May 9, 2003

Mr. M. Bezilla
Vice President
FirstEnergy Nuclear Operating Company
Post Office Box 4
Shippingport, Pennsylvania 15077

SUBJECT: BEAVER VALLEY POWER STATION - NRC INTEGRATED INSPECTION REPORT 50-334/03-02, 50-412/03-02

Dear Mr. Bezilla:

On March 29, 2003, the Nuclear Regulatory Commission (NRC) completed an inspection at your Beaver Valley Units 1 and 2. The enclosed report documents the inspection findings which were discussed with you and members of your staff during an exit meeting on April 3, 2003.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection involved examination of selected procedures and representative records, observation of activities, and interviews with personnel.

Based on the results of this inspection, the inspectors identified three issues of very low safety significance (Green). The issues were determined to involve violations of NRC requirements. However, because of the low safety significance and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited violations, in accordance with Section VI-A of the NRC's Enforcement Policy. If you deny the Non-Cited violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspectors at the Beaver Valley facility.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders (dated February 25, 2002, January 7, 2003 and three dated April 29, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction (TI) 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25 Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY '03, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm.html (the Public Electronic Reading Room).

We appreciate your cooperation. Please contact me at 610 337-5225 if you have any questions regarding this letter.

Sincerely,

/RA/

Neil S. Perry, Chief
Projects Branch 7
Division of Reactor Projects

Docket Nos.: 50-334, 50-412
License Nos: DPR-66, NPF-73

Enclosure: Inspection Report 50-334/03-02; 50-412/03-02
w/Attachment: Supplemental Information

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REGION I

Docket Nos.	50-334, 50-412
License Nos.	DPR-66, NPF-73
Report Nos.	50-334/03-02, 50-412/03-02
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	December 29, 2002 - March 29, 2003
Inspectors:	D. Kern, Senior Resident Inspector G. Smith, Resident Inspector J. McFadden, Health Physicist D. Silk, Senior Emergency Preparedness Engineer M. Modes, Senior Reactor Engineer H. Gray, Senior Reactor Engineer R. Barkley, Senior Project Engineer
Approved by:	N. Perry, Chief Projects Branch 7 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000334/03-02, IR 05000412/03-02; FirstEnergy Nuclear Operating Company; on December 29 - March 29, 2003; Beaver Valley Power Station (BVPS), Units 1 and 2. Maintenance Rule Implementation, Personnel Performance During Non-Routine Plant Evolutions, and Event Follow-up.

The inspection was conducted by resident inspectors, a regional health physics inspector, regional security specialist, regional inservice inspection (ISI) specialists, and regional projects inspectors. The inspection identified four Green findings which were non-cited violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after Nuclear Regulatory Commission (NRC) management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Rev. 3, dated July 2000.

A. Inspector Identified Findings

Cornerstone: Initiating Events

- Green. Ineffective corrective actions to address degraded instrument air system performance resulted in a Unit 2 loss of instrument air (LOIA) pressure event on March 8, 2003. Specifically, corrective and preventive maintenance (PM) activities were not performed as specified in work orders and station procedures.

  The finding was an NCV of 10 Code of Federal Regulations (CFR) 50.65(a)(1) for failure to take appropriate corrective action for a maintenance rule scope system which did not meet its category (a)(1) performance goals. The finding was of very low safety significance because operator action recovered instrument air pressure in time to avoid a plant transient and mitigation equipment was not affected (Section 1R12).

- Green. Human performance errors during preparation of a ground fault relay setpoint modification caused an inadvertent deenergization of the Unit 1 'D' 4.16 kilovolt (kV) switchgear. The event resulted in a partial loss of feedwater transient, brief deenergization of the 'DF' emergency 4.16 kV switchgear, and auto start of the 1-1 emergency diesel generator (EDG). The modification lowered the relay setpoint from 200 amperes to 120 amperes without adequately evaluating sensor error or motor starting current for large loads on the bus. The existing ground fault current error was not measured nor accounted for in development of the test procedure which could have prevented the loss of the 'D' bus and subsequent unplanned plant transient.

