the licensee did not meet Unit 2 Technical Specification 6.4.1, "Procedures." Because of the very low safety significance of this finding and because the licensee included this condition in their CAP as CR ANO-2-2005-0545, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000368/2005004-07, "Inadequate Procedure Leads To Reactor Coolant Pump Seal Damage."

4OA6 Meetings, Including Exit

On July 1, 2005, the inspector presented the emergency planning inspection results to Mr. J. Forbes, Vice President, Operations, and other members of the licensee's staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

The inspectors debriefed the licensee's operator requalification inspection results with Ms. S. Cotton, Training Manager, and other members of the licensee’s staff at the conclusion of the inspection on July 15, 2005. The licensee acknowledged the findings presented. A telephone exit was held with Mr. R. Martin, Unit 1 Operations Training Supervisor, acting for Ms. S. Cotton, on August 17, 2005. He was advised that the inspectors had completed reviewing the results of the annual requalification test results for Unit 2 and the biennial requalification test results for Unit 1. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

The inspectors presented the inspection results to Mr. J. Forbes, Vice President, Operations, and other members of the licensee's staff at the conclusion of the heat sink performance biennial inspection on September 12, 2005, during a telephonic exit. No proprietary information was reviewed.

The resident inspectors presented the inspection results of the resident inspections to Mr. J. Forbes, Vice President, Operations, and other members of the licensee's management staff on September 28, 2005. The licensee acknowledged the findings presented. The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee-Identified Violations

The following two examples of a violation of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of NUREG-1600, "NRC Enforcement Policy," for being dispositioned as NCV.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established for the selection and review of materials, parts, equipment, and processes that are essential to safety-related functions. The licensee violated this requirement on two occasions. The first example, which occurred on March 21, 2005, during the Unit 2 HPSI Pump 2P-89C disassembly troubleshooting, to determine the source of increased vibration levels, the licensee discovered that a carbon steel set screw had been installed in place of a stainless one required by design specifications. This event is documented in the licensee’s CAP as CR ANO-2-2005-0775. This finding is of very low safety significance because the safety-related function of the HPSI system was never lost. The second example, which occurred on June 21, 2005, during the Unit 1 HPI Pump P-36B gearbox rebuild, the licensee installed an unqualified bearing oiler on the inboard motor bearing which

caused increased vibrations of the oiler. This event is documented in the licensee's CAP as CR ANO-1-2005-0884. This finding is of very low safety significance because the safety-related function of the HPI system was never lost.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee Personnel

R. Barnes, Manager, Planning and Scheduling
S. Bennett, Project Manager, Licensing
B. Berryman, Manager, Unit 1 Operations
E. Blackard, Supervisor, Mechanical Design Engineering
J. Browning, Manager, Unit 2 Operations
R. Byford, Training Supervisor/Operations Training
A. Clinkingbeard, U-1 Operations Training Assistant Operations Manager
S. Cotton, Manager, Training
S. Cupp, Simulator Support Supervisor
J. Eichenberger, Manager, Corrective Actions and Assessments
J. Forbes, Vice President, Operations
N. Finney, Technical Specialist IV, Non-Destructive Examination
M. Ginsberg, Supervisor, Design Engineering
A. Hawkins, Licensing Specialist
J. Hoffpauir, Manager, Maintenance
R. Holeyfield, Manager, Emergency Planning
I. Jacobson, System Engineer
D. James, Acting Director, Nuclear Safety Assurance
W. James, Manager, Alloy 600 Group
J. Johnson, Fire Protection Technical Specialist
J. Kowalewski, Director, Engineering
R. Kowalewski, Manager, Technical Support
D. Lomax, Manager, Dry Fuels
R. Martin, U-1 Operations Training Supervisor
T. Mayfield, U-2 Operations Training Supervisor
J. Miller, Manager, Systems Engineering
T. Mitchell, Acting General Manager, Plant Operations
D. Moore, Manager, Radiation Protection
K. Nichols, Manager, Design Engineering
R. Puckett, Fire Protection Supervisor
S. Pyle, Licensing Specialist
C. Reasoner, Manager, Engineering Programs and Components
R. Scheide, Licensing Specialist
J. Sigle, U-2 Acting Operations Manager
C. Tyrone, Manager, Quality Assurance
F. Van Buskirk, Licensing Specialist/ANO Licensing
B. Williams, Director, Reactor Vessel Head/SG Replacement Project

