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

January 29, 2004

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

SUBJECT: ARKANSAS NUCLEAR ONE - NRC INTEGRATED INSPECTION REPORT 05000313/2003005, 05000368/2003005, and 07200013/2003003

Dear Mr. Forbes:

On December 31, 2003, the US 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 January 7, 2004, 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.

This report documents five self-revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements; however, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these five findings as noncited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in Section 4OA7 of 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, D.C. 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, D.C. 20555-001; and the NRC Resident Inspector at Arkansas Nuclear One, Units 1 and 2, facility.

In accordance with 10 CFR 2.790 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/

Jeffrey A. Clark, Chief
Project Branch D
Division of Reactor Projects

Dockets: 50-313
50-368
72-13
Licenses: DPR-51
NPF-6

Enclosure:
NRC Inspection Report 05000313/2003005, 05000368/2003005, and 07200013/2003003
w/Attachment: Supplement Information

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ADAMS: √ Yes ☐ No Initials: __JAC__ **DMB (IE35)**
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

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RII/SRI:DRP/3	RI:DRP/D	RI:DRP/D	PE:DRP/E	SRI:DRP/D
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E	**E**	**E**	**/RA/**	**E**
1/8/04	1/9/04	1/9/04	1/29/04	1/9/04

C:DRS/PSB	C:DRS/EB	C:DRP/D		
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1/29/04	1/29/04	1/29/04		

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-313, 50-368, 72-13
Licenses:	DPR-51, NPF-6
Report:	05000313/2003005, 05000368/2003005, and 07200013/2003003
Licensee:	Entergy Operations, Inc.
Facility:	Arkansas Nuclear One, Units 1 and 2
Location:	Junction of Hwy. 64W and Hwy. 333 South Russellville, Arkansas
Dates:	September 21 through December 31, 2003
Inspectors:	E. Crowe, Resident Inspector R. Deese, Senior Resident Inspector J. Dixon, Resident Inspector E. Garcia, Senior Inspector, Fuel Cycle and Decommissioning Branch C. Johnson, Senior Reactor Inspector, Engineering Branch J. Blair Nicholas, Ph.D., Senior Health Physicist, Plant Support Branch D. Stearns, Project Engineer, Projects Branch E K. Weaver, Senior Resident Inspector, Turkey Point
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Approved By:	Jeffrey A. Clark, Chief, Project Branch D Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000313/2003005, 05000368/2003005, and 07200013/2003003; 9/21/03 - 12/31/03; Arkansas Nuclear One, Units 1 and 2; Surveillance Testing, ALARA Planning and Controls, Problem Identification and Resolution, and Event Followup.

This report covered a 3-month period of inspection by resident inspectors and announced inspections by a regional senior health physics inspector, a regional senior reactor inspector, and a regional senior independent spent fuel storage installation inspector. Five Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." 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. A noncited violation of 10 CFR Part 50, Appendix B, Criterion V, revealed itself when licensee personnel failed to prescribe an adequate procedure for inspecting the counterbore region of mechanical nozzle seal assemblies prior to their installation on the bottom of the Unit 2 pressurizer. This led to an inadequate counterbore in which material left in the counterbore area allowed leakage through an unanalyzed leak path, allowing boric acid to come into contact with the outside of the carbon steel pressurizer vessel.

  This finding is greater than minor because it was analogous to Example 2.e in Appendix E of Manual Chapter 0612 because procedures impacted the ability of seals to perform their function. This finding has very low safety significance because the amount of leakage was extremely small and no degradation to the pressurizer or mechanical nozzle seal assembly occurred due to boric acid corrosion (Section 4OA2).

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion V, revealed itself when a Unit 2 reactor operator did not follow the prescribed procedure for movement of an individual control element assembly during postmaintenance testing. The reactor operator positioned the control element drive mechanism control system mode selector switch to the "manual group" instead of the "manual individual" position, and began control element assembly insertion. This resulted in eight, instead of one, control element assemblies being inserted into the core and caused the core protection calculator to initiate an unplanned reactor protection system reactor trip.

  This finding is greater than minor because it was analogous to Example 4.b in Appendix E of Manual Chapter 0612 because an operator error caused a reactor trip. This finding has very low safety significance because no other complicating events were caused by the error and all mitigating systems remained available to the operators (Section 4OA3).

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, revealed itself when licensee personnel in Unit 2 did not take prompt corrective action to repair a faulty power switch in the power supply to Control Element Assembly 43. The power switch was determined to be the cause of two missing phases on different Control Element Assembly 43 coils and was not repaired for 3 months. The failure to repair it subsequently led to the dropping of Control Element Assembly 43 fully into the reactor core, initiating an unplanned downpower event.

  This finding is greater than minor because it affected the initiating events cornerstone objective of limiting the likelihood of those events that upset plant stability during power operations, in that it led to an unplanned downpower. This finding has very low safety significance because Control Element Assembly 43 was able to perform its intended safety function (Section 4OA3).

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion III, revealed itself when licensee personnel in Unit 2 did not correctly translate the designed configuration of the Unit 2 high pressure safety injection system cold leg flow transmitters into the component database and the work instructions to replace the transmitters. The flow transmitter for the C-Leg 2FI-5054 was subsequently installed with its high and low pressure taps reversed, rendering the indicator inoperable for nearly 1 year, until discovered during a surveillance test.

  This finding is greater than minor because it was analogous to Example 5.b in Appendix E of Manual Chapter 0612, because it involved returning a system to service after improper installation of a plant component. The improper installation of the high pressure safety injection C-Leg flow transmitter would have provided confusing indications to operators under accident conditions. This finding has very low safety significance because no other anomalous conditions were found which would have complicated operation of the high pressure safety injection system and the system would have performed its safety function with proper operator diagnosis (Section 1R22).

Cornerstone: Occupational Radiation Safety

- Green. The inspector reviewed three examples of a self-revealing, noncited violation of 10 CFR 20.1501(a), because the licensee failed to perform required radiation surveys to evaluate radiological conditions in rooms affected by radiation streaming from a stuck fuel assembly in the fuel transfer carriage and to ensure compliance with 10 CFR 20.1902(a) and (b). Specifically, on

October 1, 2003, two examples involved the licensee’s failure to survey and evaluate the radiological conditions in the Unit 2 penetration emergency exhaust ventilation room and the upper north piping penetration area located inside the controlled access area. Subsequent radiation surveys of these two areas identified general area radiation dose rates greater than 100 millirems per hour, requiring the areas to be posted as high radiation areas. The third example involved the licensee’s failure to survey and evaluate radiological conditions in the Unit 2 lower north electrical penetration area located outside the controlled access area. Radiation surveys of this area indicated the highest general area dose rate of 80 millirems per hour, requiring the area to be posted as a radiation area. These findings are in the licensee’s corrective action program as Condition Report ANO-2-2003-1405.

The finding is greater than minor because it was associated with one of the occupational radiation safety cornerstone attributes (exposure/contamination control) and the finding affected the associated cornerstone objective to ensure the adequate protection of the worker's health and safety from exposure to radiation from radioactive material. The inspector processed the finding through the occupational radiation protection significance determination process because the occurrence involved unplanned or unintended doses (resulting from actions or conditions contrary to licensee procedures) which could have been significantly greater as a result of a single minor, reasonable alteration of the circumstances. However, because the finding was not an as low as is reasonably achievable planning and control issue, there was no overexposure or substantial potential for personnel overexposure, and the finding did not compromise the licensee’s ability to assess dose, the finding had no more than very low safety significance (Section 2OS2).

B. Licensee-Identified Violations

A violation of very low safety significance which was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and its 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 until November 15, 2003, when the unit was shutdown to repair its main transformer after high gas levels were discovered in two phases of the transformer. Unit 1 was restarted on December 10, 2003, and returned to 100 percent power on December 12 and remained at or near there for the remainder of the inspection period.

Unit 2 began the inspection period in a coastdown to a refueling outage at 68 percent rated thermal power. On September 23, 2003, the unit shutdown for that refueling outage which lasted until October 14. The unit subsequently returned to 100 percent power on October 17 and remained there until December 24 when operators shut down the unit to repair the main condenser steam seal expansion joint which was hampering the ability to maintain condenser vacuum. Unit 2 was restarted on December 29 achieved 100 percent power on December 30, 2003, and remained there for approximately 2 hours. Power was then reduced to 81 percent due to a hydraulic fluid leak on the Main Feedwater Pump A, which required the shutdown of the pump. On December 31, 2003, Unit 2 achieved 100 percent power and remained there for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial System Walkdowns. The inspectors performed two partial system walkdowns of systems important to reactor safety during this inspection period in order to verify the operability of the systems. The inspectors reviewed system operating instructions and required system valve and breaker lineups and then compared them to operator logs, system control room indications, valve positions, breaker positions, and control circuit indications to verify these components were in their required configuration for making their systems operable. The inspectors also examined component materiel condition. The following walkdown inspections were conducted:

- On October 17, 2003, the inspectors performed a partial system walkdown of the Unit 2 high pressure safety injection (HPSI) system following maintenance and modifications during Refueling Outage 2R16.

- On September 25-27, 2003, the inspectors performed a partial system walkdown of the Unit 2 red train engineering safety features electrical DC system when the green train engineering safety features Battery 2D12 was removed from service during its replacement.