  The finding was an NCV of 10 CFR 50, Appendix B, Criterion XI "Test Control" for failure to address and test the effect the modified relay setpoint had on normal 'D' 4.16 kV electrical bus operation. The finding increased the likelihood of an initiating event, but remained of very low safety significance because alternate power supplies remained available (Section 1R14).

- <u>Green</u>. Failure to properly preplan and control maintenance activities (scaffold erection) in the vicinity of the ‘C’ main steam isolation valve (MSIV) actuator led to an unplanned Unit 1 safety injection (SI) actuation and reactor trip on February 24, 2003. Procedure BVSG-002, “Scaffold Erection and Tagging,” Rev. 3, required an operations department review and approval of the scaffold erection activity. The review for this activity failed to identify precautions to protect safety-related equipment such as the MSIV actuator rupture disk. This represented human performance errors in both the pre-evolution risk review and the scaffold erection activity.

  This finding was an NCV of Technical Specification (TS) 6.8.1 and was of very low safety significance because the issue did not affect the availability of mitigation equipment (Section 4OA3.1).

B. <u>Licensee Identified Violations</u>

A violation of very low significance 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 corrective action tracking number is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On February 24, an automatic SI actuation and reactor trip occurred due to low main steam line pressure. This was caused by human error when a scaffold erection crew damaged the ‘C’ MSIV actuator, causing the MSIV to fail shut (Section 4OA3). Following repairs, operators restarted the unit and synchronized to the offsite power distribution grid on February 27. During power ascension later that day, the unit experienced a loss of the ‘D’ 4.16 kV electrical bus when attempting to start the second main feedwater(MFW) pump. Power was promptly reduced from 57 to 45 percent powers in response to this transient (Section 1R14). Operators stabilized the plant at approximately 39 percent power. On March 1, operators raised power and stabilized at 55 percent until the planned refueling outage began on March 8 (Section 1R20). At the close of the inspection period, there was no fuel in the reactor vessel. The fuel was in the spent fuel pool as part of the planned outage activities.

Unit 2 operated at 100 percent power throughout the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed the station’s cold weather protection adequacy in accordance with the following operational surveillance tests (OSTs):

- 1OST-45.11 Cold Weather Protection Verification, Rev. 15
- 2OST-45.11 Cold Weather Protection Verification, Rev. 14

The inspectors reviewed the outstanding work deficiencies noted in the cold weather protection OSTs and verified that they were of minor significance and properly captured in the corrective maintenance program. The inspectors performed a walkdown of various Unit 1 and 2 safety-related heat tracing control panels and heat trace for the exposed piping that supplies safety-related systems. The inspectors reviewed recent industry cold weather issues affecting EDG and auxiliary feedwater (AFW) pump operability for applicability at BVPS. Additionally, the inspectors reviewed cold weather related condition reports (CRs) and resolution for equipment which was adversely affected by cold weather (CRs 03-0878 and 03-0881).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments

.1 Unit 1 Emergency Direct Current Power System Complete Alignment Verification

a. Inspection Scope

The inspectors conducted a complete alignment verification of the Unit 1 emergency direct current power system. This system is a risk important mitigating system which provides a back up power source to the 120 volt alternating current (Vac) vital buses, control power to the emergency 4160 Vac and 480 Vac feeder breakers, and power for other safety functions. The inspectors reviewed operating manual (OM) figures associated with the system as well as the normal system alignment checklist (1OM-39.3C, "Power Supply and Control Switch List," Rev. 3) to determine proper system alignment. In addition, the inspectors reviewed and evaluated the potential impact on the emergency direct current power system operation from open work orders (WOs), design modifications, engineering memoranda, and corrective action program CRs. The system health reports were reviewed and open issues were discussed with the system engineer.

b. Findings

No findings of significance were identified.

.2 Partial Equipment Alignments

a. Inspection Scope

The inspectors performed partial system walkdowns of the Unit 2 systems listed below to verify proper equipment alignments as required by station procedures, drawings, and technical specifications (TSs) when applicable. In addition, the inspectors evaluated the impact on system operation from the open WOs, design change packages, engineering evaluations, and corrective action program CRs.