Arkansas Department of Health

C. Meyer, Nuclear Planning and Response Program Manager

NRC

R. Kahler, NSIR/DPR/EPD, Team Leader

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000313/2005004-01 | URI | Failure to Comply with Licensing Basis for EFW Pump Room Fire Sprinklers (Section 1R05) |
| 05000313/2005004-02 | URI | Absence of ICS Relay Room Fire Sprinklers (Section 1R05) |

Opened and Closed

| | | |
|---|---|---|
| 05000313/2005004-03 | NCV | Failure to Adequately Assess Risk for a Blocked Decay Heat Vault Door (Section 1R13) |
| 05000313/2005004-04 | NCV | Failure to Adequately Assess Risk for an Isolated Pressurizer ERV (Section 1R13) |
| 05000368/2005004-05 | FIN | Failure to Adequately Scope the Effects of Maintenance on Pressurizer Level Instrumentation (Section 1R14) |
| 05000368/2005004-06 | FIN | Inadequate Maintenance Procedure Results in Dropped CEA (Section 1R14) |
| 05000368/2005004-07 | NCV | Inadequate Procedure Leads to Reactor Coolant Pump Seal Damage (Section 4OA5) |

Closed

| | | |
|---|---|---|
| 05000368/2002-001-00 | LER | Reactor Coolant System Pressure Boundary Leakage Due to Primary Water Stress Corrosion Cracking of Pressurizer Heater Sleeves (Section 4OA3) |
| 05000368/2005003-01 | AV | Inadequate Procedure Leads to Reactor Coolant Pump Seal Damage (Section 4OA5) |

Discussed

None

## LIST OF DOCUMENTS REVIEWED

In addition to the documents referred to in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R04: Equipment Alignment

CRs

| | | |
|---|---|---|
| ANO-2-2004-0620 | ANO-2-2004-1704 | ANO-2-2005-1193 |
| ANO-2-2004-0702 | ANO-2-2004-2054 | ANO-2-2005-1424 |
| ANO-2-2004-0837 | ANO-2-2004-2055 | ANO-2-2005-1921 |
| ANO-2-2004-0922 | ANO-2-2004-2091 | ANO-2-2005-1927 |
| ANO-2-2004-0936 | ANO-2-2005-0387 | |

Operating Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| 2104.005 | Containment Spray | 43 |

Miscellaneous

| NUMBER | TITLE | |
|---|---|---|
| ULD-2-SYS-05 | Arkansas Nuclear One Upper Level Document ANO Unit 2 Containment Spray System | 3 |

Section 1R05: Fire Protection

CRs

| | |
|---|---|
| ANO-1-2005-0954 | ANO-1-2005-1197 |

Engineering Calculation

85-E-0053-15, Revision 45

Miscellaneous Documents

| NUMBER | TITLE | REVISION |
|---|---|---|
| DCP 87-D-1051 | EFW Pump Room Fire Suppression System | 0 |
| Engineering Report A-FP-2005-001 | Fire Protection Appendix R Detection & Suppression Partial 86-10 Evaluation | 0 |
| NFPA 15 | Standard for Water Spray Fixed Systems for Fire Protection | 1985 Edition |

| | | |
|---|---|---|
| NFPA 15 | Standard for Water Spray Fixed Systems for Fire Protection | 2001 Edition |
| NRC Information Notice 2002-24 | Potential Problems with Heat Collectors on Fire Protection, Sprinklers | July 19, 2002 |
| 0CAN088404 | Results of Reanalysis Against NRC Clarification/Interpretation of Appendix R to 10 CFR Part 50 | August 15, 1984 |
| 0CAN088508 | Results of Reanalysis Against NRC Clarification/Interpretation of Appendix R to 10 CFR Part 50 - Supplemental Information | August 30, 1985 |
| 1CAN048708 | 10 CFR Part 50 Appendix R Exemption Request (Zone 38-Y) | April 22, 1987 |
| 1CAN068706 | 10 CFR Part 50 Appendix R Exemption Request (Zone 38-Y) | June 24, 1987 |
| 1CNA108806 | Exemptions from the Technical Requirements of Appendix R to 10 CFR Part 50 - Arkansas Nuclear One, Unit 1 (TAC NO. 55669) | October 26, 1988 |

Operating Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| | Arkansas Nuclear One Fire Hazards Analysis Report | 9 |
| | Unit 1 Prefire Plans 1A-372-100-N | 2 |
| 1000.152 | Unit 1 & 2 Fire Protection System Specifications | 3 |
| 1203.002 | Alternate Shutdown | 15 |
| 1203.049 | Fires in Areas Affecting Safe Shutdown | 2 |