Complete System Walkdown. On October 27, 2003, the inspectors performed a complete system walkdown of accessible portions of the emergency cooling pond (ECP) and associated piping. During this walkdown, the inspectors verified correct valve alignment, electric power availability, and no adverse material condition of system components. Positions of valves and electrical power breakers were compared to Procedure 2104.029, "Service Water System Operation," Revision 53. The inspectors also reviewed condition reports (CRs) generated during the previous year and also reviewed Maintenance Action Items (MAIs) 83502 and 65810 for sounding of the level of water in the ECP. These two MAI's were performed in accordance with Procedure 1306-019, "Annual Emergency Cooling Pond Sounding," Revision 7.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors referenced the Fire Hazards Analysis Report, Revision 7, during the following inspections of six fire areas to ensure that conditions were consistent with the requirements of the licensee's fire protection program for fire protection systems design, control of transient combustibles and ignition sources, fire detection and suppression capability, fire barriers, and any related compensatory measures:

- Fire Zone 2032-J, Unit 2 containment, south side on October 5, 2003
- Fire Zone 2006LL, Unit 2 317-foot elevation auxiliary building on October 6, 2003
- Fire Zone 2033-J, Unit 2 containment, north side on October 7, 2003
- Fire Zone 70, Unit 1 auxiliary building, 35-foot elevation on October 20,2003
- Fire Zone 2099-W, Unit 2 west DC equipment room on October 23, 2003
- Fire Zone 2100, Unit 2 south switchgear room on October 31, 2003

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

External Flooding. On December 15, 2003, the inspectors verified that the licensee's flooding mitigation plans and equipment were consistent with the licensee's design requirements and the risk assumptions in the Updated Final Safety Analysis Report (UFSAR). The inspectors also reviewed the licensee's flood protection documents, including Procedures 1203.025, "Natural Emergencies," Revision 19, and 2203.008, "Natural Emergencies," Revision 8. The inspectors conducted walkdowns of Units 1 and 2 areas susceptible to external flooding to verify that risk-significant equipment was adequately protected.

Internal Flooding. On October 31, 2003, the inspectors reviewed one sample of the licensee's internal flooding protection features associated with the general flood protection measures for the Unit 2 Emergency Diesel Generator (EDG) 2K-4B, Room 2094. The inspectors performed a walkdown of the area reviewing internal flooding vulnerabilities. Also, the inspectors reviewed the protective features and procedures for mitigating the impact of any flooding. In specific detail, the inspectors reviewed installed flood protection measures associated with watertight Doors 261 and 251 which serve to isolate Room 2094 in the event of internal flooding.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.HS)

a. Inspection Scope

Biennial Programmatic and Functional Performance Review. Between December 15-23, 2003, the inspectors reviewed applicable licensee documents related to Unit 2 EDG 2K-4A heat exchangers and ECP performance testing, including Engineering Request ANO-2002-0960-000, "Review of 2002 / Cycle 16 Thermal Performance Testing of U2 EDG's," Calculation 91-R-2013-01, "Service Water Performance Testing Methodology," Calculation 91-E-0099-10, "ECP Peak Temperature and Inventory Loss Analysis Summary," and the UFSAR. The purpose of this biennial review was to verify (1) that testing, inspection/maintenance, or monitoring of biotic fouling controls are singularly or in combination adequate to ensure proper heat transfer; (2) methods used to inspect heat exchangers are consistent with expected degradation; (3) established acceptance criteria are consistent with accepted industry standards, or equivalent, including acceptability of the cleaning interval; (4) as found results are appropriately dispositioned such that the final condition is acceptable; (5) chemical treatments, tube leak monitoring, methods used to control biotic fouling corrosion, and methods to control macrofouling are sufficient to ensure required heat exchanger performance; (6) condition and operation are consistent with design assumptions; (7) the potential for water hammer has been evaluated; (8) excessive vibrations are not exhibited during operation that could potentially damage their tubes or tube sheets; (9) redundant and infrequently used heat exchangers are flow tested periodically at maximum design flow; and (10) the performance of ultimate heat sinks and their subcomponents by verifying sufficient reservoir capacity, free from clogging due to macrofouling, and adequate controls for biotic fouling. The identification and resolution of problems aspects were addressed in the biennial inspection and are reported under NRC Inspection Report 05000313/2003008; 05000368/2003008.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

1. Performance of Unit 2 Nondestructive Examination (NDE) Activities Other than Steam Generator (SG) Tube Inspections

a. Inspection Scope

The procedure requires review of two or three types of NDE activities (volumetric, surface, and visual). The inspectors reviewed multiple examples of all three types.

The procedure requires review of one or two examinations from the previous outage with recordable indications that were accepted for continued service. The inspectors reviewed one such examination (SG Cold Leg Weld 03-05).

If the licensee completed welding on the pressure boundary for Class 1 or 2 systems since the beginning of the previous outage, the procedure requires verification for one-to-three welds that acceptance and preservice examinations were done in accordance with American Society of Mechanical Engineers (ASME) Code. The inspectors verified two welds (Safety Injection System Welds FW 83 and 84).

The procedure requires verification that one or two ASME Section XI Code repairs or replacements meet Code requirements. The inspectors verified two Section XI repairs mechanical nozzle seal assembly (MNSA) clamps.

The inspectors verified, through direct observation or record review, that ultrasonic, eddy current, liquid penetrant, radiographic, or visual examinations of the systems/components below were performed in accordance with Code requirments.

System	Component/Weld Identification	Examination Method
Low Pressure Safety Injection	Pipe Weld (12 inch), Weld 54-006	Ultrasonic
HPSI	Pipe (Integrally Welded Attachment 2CCA-23-H13)	Liquid Penetrant
Reactor Coolant	Reactor Pressure Vessel (RPV) Head Incore Instrumentation (ICI) Nozzles: ASME Code Section XI repair	Liquid Penetrant

System	Component/Weld Identification	Examination Method
Pressurizer	Pressurizer Heater Penetrations ASME Code Section XI Repair	MNSA Clamp
Pressurizer Spray Line	Pipe Restraint Support 2CCA-15-H13	Visual (VT-3)
Safety Injection	Pipe (Integrally Welded Attachment 2CCA-23-H13)	Visual (VT-3)
Reactor Coolant	SG Cold Leg, Weld 03-005	Ultrasonic
Safety Injection	Weld FW-84, 84R1, and 84R2	Radiography
Safety Injection	Weld FW-83 and 83R1	Radiography
Reactor Coolant	RPV Head (ICI and Control Element Drive Mechanism [CEDM] Nozzles)	Eddy Current Ultrasonic Liquid Penetrant Visual

During the review of each examination, the inspectors verified that the correct NDE procedures were used, that examinations and conditions were as specified in the procedure, and that test instrumentation or equipment was properly calibrated and within the allowable calibration period. The inspectors also reviewed documentation such as radiographic film, ultrasonic records, and eddy current records to determine if the indications revealed by the examinations were compared against the ASME Code specified acceptance standards. This review also determined that indications were appropriately dispositioned.

The inspectors verified the NDE certifications of those personnel observed performing examinations or identified during review of completed examination packages.

b. Findings

No findings of significance were identified.

2. SG Tube Inspection Activities

a. Inspection Scope

SG tubes were not examined during this outage because Unit 2 SGs were replaced during Refueling Outage 2R14. In a letter dated November 22, 2002, as supplemented by a letter dated March 13, 2003, Entergy Operations Inc., submitted a request to revise the SG inservice inspection frequency requirements in Technical Specification 4.4.5.3.a. Specifically, the change requested was a 1-time, 40-month inspection interval following the first postreplacement inservice inspection which resulted in a C-1 classification. The NRC staff approved the request by letter dated April 29, 2003.

b. Findings

No findings of significance were identified.

3. RPV Head and Vessel Head Penetration Nozzles (TI 2515/150, Revision 2)

a. Inspection Scope

The inspectors determined from review and discussions with the licensee that susceptibility ranking calculations had increased the ranking for ANO Unit 2 from “moderate” to “high” based on time in service prior to the beginning of Refueling Outage 2R16.

Procedure TI 2515/150 requires review of 10 percent of vessel head nozzle volumetric and 5-10 percent of nozzle and/or J-groove surface examinations. The inspectors reviewed volumetric and surface examinations of 10 of 89 nozzles (11 percent), including J-groove weld surface (8 CEDM and 2 ICI nozzles.) The inspectors also verified that examination methods used were capable of identifying stress corrosion cracking.

The procedure requires review of one or two examinations from the previous outage with recordable indications from surface and volumetric examinations if applicable. There were no volumetric or surface examinations with recordable indications from the previous outage.

The procedure requires review of one or two ASME Section XI Code repairs done as a result of volumetric and surface examinations. The inspectors reviewed repairs to two ICI nozzles stemming from surface examinations (ICI nozzle repairs from indications in dye penetrant tests).

The procedure requires review of 5-10 percent of RPV head bare metal visual examination and three to five vessel head penetration nozzle examinations. The inspectors reviewed video from the top of the cooling shroud around approximately 10 CEDM nozzles and bare metal at all 8 ICI nozzles, or approximately 20 percent (estimated) of the head surface.

The inspectors observed NDE examinations performed at the vessel head from remote video feeds at the collection and analysis stations. The inspectors examined ultrasonic and eddy current data from 8 of 81 CEDM nozzles and two of 8 ICI nozzles, and dye penetrant tests results from 2 ICI nozzles. The inspectors verified that qualified personnel performed the examinations in accordance with approved procedures.