- The inspectors verified the Unit 2 'A' train high head safety injection (HHSI) system was properly aligned in accordance with TS 3.5.2. The 'A' train high head SI system was selected due to the extended maintenance recently performed on the Unit 2 'A' charging pump as well as its high risk significance.

- The inspectors verified the Unit 2 'B' train quench spray (QS) system was properly aligned in accordance with 2OM-13.3B.1, "2QSS Valve List," Rev.7. The 'B' train QS system was selected due to the fact that the 'A' QS train was out of service for the performance of the surveillance 2OST-13.1, "Quench Spray Pump [2QSS*P21A] Test," Rev. 19, during the walkdown. The QS system was also selected since it is a high risk system.

- The inspectors performed a partial walkdown of the Unit 2 instrument air system. System alignment was verified in accordance with the following procedures/drawings: OM Figures 34-1A, 34-1B, 34-2, 34-3, and 34-4, "Station

Service and Instrument Air;" 2OM-34.3.A, “Compressed Air Systems Normal System Arrangement,” Rev. 6; 2OM-34.3.B.1, “Valve List - 2 Station Air System,” Rev. 14; 2OM-34.3.B.3, “Valve List - 2 Instrument Air System,” Rev. 10; and 2OM-34.3.C, “Power Supply and Control Switch List,” Rev. 8. The system was selected due to the ongoing maintenance of ‘B’ station air compressor as well as the relative risk importance of the system.

- The inspectors performed a partial system walkdown of the Unit 2 service water (SW) system train ‘B’ while elements of train ‘A’ were declared inoperable due to degraded fire/flood barriers between the trains. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) section that discussed SW system design, and piping and instrument drawings OM Figures 30-1 through 30-4, “Service Water System,” Rev. 24, to determine proper equipment alignment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors reviewed the Unit 1 Updated Fire Protection Appendix ‘R’ Review, Rev. 22, and the Unit 2 Fire Protection Safe Shutdown Report, Addendum 21, and identified the following risk significant areas:

- Unit 1 Cable Spreading Room (Fire Area CS-1)
- Unit 1 Primary Auxiliary Building 735' Elevation (Fire Area PA-1E)
- Unit 1 Turbine Building General Area (Fire Area TB-1)
- Unit 1 Control Room (CR-1)
- Unit 1 Primary Reactor Containment (RC-1)
- Unit 1 Plant Auxiliary Building Outage Staging Area
- Unit 2 Cable Tunnel (Fire Area CT-1)
- Unit 2 AE Emergency Switchgear Room (Fire Area SB-1)

The inspectors reviewed the fire protection conditions of the above listed areas in accordance with the criteria delineated in Nuclear Power Administrative Manual, 1/2-ADM-1900, “Fire Protection,” Rev. 2. Control of transient combustibles, material condition of fire protection equipment, and the adequacy of any fire protection impairments and compensatory measures were included in these plant specific reviews.

Additionally, the inspectors performed plant Walkdowns to verify onsite hazardous materials, including potential explosion hazards, were properly evaluated and stored in accordance with plant design basis information. Potential challenges to safety-related equipment, offsite power supplies, and risk significant components were evaluated. This review included performance of NRC Temporary Instruction (TI) 2515/146, “Hydrogen Storage Locations,” Rev. 1. Areas inspected included:

- All of Unit 1 including all outdoor areas inside of the protected area perimeter
- All of Unit 2

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed the Unit 2 UFSAR and the Probabilistic Risk Assessment Individual Plant Examination to evaluate the design basis and risk significance for internal floods. The inspectors also reviewed the TSs, abnormal operating procedure 1/2OM-53C.4A.75.2, “Acts of Nature - Flood,” Rev. 15, and operating logs to verify procedures and operator actions for coping with floods were appropriate. Based on associated risk significance, the inspectors performed walkdowns of the plant areas listed below. During these walkdowns the inspectors examined a sample of internal flood seals, inspected the material condition of potential sources of internal flooding, and verified various floor drains, sump pumps, and level alarm circuits were operable. The inspectors compared their inspection results with the most recently completed Beaver Valley Test (BVT), 2BVT-1.33.07, “Flood Seals Visual Inspection,” Rev. 1, and discussed observations with the Flood Protection Engineer. CRs or maintenance work requests were written when appropriate to resolve the inspectors’ observations. Based on reviewing recently issued CRs, the inspectors determined that station personnel maintained a low threshold for identifying and resolving flood protection issues through the CR program.