Plant Drawings

| NUMBER | TITLE | REVISION |
|---|---|---|
| FP-103 | Fire Zones Intermediate Floor Plan at Elev. 368' - 0" and 372' - 0" | 24, Sheet 1 |
| FP-105 | Fire Zone Plan Below Grade Elev. 335' - 0" | 18, Sheet 1 |
| FP-110 | Fire Zones Intake Structure | 10, Sheet 1 |
| FP-2103 | Fire Zones Intermediate Floor Plan Elev. 368' - 0" | 26, Sheet 1 |

Section 1R06: Flooding

Engineering Report

92-R-0024-01

Section 1R07: Heat Sink Performance

Operating Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| 2311.002 | Service Water System Flow Test | 14 |
| EN-LI-102 | Corrective Action Process | 2 |
| | Unit 1 and Unit 2 Service Water and Circulating Water Optimization Plan | 1 |

Specifications

ANO FSAR Unit 2, Section 6.3.4, "Tests and Inspections"

ERs

| NUMBER | TITLE | REVISION |
|---|---|---|
| ANO-2004-0294-000 | Decay Heat Cooler Thermal Test Evaluation | 0 |
| ANO-2005-0287-000 | 2R17 As Left Test Evaluation | 0 |
| 991457-E205-0 | Service Water Flow Testing | 0 |
| ANO-2004-0294-000 | 1R18 E-35A Decay Heat Cooler Thermal Test Evaluation | 0 |

CRs

| | | |
|---|---|---|
| ANO-1-2004-0831 | ANO-2-1999-0254 | ANO-2-1999-0535 |
| ANO-2-1999-0211 | ANO-2-1999-0580 | ANO-2-1999-0559 |
| ANO-2-1999-0219 | | |

Calculations

| NUMBER | TITLE | REVISION |
|---|---|---|
| 88-E-0098-16 | Revised Containment Cooler Data for ANO | 001 |
| 94-E-0095-18 | Room 2007/2009 Heat Load Evaluation | 0 |
| 88-E-0098-20 | Heat Load Evaluation | 0 |
| 88-E-0098-20 | ANO-1 DBA Analysis | 1 |

| | | |
|---|---|---|
| 98-E-0022-05 | Decay Heat Removal Cooler E-35B 1R16 Thermal Performance Test | 001 |
| 94-E-0095-2014 | Heat load Evaluation | 1 |
| 98-E-0022-03 | Decay Heat Removal Cooler E-35A 1R15 Thermal Performance Test | 0 |
| 98E-0022-04 | Decay Heat Removal Cooler E-35B 1R215 Thermal Performance Test | 0 |

Testing Procedures and Results

| NUMBER | TITLE | REVISION |
|---|---|---|
| 98-E-0022-02 | Decay Heat Removal Cooler E-35A, Thermal Performance Test | 0 |
| 98-E-0022-04 | Decay Heat Removal Cooler E35B, 1R15, Thermal Performance Test | 0 |
| 98-E-0022-03 | Decay Heat Removal Cooler E-35A,1R15, Thermal Performance Test | 0 |
| 98E-0022-03 | Decay Heat Removal Cooler E-35B, 1R16, Thermal Performance Test | 0 |

Section 1R11: Licensed Operator Requalification

OLTS Report 9 list (NRC)

ANO Unit 1 licensed operator training list

Open Simulator Discrepancy Report (reviewed all 44 records)

Closed Simulator discrepancy report from January 2003 through July 11, 2005 (reviewed 600 records) with the following detailed package reviews:

DR 05-0079, closed, topic was emergency diesel generator loading rates

DR 05-0081, closed, topic was main turbine response to loss of all steam

DR 02-0244, closed, topic was heater drain pump impact on main feed system flows and pressures

DR 03-0073, closed, topic was heater drain tank level and recirc valve position

DR 03-0090, closed, topic was heater drain tank level control after drain pump trip

DR 03-0117, closed, topic was heater drain tank high level bypass capacity

DR 03-0202, closed, topic was OTSG levels posttrip

DR 05-0075, closed, topic was reactor trip setpoints

LER 50-313-2003-001, August 29, 2003, "Reactor Trip due to Automatic Actuation of the Reactor Protection System on High Reactor Coolant System Pressure and Actuation of the EFW System Resulting from a Lightning-Induced Closure of the Main Turbine Governor Valves," Corresponding simulator file, Attachment R-15