The inspectors observed a sample of the NDE performed on the RPV head. These included eddy current, ultrasonic, and dye penetrant examinations, as well as visual inspections of the bare surface of the vessel head where feasible. These examinations met the requirements specified in three NRC letters of October 9, 2003, granting relaxation requests from NRC Order EA-03-009 for the ICI nozzles, CEDM and bare metal visual examination.

The inspectors witnessed the visual inspection procedures and reviewed the video images obtained from the boroscope and video camera. This information adequately determined that there is no boron accumulation on top of the cooling shroud and insulation on the surface of the head in the area of the ICI nozzles. The inspection effort revealed no signs of deterioration in the physical condition of the reactor vessel head.

The inspectors also verified that the licensee had procedures in place to identify potential boric acid residue and leaks from pressure-retaining components.

b. Findings

No findings of significance were identified.

4. Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed inservice inspection-related CRs issued during the current and past refueling outage, and verified that the licensee identified, evaluated, corrected, and trended problems. In this effort, the inspectors evaluated the effectiveness of the licensee’s corrective action process, including the adequacy of the technical resolutions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed two sessions of licensed operator requalification training activities in the Units 1 and 2 simulators to assess the licensee's effectiveness in conducting the requalification program and to verify that licensed individuals received the appropriate level of training required to maintain their licenses. The specific observations are listed below:

- On November 20, 2003, the inspectors observed the Unit 1 licensed operator simulator qualification training Scenario A1SPG040201, "Steam Generator Tube Rupture," conducted for Unit 1 Training Cycle 4.

- On November 20, 2003, the inspectors observed the Unit 2 licensed operator simulator qualification training Scenario A2SPGLOR040201, "Natural Circulation Cooldown," conducted for Unit 2 Training Cycle 4.

The inspectors compared their observations for each of these scenarios to the applicable abnormal operating procedures, emergency plan procedures and applicable Technical Specifications. In addition, the inspectors attended the critiques following the scenarios held by the Units 1 and 2 training organizations to assess individual performance.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed performance-based problems involving three selected inscope structure, system, or components (SSCs) to assess the effectiveness of the Maintenance Rule Program. The inspectors independently verified that licensee personnel properly implemented 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The following equipment performance problems were reviewed:

- Repeat functional failures of the Unit 2 safety parameter display system
- Excessive seal leakage on Unit 1 decay heat removal Pump P-34B
- Repeat failures of Unit 1 south switchgear room Chiller VCH-4B

The inspectors focused the review on whether the SSCs that experienced problems were properly characterized in the scope of the program. They also reviewed whether the SSCs failure or performance problem was properly characterized. The inspectors assessed the adequacy of the licensee's significance classification for the SSCs. This included the appropriateness of the performance criteria established for the SSCs (if applicable) and the adequacy of corrective actions for SSCs classified in accordance with 10 CFR 50.65 a(1) as applicable.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors evaluated and discussed with the licensee the eight risk assessments listed below to verify that assessments were performed when required. The inspectors reviewed these assessed risk configurations against actual plant conditions and any inprogress evolutions or external events to verify that the assessments were accurate, complete, and appropriated for the conditions. In addition, the inspectors walked down the control room and plant areas to verify that compensatory measures identified by the risk assessments were appropriately performed.

- Repair of Unit 2 circulating water discharge piping manway leak on October 24, 2003.
- Unit 2 refueling outage shutdown risk with containment building open and reactor coolant system water level lowered for refueling on September 26, 2003
- Emergent maintenance on the Unit 1 emergency feedwater system on September 23-24, 2003
- Emergent maintenance on the Unit 1 auto-transformer due to an oil leak in the transformer on October 1, 2003
- Planned preventative maintenance on the Unit 2 containment spray system on October 23, 2003
- Emergent maintenance on Phase B of the Unit 2 auto-transformer on November 3, 2003
- Emergent maintenance on the Unit 1 main transformer during unplanned replacement of two phases from November 15 through December 12, 2003
- Planned maintenance to install and test a lightning-hardening modification on the Unit 1 electro-hydraulic control system on December 1, 2003

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed five operability determinations to assess the correctness of evaluations, the use of compensatory measures, if needed, and compliance with the Technical Specifications. The inspectors' review included a verification that operability determinations were made as specified by the licensee's Procedure LI-102, "Corrective Action Process," Revision 2, and Procedure 1015.047, "Condition Reporting Operability and Immediate Reportability Determinations," Revision 0. The technical adequacy of the determinations was reviewed and compared to the Technical Specifications, Technical Requirements Manual, UFSAR, and the associated licensing-basis documentation, as appropriate. The operability determinations that were reviewed were documented in the following CRs:

- CR ANO-2-2003-1283 — Sharp drop in Unit 2 condensate storage tank level
- CR ANO-1-2003-1030 — Operability of Unit 1 south switchgear room Cooler VCH-4B
- CR ANO-2-2003-0855 — Unit 2 HPSI flows in excess of Regulatory Guide 1.97 requirements
- CR ANO-2-2003-1352 — Boric acid accumulation on Unit 2 safety injection Tank C Isolation Valve 2CV-5043-2
- CR ANO-2-2003-1795 — Low oil level on the Unit 2 emergency feedwater turbine

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

Semiannual Review. The inspectors sampled three attributes in a semi-annual review of all operator workarounds listed on the licensee's operator workaround list for both Units 1 and 2. The cumulative effects of all workarounds on each unit were reviewed for:

- the reliability, availability, and potential for misoperation of a system
- potential affects on multiple mitigating systems
- the ability of operators to respond to plant transients or accidents in a correct and timely manner

Individual Workarounds. The inspectors reviewed the Units 1 and 2 operations concerns database which includes licensee identified operator workarounds. The following three operator workarounds were reviewed for their impact on mitigating systems, risk significance, documentation in the corrective action programs, and ability to implement abnormal or emergency operation procedures:

- 1-03-08: Inoperable Reactor Building Spray Pump B Discharge Pressure Transmitter PT-2425 on Unit 1

- 2-02-11 Intermittent EDG 2K-4B jacket water low pressure alarm on Unit 2

- 1-03-10 Inoperable level switch for the humidifier in the computer room Unit Cooler Assembly VUC-5A on Unit 1

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

For the three maintenance activities identified below, the inspectors observed the postmaintenance testing activities in the control room or locally and/or reviewed the test data obtained from the field. The inspectors observed whether the tests were performed in accordance with procedures, that the procedures' acceptance criteria were consistent with the Technical Specifications and the supporting license change application, and the results recorded met the test acceptance criteria. In addition, the inspectors verified that startup test deficiencies were recorded and resolved. These activities included:

- On October 9, 2003, the inspectors reviewed Work Order Package 00030088, Revision 1, for weld repairs to the Unit 2 safety injection system Tank 2T-2C Isolation Valve 2CV-5043-2 drain line cap.

- Following Refueling Outage 2R16, the inspectors reviewed Work Plan OP-2409.752, "2P-89C Precision Pump Element Modification," Revision 0, for the retest of the Unit 2 HPSI system conducted October 9-10, 2003, after extensive maintenance performed on it during the refueling outage.

- During the week of November 24, 2003, the inspectors reviewed Work Order Package 00030747, Revision 1, dated October 24, 2003, for the Unit 1 south emergency switchgear room Chiller VCH-4B. The inspectors also reviewed the November 26, 2003, monthly test and interviewed the system engineer.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

Unit 2 Refueling Outage. The inspectors reviewed the shutdown operations protection plan and contingency plans for the Unit 2 Refueling Outage 2R16, conducted September 23 through October 14, 2003, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the shutdown operations protection plan for key safety functions and compliance with the applicable Technical Specification when taking equipment out of service
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and an accounting for instrument error
- Controls over the status and configuration of electrical systems to ensure that Technical Specification and outage safety plan requirements were met and controls over switchyard activities
- Monitoring of decay heat removal processes
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition and controls to prevent inventory loss
- Controls over activities that could affect reactivity
- Maintenance of secondary containment as required by Technical Specification
- Refueling activities, including fuel handling
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing

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

Unit 1 Forced Outage. Because of degraded conditions in Phases B and C of the Unit 1 main transformer, licensee personnel conducted a forced outage from November 15 through December 12, 2003, to replace the transformer phases. The inspectors reviewed the outage plan and contingency plans to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth, specifically associated with licensee personnel's decision to maintain the plant at normal operating temperatures and pressures for the entire outage. During the outage, the inspectors also observed portions of the shutdown, monitored licensee configuration management, reviewed controls over the status and configuration of electrical systems, monitored controls over activities that could affect reactivity, reviewed trends associated with startup and ascension to full power operation. Finally, the inspectors reviewed licensee personnel's identification and resolution of problems related to the outage activities.

Unit 2 Forced Outage. On December 24, 2003, in response to problems with maintaining condenser vacuum, the licensee shutdown Unit 2 to repair the main condenser steam seal expansion joint. The licensee exited this forced outage on December 29, 2003. The inspectors reviewed the outage plan and contingency plans to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the outage, the inspectors reviewed computer trends for portions of the shutdown and cooldown, monitored licensee configuration management, reviewed controls over the status and configuration of mitigating systems, monitored controls over activities that could affect reactivity, reviewed trends associated with startup and ascension to full power operation. Finally, the inspectors reviewed licensee personnel's identification and resolution of problems related to the outage activities.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed from either the control room or locally the performance of and/or reviewed the documentation for the following surveillance test. This was done to verify that the surveillance test was performed in accordance with approved licensee procedures and met Technical Specification requirements. In addition, the applicable test data was also reviewed to verify whether they met Technical Specifications, UFSAR, and licensee procedure requirements.