- Unit 2 safeguards building (flood zones SG-1N and SG-1S).
- Unit 2 cable tunnel (flood zone CV-1).

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection

.1 Steam Generator Inspection

a. Inspection Scope

In order to evaluate the general implementation of the steam generator program, the inspectors reviewed elements of the steam generator aging management and assessment program including: data management; degradation assessment; and plugging criteria. The inspectors reviewed the licensee’s implementation of the alternate repair criteria and discussed with the licensee the manner by which mixed residual signals were resolved.

To evaluate the specific implementation of the steam generator program, the inspectors interviewed the independent resolution analysts, and reviewed selected samples of the eddy current data acquisition and analysis of the ‘A,’ ‘B,’ and ‘C’ steam generators. For example, the inspectors reviewed the resolution results of the eddy current inspection of row 17, column 29 of the ‘B’ steam generator, and the plus-point inspection of row 30, column 20 of the cold leg of the ‘C’ steam generator.

The inspectors reviewed the visual inspection, by remote video, of the secondary side of the ‘A’ steam generator. The inspectors reviewed the remote video inspection of the separated blow down support and discussed the analytical actions taken to determine the root cause for the separation and the basis for continued operation (BCO) of the steam generator.

The inspectors also reviewed other portions of the ISI and nondestructive evaluation programs. The inspectors reviewed radiographs of welds SI-60-1A-F5A and SI-75-2-FAA, representing the replacement of motor-operated valve 867B in the SI line. The inspectors also reviewed the accompanying weld data sheets to assess compliance with the American Society of Mechanical Engineers, Boiler and Pressure Vessel Code.

The inspectors reviewed a number of CRs attributed to the steam generator program. The review of CRs indicated that Beaver Valley personnel were entering problems into the corrective action program at an appropriate threshold, and the licensee was resolving the problems in a timely manner commensurate with the safety importance of the issue being reported.

b. Findings

No findings of significance were identified.

.2 Unit 1 Reactor Pressure Vessel Head Penetration Inspection

a. Inspection Scope

Activities inspected during the BVPS Unit 1 refuel outage included reactor pressure vessel (RPV) closure head penetration visual test (VT), ultrasonic tests (UT), and eddy current tests (ECT).

The inspection was conducted using NRC Order “Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors,” (February 11, 2003) and NRC TI 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02),” Rev. 1. The description of the inspection scope is in Section 4OA5 as specified by the TI. The specific reporting requirements of TI 2515/150 for the RPV closure head penetration VT, UTs, and ECTs are documented in the Attachment

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed Unit 2 licensed operator requalification training at the control room simulator. The inspectors reviewed the operators' ability to correctly evaluate the simulator training scenario and implement the emergency plan. The inspectors observed the operators' simulator drill performance and compared it to the criteria listed in simulator scenario "Emergency Operating Procedure (EOP) Issue 1C Familiarization Training, 2LRTS-EOP1C," Rev. 0. The inspectors observed supervisory oversight, command and control, communication practices, and crew assignments to ensure they were consistent with normal control room activities. The inspectors observed the response of the operators during the simulator drill transient and verified the fidelity of the simulator to the actual plant. The inspectors observed the effect training evaluators had in recognizing and correcting individual and operating crew mistakes including post-training remediation actions. The inspectors attended the post-drill critique in order to evaluate the effectiveness of problem identification.

b. Findings

No findings of significance were identified

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors evaluated Maintenance Rule (MR) implementation for the issues listed below. Specific attributes reviewed included MR scoping, characterization of failed structures, systems, and components (SSCs), MR risk categorization of SSCs, SSC performance criteria or goals, and appropriateness of corrective actions. The inspectors verified that the issues were addressed as required by 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance of Nuclear Power Plants," and System and Performance Engineering Administrative Manual 3.2, "Maintenance Rule Program Administration," Rev. 3.