Annual Operability Test packages
Steady state power test (100 percent)
Transients Reviewed:

Simultaneous closure of both main steam isolation valves
Trip of one reactor coolant pump
Maximum rate power ramp
Real time test package

SBT package - reviewed one scenario package with a loss of offsite power as the main event

Simulator Core Reload Acceptance Test, DG-TRNA-015-CORETEST, Revision 0, with enclosed Unit 1 attachments

Simulator CAE file for Heater Drain Pump B trip test, Attachment R-14

STM 1-20, Figure 20-01, "Simplified Condensate System," Revision 7

PID —205, Sheet 2, "Condensate System"

Latest PSA Risk Table for Unit 1 Highest Risk Operator Actions, October 2004

Simulator Modification Control, DG-TRNA-015-SIMCONTROL, Revision 0

Simulator Configuration Control, EN-TQ-202, Revision 0

Scenarios: SES-1-004, SES-1-019

JPMs A1JPM-RO-EOP01, -EOP04, -PZR02, -EAL06, -AOP14, and -EDG05

Operations On-Shift Training Instruction Plan: "Mode 3 Operation Contingencies"

<u>Operating Procedures</u>

| NUMBER | TITLE | REVISION |
|---|---|---|
| 1063.008 | Operations Training Sequence | 34 |
| EN-TQ-201 | Systematic Approach to Training | 0 |
| TQF-201-1M05 | Remedial Training Plan | 2 |
| ENS-NS-112 | Medical Program and Physicals | 3 |

CR ANO-1-2003-00796, P-8A heater drain pump trip on July 25, 2003

Root Cause Analysis Report, "P-8A Heater Drain Pump Motor Winding Failure," September 10, 2003

CR ANO-1-2003-00987, P-8B heater drain pump trip on September 19, 2003

Root Cause Analysis Report, "Failure to Meet Reactivity Management Expectations," dated December 1, 2004

Section 1R12: Maintenance Effectiveness

CRs

| | | |
|---|---|---|
| ANO-2-2003-1257 | ANO-2-2004-0041 | ANO-2-2005-0385 |
| ANO-2-2003-1567 | ANO-2-2004-0379 | ANO-2-2005-0414 |
| ANO-2-2003-1574 | ANO-2-2004-0389 | ANO-2-2005-0807 |
| ANO-2-2003-1575 | ANO-2-2004-0784 | ANO-2-2005-0995 |
| ANO-2-2003-1591 | ANO-2-2004-1103 | ANO-2-2005-2006 |
| ANO-2-2003-1680 | ANO-2-2004-1916 | ANO-2-2005-2111 |

Miscellaneous

Maintenance Rule Database, Unit 2 HPSI
System Performance Indicator, HPSI - Arkansas Unit 2

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

CR

ANO-C-2005-1205

ERs

| | |
|---|---|
| 963555 I103 | 963555 R112 |
| 963555 R101 | ANO-1996-3555-056 |

Miscellaneous

MAI 74687

Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| 1000.152 | Unit 1 & 2 Fire Protection System Specifications | 3 |
| 1000.120 | ANO Fire Watch Program | 10 |
| COPD024 | Risk Assessment Guidelines | 16 |

Work Order

50268810 01

Section 1R14: Operator Performance During Nonroutine Plant Evolutions and Events

CRs

| | |
|---|---|
| ANO-2-2005-1969 | ANO-2-2005-2191 |
| ANO-2-2005-2193 | ANO-2-2005-2192 |

Operating Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| 2203.003 | CEA Malfunction | 15 |
| 2105.009 | CEDM Control System Operation | 21 |

Work Order

00070272 01

Section 1R16: Operator Workarounds

CR

ANO-C-2005-1520

Section 1R19: Postmaintenance Testing

CRs

| | | |
|---|---|---|
| ANO-1-2005-0884 | ANO-2-2005-0385 | ANO-2-2005-0948 |
| ANO-1-2005-0895 | ANO-2-2005-0659 | ANO-2-2005-1673 |
| ANO-1-2005-0900 | ANO-2-2005-0747 | ANO-2-2005-1754 |
| ANO-1-2005-1208 | ANO-2-2005-0775 | ANO-2-2004-1923 |
| ANO-2-1997-0055 | ANO-2-2005-0782 | ANO-C-2005-1593 |