- Unit 2 HPSI system full flow test performed on October 10, 2003, in accordance with Supplement 6 to Procedure 2104.039, "HPSI System Operation," Revision 42

b. Findings

Introduction. A Green noncited violation of 10 CFR Part 50, Appendix B, Criterion III, revealed itself when the licensee discovered that the Unit 2 HPSI C-Leg Flow Indicator 2FI-5043-2 was hooked up with its high and low pressure taps switched.

Description. On October 9, 2003, during the Unit 2 HPSI full flow surveillance test, operators noted that the indicated flow to the injection leg of the system which provided flow to the cold leg reactor coolant Loop C was not indicating properly. Troubleshooting by instrumentation and controls technicians uncovered that the flow transmitter for the C-Leg of the system was installed with its high and low pressure taps reversed.

Further research yielded the discovery that this flow transmitter had been installed in October 2002 for corrective maintenance purposes. Therefore, the existing flow transmitter had been installed incorrectly for nearly 1 year. The installation in October 2002 had been in accordance with the prescribed work package, but the work package did not contain proper information to swap the internals to ensure proper installation.

Unit 2 was constructed with Fischer-Porter flow transmitters for indication of individual HPSI leg flows to each reactor coolant loop. In 1983, the licensee implemented Design Change Package 83-2103 to replace the Fischer-Porter transmitters with Rosemount Model 1153D transmitters for the indication. Upon installation of the transmitters, licensee personnel noted that the old Fischer-Porter transmitters were configured differently than the new Rosemount transmitters because the high and low pressure taps were reversed if the transmitters were to be mounted in the same spot as the old transmitters. Since the tubing leading to the transmitters was already installed and rerouting it would be significantly more complicated, licensee personnel implemented a field change notice to the design change package to dismantle the replacement transmitters and rotate the process taps and electrical connections 180 degrees from a standard issue Rosemount transmitter. Licensee personnel implemented this change and the transmitters passed their retests and worked fine until the C-Leg transmitter failed in October 2002. Under MAI 331125, the failed transmitter was replaced with an unmodified standard issue Rosemount transmitter. The postmaintenance test for the transmitter replacement was limited to performing a string check of the transmitter which would not reveal an improperly hooked up transmitter. At that time, the only way to catch the error was during a full flow test of the HPSI system which was only performed during outages. As was the case, on October 9, 2003, during the HPSI full flow test during Refueling Outage 2R16, the problem revealed itself.

The modification change to swap the internals of the Rosemount transmitter was lost sometime between 1983 and 2002. The inspectors could not determine whether the initial action to swap internals was ever recorded in the licensee's component database or whether the information was lost during one of the licensee's switches to newer databases. Nonetheless, the licensee failed to maintain adequate control over the installed configuration of the transmitters in the plant which led to the improper installation in 2002 and a condition where the transmitter for the C-Leg of HPSI was installed improperly.

Analysis. The inspectors considered this issue to be more than minor because it was analogous to Example 5.b in Appendix E of Manual Chapter 0612, because it involved returning a system to service after improper installation of a plant component. The inspectors assumed that the improper installation of the HPSI C-Leg flow transmitter would have provided confusing indications to operators, potentially leading to system misoperation and, therefore, this issue fell under the mitigating systems cornerstone. The inspectors also assumed that no other anomalous conditions existed which would have complicated operation of the HPSI system and that the HPSI system would have performed its safety function with proper operator diagnosis. The inspectors considered the issue to be of very low safety significance because it did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

Enforcement. The inspectors determined that the improper installation of the C-Leg flow transmitter was a violation of 10 CFR Part 50, Appendix B, Criterion III, which requires that the design of components is correctly translated into specifications and instructions. Contrary to this, between 1983 and October 2002, licensee personnel failed to correctly translate the designed configuration of the Rosemount transmitters for the leg flows in the Unit 2 HPSI system into the specifications in their component database and the work instructions to replace the transmitters. Because of the very low safety significance of this condition and because the licensee included this condition in their corrective action program in CR ANO-2-2003-1566, this violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000368/2003005-01). This CR documented ANO personnel's efforts to correct the component database to ensure proper installation of replacement transmitters in the future.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed two samples of the licensees emergency plan and procedures as follows:

- On November 5, 2003, the inspectors observed portions of the announced emergency preparedness drill conducted to evaluate emergency response organization performance by focusing on the risk-significant activities of classification, notification, and protective action recommendations. The inspectors also assessed personnel recognition of abnormal plant conditions, the transfer of emergency responsibilities between facilities, communications, and the overall implementation of the emergency plan. The drill was conducted using the Unit 1 simulator, the technical support center, the operations support center, and the emergency operations facility.

- On November 18, 2003, the inspectors observed a simulator-based training evolution which the licensee had identified as contributing to their emergency planning performance indicators. The evolution was conducted to evaluate the shift personnel's emergency response performance by focusing on the risk-significant activities of classification, notification, and protective action recommendations. The inspectors also assessed personnel recognition of abnormal plant conditions and implementation of the emergency plan. The drill was conducted using the Unit 1 simulator.

b. Findings

No findings of significance were identified.

Cornerstone: Occupational Radiation Safety (OS)

2. RADIATION SAFETY

2OS2 As Low as is Reasonably Achievable (ALARA) Planning and Controls (71121.02)

a. Inspection Scope

The inspector interviewed radiation protection personnel and radiation workers involved in high dose rate, high exposure, and airborne area work activities. The inspector conducted independent radiation surveys of selected work areas and assessed the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas; radiation worker practices; and work activity dose results against procedural and regulatory requirements. The inspector discussed changes and trends related to the ALARA program with the radiation protection superintendent and the ALARA program supervisor. No high exposure work activities in high radiation or airborne areas were performed during the inspection. Therefore, this aspect of the inspection procedure could not be evaluated.

The inspector interviewed radiation protection staff and other radiation workers to determine the level of planning, communication, ALARA practices, and supervisory oversight that was integrated into work planning and work activities. Additionally, the inspector attended ALARA prejob briefings for radiography work (RWP 2003-2424) and reactor building sump cleanup (RWP 2003-2422). The inspector reviewed initial and emergent work scopes and estimated person-hour information provided to the radiation protection group for accuracy. The following radiation protection program controls, planning, and preparation items were reviewed and compared with procedural and regulatory requirements to assess the licensee's program to maintain occupational exposures ALARA during the Refueling Outage 2R16:

- ALARA program procedures
- Processes, methodology, and bases used to estimate, justify, adjust, track, and evaluate personnel exposures
- Plant collective exposure history for the past 3 years, current exposure trends, source term measurements, and 3-year rolling average dose information
- Refueling Outage 2R16 exposure data
- ALARA and radiological work planning, inprogress reviews, and postjob reviews for five RWP packages that resulted in some of the highest personnel collective exposures during the Refueling Outage 2R16
- Incorporation of postjob review identified problems from five RWP packages into the licensee's corrective action program
- Hot spot tracking and reduction program, including inspection and posting verification of six hot spots throughout the controlled access area
- Use and results of administrative and engineering controls to achieve dose reductions, including five temporary shielding records planned and installed during the Refueling Outage 2R16 and four long-term shielding records
- 2003 year-to-date individual exposures for nonoutage and outage periods of selected work groups (radiation protection, operations, mechanical maintenance, electrical maintenance, and instruments and controls)
- Plant related source term evaluation and control/reduction strategy
- Declared pregnant worker and embryo/fetus dose evaluation, monitoring, and controls for one currently declared pregnant worker
- ALARA managers committee and ALARA subcommittee meeting minutes for meetings since January 2003
- Quality Assurance Audit Report (QA) 14-2003-ANO-1 which evaluated the radiation protection program and included an overview of the ALARA program
- Quality Assurance Surveillance Report (QS) 2003-ANO-023 which evaluated RWP revision justifications and Quality Assurance Surveillance Report (QS) 2003-ANO-043 which evaluated general radiation work practices
- Radiation protection department quarterly self-assessments for the first 6 months of 2003 which provided a comprehensive assessment of the radiation protection program (ALO-C-2003-0001 and ALO-C-2003-0002)

- Summary of corrective action documents written since the last inspection of the ALARA program performed in January 2003 and selected documents relating to exposure tracking, higher than planned exposure levels, radiation worker practices, repetitive, and significant individual deficiencies.

- Implementation of the licensee's respiratory protection program for compliance with 10 CFR 20.1703(f)

The inspector completed 15 of the required inspection procedure samples.

b. Findings

Introduction. The inspector reviewed three examples of a self-revealing Green, noncited violation of 10 CFR 20.1501(a), because the licensee failed to perform required radiation surveys in Unit 2 to ensure compliance with 10 CFR 20.1902(a) and (b).