- On February 12, the Unit 2 'A' charging pump was removed from service for various normal PM tasks. The unavailability time associated with this maintenance was extended for various reasons. During the maintenance, the decision was made to replace the shaft driven oil pump. Following maintenance, the pump was started for a surveillance run and loud noises were immediately heard following the pump start. The pump was secured, and following disassembly it was noted that the main lube oil pump was damaged. Other anomalies noted with this job included inadvertent contamination of the pump seals by overflowing lubrication oil during a system flush, foreign material exclusion issues associated with a broken feeler gage, and during final installation it was noted the pump coupling was installed backwards. The pump was ultimately returned to service on March 11. Potential deficiencies associated with this job were captured by CRs 03-02701, 03-01726, 03-01845, 03-01998, 03-01822, and 03-02618.

- On March 8, 2002, Unit 2 operators responded to an LOIA pressure event resulting from a failed instrument air dryer inlet valve (2IAS-AOV1030A). Operators successfully started two additional air compressors and isolated the leak to recover air pressure prior to any plant components inadvertently repositioning due to the degraded air pressure. Investigation determined that the 2IAS-AOV1030A valve seat had become dislodged which prevented the valve from closing. Instrument air is a MR category (a)(1) system due to previous reliability issues. The inspectors reviewed the issue and associated licensee root cause evaluation to verify the cause of the event.

b. Findings

Introduction. Ineffective corrective actions to address instrument air reliability issues for the MR category (a)(1) instrument air system resulted in an LOIA pressure transient. Specifically, planned PM was not completed on 2IAS-AOV1030A. Failure to inspect the seat ring and replace the associated O-ring permitted corrosion to build up and caused the valve to fail open. This finding was an NCV and was of very low safety significance (Green) because the issue did not cause any accident mitigation equipment or functions to be unavailable.

Description. The Unit 2 instrument air system is in MR category (a)(1) due to multiple air compressor and valve failures. Corrective actions to address an earlier NRC performance finding (see NRC Inspection Report Nos. 50-334(412)/01-10) and enable the system to achieve station reliability goals included identification and performance of several PM activities. In December 2002, a PM to overhaul 2IAS-AOV1030A was performed using (work order) WO 02-4564. In June 2002, the valve was disassembled and rebuilt as corrective maintenance using WO 01-14325. During both occasions, technicians failed to remove the valve seat and replace the O-ring, as specified in the WO instructions, because a special seat removal tool for this purpose was not available. The licensee root cause analysis determined that this lack of maintenance resulted in valve body carbon steel seat ring thread degradation, and eventual dislocation of the brass seat ring (CR 03-2553).

Technicians clearly documented that they were unable to remove the valve seat and replace the O-ring in the work-in-progress log in WOs 01-14325 and 02-4564. Station procedure Nuclear Operating Procedure WM-3001, “PM Program,” Rev. 1, requires that when a PM cannot be completed as planned, an evaluation of the incomplete PM be performed. Several methods, including consultation with the design engineer or returning the WO package to the planner for revision, are listed. In this case, an evaluation of the incomplete PM was not performed as required by NOP-WM-3001. The licensee root cause evaluation also identified that the automated system for generating PM feedback notifications didn't function properly for WO 02-4564.

Analysis. The inspectors determined the safety significance of this finding was very low (Green) using IMC 0612, Appendix 'B,' and the phase one screening process of IMC 0609, Appendix 'A'. The issue affected equipment performance under the Initiating Events cornerstone and was more than minor because it increased the likelihood of an initiating event (reactor trip).