ER

ANO-2002-0083-000

Work Orders

| | | |
|---|---|---|
| 00057097 03 | 00071637 01 | 50999668 01 |
| 00063471 01 | 00071637 03 | 51006765 01 |
| 00063618 01 | 50254113 01 | 51006909 01 |
| 00064655 01 | 50967812 01 | 51007157 01 |
| 00069039 01 | 50976843 01 | |
| 00071184 01 | 50976851 01 | |

Section 1R22: Surveillance Testing

CRs

ANO-C-2004-0353 ANO-C-2005-1218

ER

ANO-2003-0235, Revisions 0 and 1

Miscellaneous

| NUMBER | TITLE | REVISION |
|---|---|---|
| TD V085.0080 | Maintenance Manual for Velan 2 ½" - 24" Forged Bolted Bonnet Gate and Globe Valves and Bolted Cover Check Valves | N/A |
| TD V085.0040 | Maintenance Manual for Velan 2" - 24" Cast and Forged Pressure Seal Gate, Globe Parallel Slide and Check Valves | N/A |
| TD V085.0060 | Instruction Manual for Installation, Operation and Maintenance of Velan Pressure Seal Forged Gate, Stop, Stop Check, and Check Valves | N/A |

Operating Procedures

| NUMBER | TITLE | REVISION |
|---|---|---|
| 2104.005 | Containment Spray | 43 |
| 2104.007 | Control Room Emergency Air Conditioning and Ventilation | 27 |
| 2104.039 | HPSI System Operation | 42 |
| 2304.006 | Unit 2 Gaseous Process Radiation Monitoring System Calibration | 17 |
| 2304.016 | Unit 2 Process Radiation Monitoring Monthly Test | 16 |
| 2402.143 | Disassembly, Inspection and Reassembly of 2SI-12 | 1 |

Work Orders

00067969 02 50967615 01 51003781 01
50618124 01 50967812 01

1EP2: Alert and Notification System Testing

Alert and Notification System Report for Arkansas Nuclear One, Revised February 13, 1996

1EP3: Emergency Response Organization Augmentation

Emergency Response Staffing Drill, December 2004
Emergency Response Staffing Drill, December 2003

1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

Quarterly Self Assessment Report, Fourth Quarter 2003
Quarterly Self Assessment Report, First Quarter 2004
Quarterly Self Assessment Report, LO-ALO-C-2004-145
Biennial Roll-Up Report, Second and Third Quarters 2004
Quarterly Self Assessment Report, Fourth Quarter 2004
Peer Group Assessment, November 17, 2003
Peer Group Assessment, 2004 Dress Rehearsal Exercise
Peer Group Assessment, 2004 Biennial Evaluated Exercise
EP 2003-0064, Full Scale Drill, November 5, 2003
EP 2004-0037, Full Scale Drill, September 15, 2004
EP 2004-0045, Full Scale Drill, October 20, 2004
EP 2004-0053, Full Scale Drill, November 17, 2004
EP 2005-0011, Full Scale Drill, June 1, 2005
EP 2004-0050, Environmental Sampling Drill, November 19, 2004
EP 2004-0051, PASS Drill, December 1, 2004

4OA1: Performance Indicator Verification

EPIP 1903.011, "Emergency Response/Notifications," Attachment 6, "Protective Actions for General Emergency," Revision 28-00-0

Drill Schedule, 2004

Drill Schedule, 2005

Entergy Nuclear South EP Exercise and Drill Guide, October 2001

Desk Guide EP-006, "Drill/Exercise Manual Addendum," April 2005, Revision 2

## LIST OF ACRONYMS

| | |
|---|---|
| ANO | Arkansas Nuclear One |
| CAP | corrective action program |
| CEA | control element assembly |
| CFR | *Code of Federal Regulations* |
| CR | condition report |
| EFW | emergency feedwater |
| ER | engineering request |
| ERV | electromatic relief valve |
| GPD | gallons per day |
| HELB | high energy line break |
| HPI | high pressure injection |
| HPSI | high pressure safety injection |
| I&C | instrumentation and control |
| ICS | integrated control system |
| LER | licensee event report |
| MC | manual chapter |
| NCV | noncited violation |
| NFPA | National Fire Protection Association |
| SG | steam generator |
| SSC | structure, system, and component |
| TI | temporary instruction |
| URI | unresolved item |

ATTACHMENT 2

PHASE 3 EVALUATION, DAMAGED REACTOR COOLANT PUMP SEAL ARKANSAS NUCLEAR ONE, UNIT 2