Description. On October 1, 2003, during the performance of a protective tagout associated with the Postaccident Hydrogen Analyzer B, two operators in the upper north piping penetration room (360-foot elevation) received unanticipated dose rate alarms. The operators exited the area and immediately contacted radiation protection. The dose rates indicated on their electronic alarming dosimeters were approximately 300 millirems per hour. The dose rate alarm set point was 100 millirems per hour. The higher than normal radiation levels were attributed to a stuck fuel assembly in the fuel transfer carriage between the Unit 2 containment and the spent fuel pool causing a radiation streaming effect through a gap between containment and the auxiliary building which was directed along the curvature of the containment wall. Upon notification of the dose rate alarms, radiation protection secured and controlled the affected areas. Subsequent radiation surveys of the affected areas resulted in posting two rooms located inside the Unit 2 auxiliary building controlled access area as high radiation areas and one room located outside the Unit 2 controlled access area as a radiation area. Two examples included the penetration emergency exhaust ventilation room (335-foot elevation) and the upper north piping penetration area (360-foot elevation) which were posted prior to the incident as radioactive material, RWP required, and contamination monitoring required. Based on the results of radiation surveys performed while the fuel assembly was stuck, these rooms were posted as high radiation areas. General area dose rates in the rooms ranged between 22 and 780 millirems per hour. The third example involved the lower north electrical penetration area (372-foot elevation) located outside the Unit 2 controlled access area which was not posted nor radiologically controlled prior to the incident. Based on the results of radiation surveys performed while the fuel assembly was stuck, this room could have been posted as a radiation area but was conservatively posted as a high radiation area. The highest general area dose rate in the room was 80 millirems per hour. The licensee has an administrative dose rate of 80 millirems per hour for posting an area as a high radiation area.

Analysis. The inspector determined that the licensee's failure to perform radiation surveys required by 10 CFR 20.1501(a) were three examples of a performance deficiency. The finding is greater than minor because it was associated with one of the occupational radiation safety cornerstone attributes (exposure/contamination control), and the finding affected the associated cornerstone objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material. The inspector processed these issues through the Occupational Radiation Protection Significance Determination Process because the occurrence involved unplanned or unintended doses (resulting from actions or conditions contrary to licensee procedures) which could have been significantly greater as a result of a single minor, reasonable alteration of the circumstances. These issues were determined to be a "Green" finding because they were not an ALARA planning and control issue, there was no personnel overexposure or substantial potential for personnel overexposure, and the licensee's ability to assess dose was not compromised.

Enforcement. 10 CFR 20.1501(a) requires, in part, that a licensee make or cause to be made, surveys that are necessary for the licensee to comply with the regulations in this part to evaluate the radiation levels, the concentrations or quantities of radioactive material, and the potential radiological hazards. Radiation surveys were necessary to verify compliance with 10 CFR 20.1902(a) and (b) which require radiation areas and high radiation areas to be conspicuously posted, respectively. Section 20.1003 of 10 CFR defines a radiation area as an area, accessible to individuals, in which radiation levels could result in an individual receiving a dose equivalent in excess of 0.005 rem (5 millirems) in 1 hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates. Section 20.1003 of 10 CFR also defines a high radiation area as an area, accessible to individuals, in which radiation levels from radiation sources external to the body could result in an individual receiving a dose equivalent in excess of 0.1 rem (100 millirems) in 1 hour at 30 centimeters from the radiation source or 30 centimeters from the surface that the radiation penetrates.

The failure to perform required radiation surveys and evaluate radiological hazards associated with the stuck fuel assembly in the fuel transfer carriage between the Unit 2 containment and the spent fuel pool is being identified as three examples of a 10 CFR 20.1501(a) violation. Because the three examples of the finding were of very low safety significance and were entered into the corrective action program as CR ANO-2-2003-1405, these three examples of a violation were treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000368/2003005-02).

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the four performance indicators on both units listed below for the period from October 2002 through September 2003. The inspectors verified: (1) the accuracy of the performance indicator data reported during that period and (2) used the performance indicator definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, to verify the basis in reporting for each data element.

Reactor Safety Cornerstone

- Safety system unavailability, emergency AC power systems, Units 1 and 2
- Safety system unavailability, high pressure injection systems, Units 1 and 2
- Safety system unavailability, residual heat removal systems, Units 1 and 2
- Safety system unavailability, auxiliary feedwater systems, Units 1 and 2

The inspectors reviewed operator log entries, daily shift manager reports, plant computer data, CRs, MAI paperwork, maintenance rule data, and performance indicator data sheets to determine whether the licensee adequately verified the four performance indicators listed above. This number was compared to the number reported for the performance indicator during the past 3 quarters. Also, the inspectors interviewed licensee personnel responsible for compiling the information.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors chose three issues for more in depth review to verify that licensee personnel had taken corrective actions commensurate with the significance of the issues. The issues and their bases for their selection is described below:

- The Unit 2 HPSI system had an ongoing condition of limited net positive suction head margin for the HPSI Pump C. Licensee personnel modified the system during the refueling outage performed in this inspection period to increase net positive suction head margin and other related conditions previously analyzed.
- The inspectors reviewed a degraded condition of the Unit 1 south emergency switchgear room Cooler VCH-4B on October 8, 2003. The cooler had exhibited a similar condition in August 2003 and indications of ineffective corrective action were present.

- The inspectors selected a leak from a MNSA on the bottom of the Unit 2 pressurizer to inspect. The MNSA was installed as a corrective action to eliminate leakage from pressurizer heater sleeves. Upon initial indications, the MNSA appeared ineffective at eliminating the leakage.

When evaluating the effectiveness of the licensee's corrective actions for these issues, the following attributes were considered:

- Complete and accurate identification of the problem in a timely manner commensurate with its significance and ease of discovery
- Evaluation and disposition of operability and reportability issues
- Consideration of extent of condition, generic implications, common cause, and previous occurrences
- Classification and prioritization of the resolution of the problem commensurate with its safety significance
- Identification of root and contributing causes of the problem for significant conditions adverse to quality
- Identification of corrective actions which are appropriately focused to correct the problem
- Completion of corrective actions in a timely manner commensurate with the safety significance of the issue

b. Findings and Observations

There were no findings identified with the review of the Unit 2 HPSI system actions taken to correct available net positive suction head margin.

A licensee identified violation of 10 CFR Part 50, Appendix B, Criterion V, stemming from an inadequate postmaintenance test was discovered during the review of the actions taken for a repeat failure of the Unit 1 south emergency switchgear room Cooler VCH-4B. This licensee identified violation is documented in Section 4OA7 of this report.

One Green NCV and one unresolved item (URI) were discovered in the review of the leak of one of the Unit 2 mechanical nozzle seal assemblies. These issues are discussed as follows:

MNSA Leakage

Description. In April 2002, during the Unit 2 Refueling Outage 2R15, the licensee discovered six pressurizer heater sleeves which were leaking. The licensee sought and was granted relief from the ASME pressure vessel code by the NRC Office of Nuclear Reactor Regulation (NRR) to use a second design of MNSAs on the six locations to eliminate the leakage.

The MNSAs were installed external to the pressurizer. The design consisted of machining a counterbore area around the heater sleeve of sufficient depth to allow installation of grafoil packing material. This grafoil packing material was held in place by a retaining clamp which was held in place by an assembly which supported the MNSA and was held in place by four studs which were tapped into the bottom surface of the pressurizer vessel. These MNSAs were designed to be zero leakage devices which would alleviate problems associated with leakage of borated water from the reactor coolant system via leaking pressurizer heater sleeves and concerns with pressurizer heater ejection.

On September 27, 2003, after shutdown for Refueling Outage 2R16, the licensee conducted inspections of the MNSAs as committed to in their request to NRR for use of these assemblies. Licensee personnel then discovered that the MNSA in Location C-2 exhibited evidence of leakage. Further determinations concluded that the MNSA had indeed leaked, contrary to its intended purpose. None of the other five installed MNSAs indicated leakage.

Upon disassembly of the MNSA for troubleshooting, licensee personnel discovered a small piece of metal in the counterbore area. This piece of metal extended a span of 150 degrees around the counterbore internal surface. Before removal of the grafoil seal material, it was observed to span 60 degrees around the counterbore internal surface in the area above the grafoil seal. This material was determined to be metal which was not removed from the pressurizer adjacent to the heater sleeve during the counterboring process. The inspectors determined that Procedure ER-ANO-2000-2796-008, "Instructions for Pressurizer Heater Sleeve Nozzles," Revision 8, which was used to perform the counterbore for installation of the MNSA, specified inspection of the machine counterbore and cleaning out of any debris that was discovered in Step 5.3.32, but the procedure did not specify how to conduct the visual inspection. As a result maintenance personnel conducted the inspection with human eyes unaided in any way. This inspection was unsatisfactory in that it did not account for the possibility of leaving part of the pressurizer metal in the counterbore area. Detection of this metal would be extremely difficult with the bare eyes since any metal left remaining in the counterbore area would appear shiny against a shiny background of the heater sleeve. Therefore, the licensee concluded and the inspectors concurred that the procedure for installation of the MNSA was inadequate and needed to require use of an enhanced inspection device, such as a boroscope.

The piece of remnant metal created a leakage path past the grafoil seal (between the remnant metal and the pressurizer heater sleeve), down the pressurizer heater sleeve, between the two clamshell pieces making up the compression collar, and then onto the surface of the pressurizer. The amount of leakage was small, about one cubic centimeter in size. The leakage was in contact with the carbon steel pressurizer bottom surface and was white in appearance. When the leakage was subsequently cleaned off, no wastage of the pressurizer carbon steel was evident.

Analysis. The inspectors considered this issue to be more than minor because it was analogous to Example 2.e in Appendix E of Manual Chapter 0612 because in both cases issues with procedures impacted the ability of seals to perform their function. The inspectors assumed that the amount of leakage was extremely small and no degradation to the pressurizer occurred due to boric acid corrosion. Using Phase I of the significant determination process, the inspectors determined that the finding affected the initiating events cornerstone and that it did not increase the likelihood of a fire or flooding. The finding was, therefore, characterized as Green or of very low safety significance.