Enforcement. The Unit 2 instrument air system is a MR category (a)(1) system based on degraded system performance. 10 CFR 50.65(a)(1) requires in part that when the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. Additionally, station procedure NOP-WM-3001, "PM Program," Rev. 1, requires that when a PM cannot be completed as planned, an evaluation of the incomplete PM be performed. Contrary to the above, from June 2002 to March 2003 corrective action (planned corrective maintenance and PM) was not properly performed on 2IAS-AOV1030A. Failure to inspect the seat ring and replace the associated O-ring as specified in WOs 01-14325 and 02-4564 instructions caused the valve to fail open on March 8, 2003, resulting in a Unit 2 LOIA event. Additionally, an evaluation of the incomplete PM was not performed. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-412/03-02-01**, Ineffective Corrective Actions to Address Degraded Instrument Air System performance (CR 03-2553).

1R13 Maintenance Risk Assessment and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the scheduling and control of maintenance activities in order to evaluate the effect on plant risk. This review was against criteria contained in NOP-OP-1005, "Shutdown Safety," Rev. 3; 1/2-ADM-2033, "Risk Management Program," Rev. 1; NOP-WM-2001, "Work Management Process," Rev. 0; 1/2-ADM-0804, "On-line Work Management and Risk Assessment," Rev. 1; NPDAP 8.30, "Maintenance Rule Program," Rev. 6; and Conduct of Operations Procedure 1/2OM-48.1.I, "TS Compliance," Rev. 9. The inspectors reviewed the routine planned maintenance, restoration actions, and/or emergent work for the following equipment removed from service:

- On January 02, Unit 1 operators received an average coolant temperature (Tave) deviation alarm 'A4-42'. The Tave indication had failed low on loop 'C'. Troubleshooting by the control room operators revealed that over power delta temperature (OPDT) and over temperature delta temperature setpoints were unchanged. The affected reactor protection channels were placed in trip in accordance with TS 3.3.1.1. Instrumentation and control technicians determined the source of the alarm was a failure of an isolator in the Tave circuit. The isolator was verified to have a short in the output fuse connector. The isolator was replaced and the channel was returned to service on January 03. A similar failure was noted on January 19, and the cause of the failure was a faulty isolator module. CRs 03-00570 and 03-00047 were generated to investigate the repeat failures of the isolator modules.

- On January 13, Unit 1 received two annunciators associated with loop ‘B’ OPDT reactor protection circuit. Further analysis revealed that the OPDT setpoint had spiked low for approximately 2 seconds. CR 03-00387 was generated to document this occurrence. The following day, four similar spikes were noted on the same channel with the last spike lasting 2.5 minutes. Channel ‘B’ OPDT was then declared out of service and placed in trip. Following troubleshooting by instrumentation and control technicians, no definitive failed component could be located. The channel functional test was completed satisfactorily, additional monitoring recorders were installed, and channel ‘B’ OPDT was returned to service. On January 19, the same channel (‘B’) of OPDT failed again for approximately five minutes. This occurred approximately five hours after restoring the ‘C’ channel OPDT to service following a Tave isolator failure. If both failures existed simultaneously, a reactor trip would have occurred. The previously installed monitoring recorders indicated that a lead/lag module was the cause of the spiking. The module was replaced and the channel was returned to service on January 20. CRs 03-00717, 03-00429, 03-00576, and 03-00715 were written to address recent reactor protection system module failures.

- On January 13, engineers identified rubber expansion joint (REJ) 2CNV-EJR210C, on the suction of the Unit 2 ‘C’ condensate pump, had several large cracks (CR 03-0428). Engineers evaluated the cracks using Specification Number 8700-DMS-0427, “REJ Procurement Specification,” Rev. 1, visual inspections, and consultation with the REJ manufacturer. The degraded REJ increased the potential for a loss of feedwater transient. Operators isolated the REJ pending assessment and determination of corrective actions. Based on engineers’ recommendations, the REJ was replaced while the plant was at power, rather than awaiting a plant outage.