Enforcement. The inspectors determined that this issue was a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that activities affecting quality be prescribed in procedures of a type appropriate to the circumstances. Contrary to this, when developing the MNSA installation procedure before April 2002, licensee personnel failed to prescribe an adequate method of inspecting the counterbore region of the MNSA prior to its installation, which led to a situation where material was left in the counterbore area allowing leakage through an unanalyzed path, allowing boric acid to be in contact with the carbon steel vessel of the pressurizer. This violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000368/2003005-03) because of the very low safety significance of this condition and because the licensee included this condition in their corrective action program in CR ANO-2-2003-1376. This CR documents ANO personnel's efforts to remove the foreign material found in the MNSA and specify a more appropriate inspection method for the counterbore region of the MNSA.

Adequacy of Design of the MNSA

As described above, during the Unit 2 Refueling Outage 2R16 in September 2003, licensee personnel performed a required inspection of the MNSAs as required by NRR in their approval of the use of the MNSAs. One of the MNSAs was determined to be leaking and was later determined to be caused by a remnant piece of metal left in the counterbore area during installation. This created a leak path which had not previously been analyzed. Regional NRC personnel were made aware of this situation and they conducted a more in depth review of the design of the MNSA and its installation on the Unit 2 pressurizer.

Their review questioned various aspects of the design of the MNSAs. All of these aspects were reviewed with licensee and MNSA vendor engineers from Westinghouse and as a result two analyses were still in need of future review by NRC personnel. First, non-conservatisms were noted in the sleeve ejection analysis. An example of this was the crediting of grafoil packing material used in the MNSA as a load bearing material. Second, the licensee and vendor had not considered the effect of the grafoil seal's radial load on the heater sleeve in their analysis. These discrepancies require further documentation from ANO personnel in order to determine the significance of the deficiencies. Also, all of these questions are potential examples of a violation of 10 CFR Part 50, Appendix B, Criterion III. The inspectors considered these issues to be an unresolved item (URI) pending further review inspection to determine the significance of the design issues (URI 05000368/2003005-04).

2. Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 2OS2 evaluated the effectiveness of the licensee's problem identification and resolution processes relating to ALARA planning and control program. No findings of significance were identified.

Section 4OA3 documents a condition where licensee personnel did not perform timely corrective action to the power switch which fed CEA 43. The untimely action led to a dropped CEA initiating event which was followed by emergency borating and eventually a reactor trip.

Section 4OA7 references a condition where the licensee did not preclude recurrence of failure of the Unit 1 south emergency switchgear room Chiller VCH-4B.

4OA3 Event Followup (71153)

(Closed) Licensee Event Report (LER) 05000368/2001002-00, An Improperly Positioned Mode Select Switch Resulted In An Automatic Actuation of The Reactor Protection System While Troubleshooting a Dropped CEA

a. Inspection Scope

The inspectors reviewed the LER and corrective action documents CR ANO-2-2001-0297, CR ANO-2-2001-0611, and CR ANO-2-2001-1115, which documented this event and the circumstances which led to it, to verify that the cause of the November 1, 2001, Unit 2 reactor trip event was identified and that corrective actions were reasonable. The reactor trip was caused by an operator who made a switch manipulation error while performing a postmaintenance test in response to a dropped CEA. The inspectors reviewed plant parameters and verified that licensee staff properly implemented the appropriate plant procedures and that plant equipment performed as required. The inspectors also reviewed the cause of the sequence of events dating back to the original signs of equipment problems.

b. Findings

Operator Error Causes a Reactor Trip During Control Element Assembly

Postmaintenance Testing

Introduction. A Green noncited violation of 10 CFR Part 50, Appendix B, Criterion V, revealed itself when a Unit 2 operator mispositioned the control element drive mechanism control system (CEDMCS) mode select switch during a CEA retest resulting in a reactor trip.

Description. At 10:10 a.m. on November 1, 2001, during normal power operations of Unit 2 at 100 percent power, CEA 43 dropped from its fully withdrawn position fully into the core. The licensee took actions for the dropped CEA and eventually lowered reactor power to approximately 24 percent and began efforts to identify the cause and correct it. Later that day, the licensee determined that the cause of the dropped CEA was a faulty power switch. The licensee replaced the power switch and began a postmaintenance test of the system with a replaced component.

The retest was performed in accordance with MAI 45437 and consisted of manually stroking the CEA's in that CEA subgroup to verify their proper operation. Accomplishment of individually stroking a CEA was prescribed in Procedure 2105.009, "CEDM Control System Operation," Revision 21, Step 11.2.3, which required the CEDMCS mode selector switch to be selected in the "manual individual" position so that only that particular CEA selected would be manipulated.

During the retest, CEA 43 was withdrawn to 4 inches. In this step, the CEDMCS mode selector switch was positioned to "manual individual," CEA 43 was withdrawn, and the CEDMCS mode selector switch was then returned to the "off" position to preclude any undesired rod motion. The next step in troubleshooting was to insert CEA 43. The reactor operator then positioned the CEDMCS mode selector switch to the "manual group" position, in error, instead of positioning it to the "manual individual" position as prescribed by procedure. As a result, all eight of regulating Group 1 CEAs (four from Subgroup 10 and four from Subgroup 11) were inserted while the reactor operator believed he was only inserting solely CEA 43. The operator did not notice this in his monitoring of rod positions because he was focused on a single indication of rod position and not on diverse indications. Also, he was not peer checked by another licensed operator to ensure that he had properly manipulated the CEA mode selector switch.

Inward CEA motion was continued by the reactor operator until CEA 43 reached its lower electrical limit of full insertion. This caused the other three CEA's in Subgroup 11 to stop. The reactor operator at that time did not realize CEA 43 had reached the bottom of the core and continue to give an insert command on the CEA control switch which continued to insert the four CEAs in Subgroup 10. Insertion of Subgroup 10 continued until the subgroup of CEAs were inserted to approximately 138 inches at which time a subgroup deviation resulted and the core protection calculator generated a penalty factor from planar radial peaking for its departure from nucleate boiling ratio and local power density calculations resulting in a reactor trip signal being sent to the reactor protection system. This caused a reactor trip.

Analysis. The inspectors determined that this finding affected the initiating events cornerstone and was more than minor because it was analogous to Example 4.b in Appendix E of Manual Chapter 0612 because an operator error caused a reactor trip. In determining the significance of this finding, the inspectors assumed that no other complicating events were caused by the error, all mitigating systems remained available to the operators, the finding did not increase the likelihood of a fire or flooding and, therefore, determined the finding was Green or of very low safety significance.

Enforcement. The inspectors determined that the improper manipulation of the CEDMCS mode selector switch was a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that activities affecting quality shall be accomplished in accordance with prescribed procedures. Contrary to the above, on November 1, 2001, during the retest of CEA 43, Unit 2 operators did not accomplish the movement of only CEA 43 in accordance with Procedure 2105.009, "CEDM Control System Operation," Revision 21. Because of the very low safety significance of this condition and because the licensee included this condition in their corrective action program in CR ANO-2-2001-1115, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000368/2003005-05). This CR documents licensee personnel's efforts to upgrade the operating crews deficiencies as well as steps enacted to prevent recurrence of similar events.

Failure to Promptly Correct a Faulty Power Supply Switch Leads to a Dropped Control Element Assembly at Power

Introduction. A Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, revealed itself when licensee personnel failed to promptly correct a faulty optical isolator card in the power supply switch for the Unit 2 CEA regulating Group 1 resulting in a dropped rod and unplanned power transient.

Description. On April 20, 2001, abnormal traces were noted on CEA 43 during the performance of planned quarterly Unit 2 CEA exercise testing. The traces record the currents through each of five CEA mechanism coils when each CEA is stepped. The abnormal traces were indicative of a missing phase on the lift coil and an intermittently missing phase on the upper grip coil. At that time, the cause of the missing phases on CEA 43 was determined to be subcomponents internal to the power switch for Subgroup 11, with speculation that faulty silicon controlled rectifiers or defective optical isolators being the failed subcomponents. CEA 43 hold function was then transferred to the lower grip coil to prevent degradation of the upper grip coil.

Repair or replacement of the power switch for Subgroup 11 was considered by licensee personnel. Repair to the power switch would have required postmaintenance testing of all four CEAs powered by the power switch. Also, repair would have required movement and proper replacement of the heavy and cumbersome power switch which hooked into a very fragile back plane connector panel would have been necessary, and exposure to the consequences of a personnel error during the maintenance which could have led to a dropped CEA or reactor trip. Licensee management weighed the intrusive nature of that maintenance against the presumptive safe operation on the lower grip coil and decided to wait until the next available outage to repair the power switch.

On July 27, 2001, while performing the next scheduled quarterly CEA exercise test, when operators were inserting CEA 43 into the core, it dropped fully into the core when its power supply breaker opened. Troubleshooting consisted of closing the breaker for CEA 43, fully withdrawing it from the core, transferring it to the lower grip coil, and recording traces. These traces revealed that the lift coil still had a missing phase and the upper grip coil now had a continuously missing phase. The cause of the dropping of CEA 43 was a trip of the CEA 43 breaker caused by increased current from the lift and upper grip coils which was elevated by the missing phases. No other abnormalities in the traces were noted.

Licensee personnel decided to again transfer the hold function to the lower grip coil and wait until the next available outage to repair the power switch. This decision was made with the information from their previous decision in April 2001 to continue to operate with abnormal trace data, but was informed with the knowledge that missing phases are common problems to the type of rod control system used in Unit 2 and these malfunctions had minimal impact on operation of the system. The licensee sought and received a technical specification change from NRR to relax the requirement to perform quarterly CEA testing on CEA 43 since movement of the CEA would most likely lead to its dropping into the core. Licensee personnel were convinced that the problem was just with the upper grip and lift coils, and that if the licensee did not have to move the CEA, the licensee could operate satisfactorily until the next outage and then repair the Subgroup 11 power supply switch.

Uncomplicated CEA 43 operation continued until November 1, 2001, when CEA 43 (fully withdrawn and not moving) dropped fully into the core. The event caused an unexpected reactor transient dropping power immediately by approximately 4 percent. Subsequently, Unit 2 operators reacted by reducing reactor power to approximately 78 percent in accordance with Procedure 2203.003, "CEA Malfunction," Revision 15. Troubleshooting efforts determined that lift coil now had a continuously firing phase, the upper grip coil still had its missing phase, and now the lower grip coil had a missing phase. The CEA 43 breaker had tripped due to the high current from the continuously firing lift coil phase combined with the increased current from the missing phase from the lower grip coil. The Subgroup 11 power supply switch was then repaired and the cause of the dropping of CEA 43 was determined to be degradation of the optical isolator circuit.

The degraded optical isolator circuit which caused the missing phases was the cause in the events described above. Its failure started out exhibiting abnormal traces during CEA exercise testing, went on to causing the CEA to drop when movement was attempted, and eventually spread to causing the CEA to drop due to the degradation affecting the lower grip coil. The licensee rationalized, with risk arguments, that the least risky course of action was to defer repair or replacement of the Subgroup 11 power switch until the next shutdown. The inspectors noted that procedure LI-102, “Corrective Action Process,” Rev. 1, called out the highest severity level for condition reports as involving a significant loss of production that occurred, or reasonably could occur. A condition considered significant under the corrective action process would require a root cause analysis. LI-102 also stated that a root cause analysis was used for complex issues or those where the cause is not understood or readily known. Licensee personnel did not perform a root cause analysis to determine the possible causes of the missed phases in the affected coils, but proceeded based upon their assumptions of likely causes. By not repairing the power switch for Subgroup 11 or determining what was causing the missing phases, the licensee allowed the conditions to degrade until CEA 43 dropped while stationary, thereby, initiating an unplanned twenty-two percent transient .

Analysis. The inspectors determined that this finding, which affected the initiating events cornerstone objective of limiting the likelihood of those events that upset plant stability during power operations, was more than minor and attributable to poor equipment performance from untimely maintenance. In determining the significance of this finding, the inspectors assumed there were no other complicating factors, CEA 43 was always capable of performing its safety function, and the finding did not increase the likelihood of a fire or flooding; and therefore, determined the finding was Green or of very low safety significance.

Enforcement. The inspectors determined that the failure to identify and correct the faulty optical isolator card in the power switch for the regulating Group 1 CEA was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, which requires that measures shall be established to assure conditions adverse to quality, such as malfunctions, are promptly identified and corrected. Contrary to the above, between July 27, 2001, and November 1, 2001, Unit 2 licensee personnel did not promptly identify and correct the malfunctioning power switch which supplied CEA 43, thereby, leading to CEA 43 dropping fully into the core a second time. Because of the very low safety significance of this condition and because the licensee included this condition in their corrective action program in CR ANO-2-2001-0611, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000368/2003005-06). This CR documents licensee personnel's efforts to identify the cause and improve procedural steps to prevent recurrence.

4OA5 Other Activities

Preoperational Testing of an Independent Spent Fuel Storage Installation (60854) and Review of 10 CFR 72.212(b) Evaluations (60856)

a. Inspection Scope

An NRC inspection of selected preoperational testing activities related to use of the Holtec HI-STORM 100 cask system at the ANO independent spent fuel storage installation (ISFSI) was conducted on November 18-20, 2003. ANO had completed loading 24 Sierra Nuclear Casks VSC-24s preparing for the next loading campaign using the Holtec HI-STORM 100 cask system. The first Holtec cask was scheduled for loading during December 2003.

License Conditions 10.a through 10.j of the Holtec Certificate of Compliance 1014 required preoperational testing prior to the first use of the HI-STORM 100 cask system. ANO completed all the requirements in License Condition 10 by demonstrating the use of the Holtec systems during NRC inspections on March 17-20 and April 21-24, 2003, and this inspection and by demonstrations observed by the NRC during the preoperational inspections on the Sierra Nuclear casks. Inspection Report 05000313/1996016; 05000368/1996016; 07200013/1996001 dated July 31, 1996, and Inspection Report 05000313/2003003; 05000368/2003003; 07200013/2003002 dated September 8, 2003, provide documentation of the previously demonstrated activities. The following list provides a summary of the completed demonstrations as required by Licensee Condition 10.

10.a Moving the canister and transfer cask into the spent fuel pool (observed in NRC Inspection Report 07200013/1996001).

10.b Preparation of cask for fuel loading (observed in NRC Inspection Report 07200013/1996001).

10.c Selection and verification of specific fuel assemblies to ensure type conformance (Document 1302.028, "Fuel Selection Criteria for Dry Storage," was reviewed during this inspection. This document provided a description of the fuel selection criteria being used by ANO and was consistent with the Technical Specification requirements specified in the Holtec Certificate of Compliance 72-1014).

10.d Loading specific assemblies into the canister, using a dummy fuel assembly, including independent verification (observed in NRC Inspection Report 07200013/1996001).

10.e Remote installation of the canister lid and removal of the canister and transfer cask from the spent fuel pool (observed in NRC Inspection Report 07200013/1996001).

10.f Canister welding, nondestructive examinations, hydrostatic testing, draining, moisture removal by vacuum drying or forced helium dehydration, helium backfilling, and leakage testing (observed in NRC Inspection Report 07200013/2003002).

10.g Transfer cask upending and downending. (Not applicable to ANO. All cask handling operations are performed in the vertical position with no upending or downending operations.)

10.h Transfer of the canister from the transfer cask to the overpack (observed during this inspection).

10.i Placement of a cask at the ISFSI (observed during this inspection).

10.j Cask unloading, including cooling fuel assemblies, flooding canister cavity and removing canister lid welds. (Cask unloading was observed during this inspection. All other activities were observed in NRC Inspection Reports 07200013/2003002 and 07200013/1996001.)

ANO's preoperational demonstrations were performed using a work plan that had been written, tested, revised, and approved to support the evolution. All personnel knew their duties and carried them out efficiently. The activities observed during this inspection complete the NRC's preoperational inspection program requirements for the use of the Holtec HI-STORM 100 cask system at ANO.

In addition to observing the final preoperational demonstrations for the Holtec HI-STORM 100 cask system, the NRC reviewed several issues related to the concrete ISFSI pad, the Ederer crane and completed the review of the licensee's 10 CFR 72.212 evaluation. The ISFSI pad for storage of the Holtec casks had been constructed adjacent to the concrete pad storing the Sierra Nuclear casks. The Holtec Final Safety Analysis Report, Table 2.2.9, and Section 3.4.7.1, required the surface of the ISFSI pad used for storing the Holtec casks to have a coefficient of friction greater than 0.53. The licensee had completed the ISFSI pad coefficient of friction testing in April 2003 with all data points indicating greater than 0.53. During this inspection, the NRC inspectors requested a demonstration of the testing that had been performed in April. The demonstration yielded coefficient of friction values consistently 20-25 percent lower than the previous measurements, with some values below the 0.53 requirement. CR ANO-C-2003-00983 was generated by the licensee to evaluate this discrepancy. On December 12, 2003, the licensee took several coefficient of friction readings in two locations at the far north end of the ISFSI pad. One of these two locations will be the resting place for the first Holtec cask. The weather was cool and dry and the ISFSI pad surface was blown dry with service air. All sample locations indicated a coefficient of friction greater than 0.53.

CR ANO-C-2003-00989 was generated to evaluate calcium deposits that were observed around the air inlets on several new Holtec HI-STORM casks that were in storage on the ISFSI pad. The licensee contacted Holtec via e-mail on November 19, 2003, and requested a determination of the significance of the deposits and a recommended corrective action. Holtec responded indicating that the deposits were efflorescense (leaching of lime) and were only important in so far as they mar the appearance of the cask. Holtec recommended cleaning these areas and applying touch up paint to any rusted areas. The affected areas on the first cask to be loaded were cleaned. No rust was present and no touch up paint was applied.

During the 125 percent load test conducted on the new Ederer crane in January 2003, the NRC had identified a discrepancy between the test acceptance criteria in the ANO procedures versus the acceptance criteria specified by Ederer, the crane manufacturer. This issue was documented as an inspector followup item (IFI) in NRC Inspection Report 05000313/2003009; 05000368/2003009; 07200013/2003001 dated February 7, 2003. The licensee also opened CR ANO-1-2003-00364 concerning the issue. On June 2, 2003, Ederer issued a letter to ANO stating that the 125 percent load test acceptance criteria used by ANO met the ASME B30.2 1997 criteria and was acceptable to Ederer. This closes the open item (IFI 07200013/2003001-01).

The 10 CFR 72.212(b) evaluation for the use of the Holtec casks at the ANO site was reviewed. The evaluation encompassed the environmental conditions at ANO and identified the licensee’s programs that were revised to incorporate the use the Holtec HI-STORM 100 cask system at ANO. No discrepancies or issues were identified.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On October 8, 2003, the inspectors presented the results of the inservice inspection effort to Mr. C. Eubanks, General Manager, Plant Operations, and other members of licensee management. Licensee management acknowledged the inspection findings.

On October 10, 2003, the inspector presented the inspection results for the review of the ALARA planning and controls program to Mr. C. Eubanks, General Manager, Plant Operations, and other members of his staff who acknowledged the findings.

On November 20, 2003, the inspectors presented the inspection results of the ISFSI inspection to Mr. R. Lingle, Plant Manager, Operations, and other members of the licensee's management staff who acknowledged the findings.

On January 7, 2004, 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. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Several documents were proprietary information as identified by the licensee. The inspectors noted that while proprietary information was reviewed, none would be included in this report.

40A7 Licensee-identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- 10 CFR Part 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances. On October 8, 2003, during a monthly surveillance run, the Unit 1 south emergency switchgear room Chiller VCH-4B was determined to be degraded due to an inadequate postmaintenance test procedure following the initial repair following a previous similar failure on August 12, 2003. This condition is described in the licensee's corrective action program in CRs ANO-1-2003-0868 and ANO-1-2003-1030. Because with compensatory measures, the remaining room cooling capability was sufficient to maintain the components in the switchgear room within the licensee's room heatup analysis, this violation is not more than of very low safety significance, and is being treated as an NCV.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Ashley, Manager, Licensing
R. Beaird, Supervisor, Systems Engineering
S. Bennett, Licensing Specialist
L. Compton, Manager, Engineering Programs and Components
S. Cotton, Director, Nuclear Safety Assurance
J. Forbes, Vice President, Operations
F. Forrest, Unit 1 Operations Manager
D. Fronabarger, Acting Superintendent, Instrumentation and Control
C. Eubanks, General Manager, Plant Operations
R. Gordon, Manager, Planning and Scheduling
D. Hawkins, Licensing Specialist
A. Heflin, Unit 2 Operations Manager
J. Hoffpauir, Manager, Maintenance
R. Holeyfield, Manager, Emergency Planning
B. James, Manager, Alloy 600 Project
D. James, Manager, Corrective Actions and Assessments
J. Kowalewski, Director, Engineering
R. Lingle, Plant Manager, Operations
J. Miller, Manager, Training
T. Mitchell, Technical Assistant
K. Nichols, Manager, Design Engineering
R. Partridge, Superintendent, Chemistry
B. Patrick, Manager, Radiation Protection
S. Pyle, Licensing Specialist
D. Scheide, Licensing Specialist
W. Sims, Supervisor, Design Engineering
C. Tyrone, Manager, Quality Assurance
C. Zimmerman, Plant Manager, Support

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000368/2003005-04	URI	Design Deficiencies with MNSAs (Section 4OA2)

Opened and Closed

05000368/2003005-01	NCV	Failure to Properly Install a HPSI System Flow Transmitter (Section 1R22)

05000368/2003005-02	NCV	Three Examples of Failure to Perform Radiological Surveys (Section 2OS2)
05000368/2003005-03	NCV	Inadequate Procedure for MNSA Installation Leading to a Reactor Coolant System Leak (Section 4OA2)
05000368/2003005-05	NCV	Operator Error Causes a Reactor Trip During CEA Postmaintenance Testing (Section 4OA3)
05000368/2003005-06	NCV	Failure to Promptly Correct a Faulty Power Supply Switch Leads to a Dropped CEA at Power (Section 4OA3)

Closed

05000368/2001002-00	LER	An Improperly Positioned Mode Select Switch Resulted In an Automatic Actuation of the Reactor Protection System While Troubleshooting a Dropped CEA (Section 4OA3)
72-13/2003001-01	IFI	Acceptance Criteria for Test Load Weights for the 125 percent L3 Crane Tests (Section 4OA5)

Discussed

NONE

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out 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 1R08: Inservice Inspection (71111.08)

	TITLE	REVISION/CHANGE
5120.243	Unit 2 - Post Outage Pressure Test	008-01-0
CEP-PT-001	ASME Section XI, Division 1, System Pressure Testing	0
1415.038	Manual Ultrasonic Examination of Pressure Vessel Welds	007-00-0
NDE9.19	Ultrasonic Instrument Linearity Verification	3

PROCEDURES (Wesdyne)	TITLE	REVISION/CHANGE
WDI-TJ-006-03-P	Ultrasonic Testing of Interference Fit Samples for Leak Path Detection	2
WDI-TJ-012-03-P	Triple Point Inspection Using TOFD Ultrasonic Methods	2
WDI-TJ-001-02-P	Detection of Reactor Head Base Metal Loss from Inside the CRDM Penetration	3

CRs

ANO-2-2003-01216
ANO-2-2003-01248
ANO-2-2003-01376
ANO-2-2003-01416
ANO-2-2003-01464

Weld Repair/Replacement Package

02-2068
01-2230
02-2029
03-0295
03-2053
03-2074

Visual Examinations (ISI Exam)

24-069
52-039
88-001

Radiographic Examination Report

203RT006
203RT007
203RT008
203RT009
203RT010

Liquid Penetrant Examination Reports (ICI Nozzles)

203SIIPT005
203SIIPT006
203SIIPT007
203SIIPT008
203SIIPT009
203SIIPT010

Calibration Data Sheet

203ISIUT007
203ISIUT008
203ISIUT011
203ISIUT012

Section 2OS2: ALARA Planning and Controls (71121.02)

Corporate Procedures

RP-105, RWPs, Revision 4
RP-109, Hot Spot Program, Revision 0
RP-110, ALARA Program, Revision 1
RP-201, Dosimetry Administration, Revision 1
RP-205, Prenatal Monitoring, Revision 2
RP-503, Selection, Issue, and Use of Respiratory Protection Equipment, Revision 0
RP-504, Breathing Air, Revision 0

Arkansas Nuclear One Site Procedures

1601.003, Control of Temporary Shielding, Change 008-00-0
1601.200, Personnel Processing Records, Change 008-01-0

Temporary Shielding Records (TSR)

TSR 03-2-027, Regenerative Heat Exchanger to 2RC-5A/R2 South Cavity
TSR 03-2-043, Regenerative Heat Exchanger / R2 South Cavity 354
TSR 03-2-050, Shutdown Cooling Piping / R2 354
TSR 03-2-060, Bottom of the Pressurizer
TSR 03-2-077, 2CVC-27 Piping for 2CVC-1186 & 2CVC-1187 Valve Replacement

Unit 1 Long Term Shielding Records

TSR 02-1-017, A-1-354 Sample Preparation Hood
TSR 02-1-019, A-1-360 UNPPR Piping Between CV-1221 and RE-1237

Unit 2 Long Term Shielding Records

TSR 02-2-001, A-2-317 Auxiliary Building Sump
TSR 02-2-005, A-2-335-2P-36B Piping 2HCB-45-2 / 2HCB-43-3

RWP Packages

RWP 2003-2413, ALARA Shielding and Source Reduction Activities
RWP 2003-2435, Remove/Replace Reactor Vessel Internals
RWP 2003-2441, Cut-up and Remove Incore Detectors from the Refueling Canal
RWP 2003-2452, Reactor Head Nozzle Inspection
RWP 2003-2466, Pressurizer Heater Nozzle Inspection and Repair

Hot Spot Posting Verification

HS-1-007, HS-1-020, HS-1-025, HS-1-029, HS-2-001, and HS-2-010

ALARA Managers Committee Meeting Minutes

ANO-2003-0029, April 11, 2003; ANO-2003-0041, April 30, 2003; ANO-2003-0060, May 9, 2003; ANO-2003-0076, June 17, 2003; ANO-2003-0088, July 22, 2003; ANO-2003-0095, August 6, 2003; ANO-2003-0097, August 22, 2003

ALARA Sub-Committee meeting Minutes

February 27, 2003; March 27, 2003; April 8, 2003; April 24, 2003; May 29, 2003; June 26, 2003; July 31, 2003; and August 29, 2003

ALARA CRs

Unit 1

ANO-1-2003-00960

Unit 2

ANO-2-2003-00197, 2003-00343, 2003-00589, 2003-01130, 2003-01240, 2003-01365, 2003-01473, and 2003-01501

Common

ANO-C-2003-00031, 2003-00066, 2003-00108, 2003-00209, 2003-00210, 2003-00211, 2003-00258, 2003-00259, 2003-00431, 2003-00439, 2003-00480, 2003-00683, 2003-00687, 2003-00849, 2003-00850, and 2003-00851

Echelon

CR-ECH-2003-00015 and 2003-00050

Section 4OA2: Problem Identification and Resolution (71152)

All Unit 1 CRs numbered ANO-1-2003-0987 through ANO-1-2003-1275
All Unit 2 CRs numbered ANO-2-2003-1263 through ANO-2-2003-1946
All Common ANO CRs numbered ANO-C-2003-0793 through ANO-C-2003-1097

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
ANO	Arkansas Nuclear One
ASME	American Society of Mechanical Engineers
CEDMCS	control element drive mechanism control system
CFR	*Code of Federal Regulations*
CR	condition report
ECP	emergency cooling pond
EDG	emergency diesel generator
HPSI	high pressure safety injection
ICI	incore instrumentation
ISFSI	independent spent fuel storage installation
LER	licensee event report
MAI	maintenance action item
MNSA	mechanical nozzle seal assembly
NCV	noncited violation
NDE	nondestructive examination
NRR	Office of Nuclear Reactor Regulation
RPV	reactor pressure vessel
RWP	radiation work permit
SG	steam generator
SSC	structure, system, or components
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item