- On January 20, engineers identified that a pipe penetration flood seal between the Unit 2 ‘A’ and ‘B’ SW train valve pits was not qualified for the installed location (CR 03-0598). Operators declared the seal and one train of SW inoperable, applied the appropriate TS limiting condition of operation (LCO), and established a compensatory flood watch. One day later, engineers determined that five fire seals between the two valve pits were also not qualified (CR 03-0673). A continuous fire watch was promptly stationed. Operators appropriately limited work activities on the SW system pending restoration of the penetration seals to design conditions.

- On January 22, 2002, electricians removed and replaced a 4.16 kV circuit breaker on Unit 2 bus ‘2D’ as part of a PM activity and to perform an inspection of secondary contact connections. One of the two offsite power supplies to the ‘2D’ bus was rendered unavailable for the duration of the work. In addition, a reactor coolant pump (RCP) is directly loaded to this bus, creating a plant trip risk during this maintenance evolution. This elevated risk work activity (ORANGE risk level) required several additional risk management measures. The inspectors observed the prejob briefing, chaired by the Director of Maintenance, and observed the work evolution in progress in the field to verify the activity was well understood and controlled and that compensatory measures, where appropriate, were addressed. The work activity was completed in about three hours in accordance with the WO.

- On January 23, Unit 2 operators received a Rod Control Urgent Failure alarm. Operators properly implemented the alarm response procedure, including placing rod control in manual. Control bank ‘D’ control rods were trippable, but inoperable, and the TS 3.1.3.1.d LCO was applied. Engineers, technicians, and management personnel evaluated the risk associated with online troubleshooting and repair. Troubleshooting was performed on rod control cabinet SSPC-3RD-2AC in accordance with 1/2 MI-01RC-Rod Control-I, “Troubleshooting Guide Lines for Rod Control,” Rev. 1, using WO 03-000634-000. Technicians identified an intermittent failure on a -24 volt power supply. On January 25, the power supply was repaired using WO 03-000634-002, rod control was restored to its normal configuration, and operators exited the TS LCO. Operations and management oversight was present during the troubleshooting and repair activities.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed human performance during the following non-routine plant evolutions, to determine whether personnel performance caused unnecessary plant risk or challenges to reactor safety.

- 1OM-6.4.N, “Draining the Reactor Coolant System for Refueling, Step-By-Step,” Rev. 16
- 1OM-53C.4.1.51.1, “Emergency Shutdown,” Rev. 10
- 1ICP-24-FIS151B, “FIS-FW151B AWF Pump FW-P-3B Recirculation Flow Indicator Calibration,” Rev. 5

b. Findings

Failure to Properly Test 4.16 kV Bus Protection Relay Modification

Introduction. The inspectors identified a self-revealing NCV for failure to properly test a relay modification associated with the Unit 1 ‘B’ Station Service Transformer feeder (D6 breaker) located in the ‘D’ 4.16 kV switchgear. The finding was of very low safety significance because although it caused a plant transient, alternate power sources and mitigation equipment remained available.

Description. On February 27, the Unit 1 operators were performing a plant startup and power was 58 percent. At 1330 while attempting to start the ‘B’ main feedwater pump, off-site power was lost to the ‘D’ 4.16 kV bus. The 1-2 EDG automatically started on under voltage and began supplying power to the safety-related ‘DF’ bus while the ‘D’ bus remained de-energize. The losses of the ‘D’ bus de-energize the ‘B’ condensate pump which caused the operators to have to perform an emergency down power per 1OM-53C.4.1.51.1, “Emergency Shutdown,” Rev. 10. Operators entered a 72-hour LCO in accordance with TS 3.8.1.1 for a loss of one off-site power circuit and stabilized the plant at 39 percent reactor powers. Subsequent investigation revealed that the ground fault relay on the ‘D6' offsite power supply breaker to the ‘D’ bus tripped. Troubleshooting revealed no abnormal grounds/faults. The bus was then de-energize via the ‘D6' breaker and the TS 3.8.1.1 LCO was exited at 0800 on February 28.

The event response team (ERT) identified that a recent modification, Engineering Change Package 02-0463, performed on February 7, 2003, lowered the setting on the ground fault relay from 200 amperes to 120 amperes on the ‘A’ and ‘D’ offsite power feeder circuit breakers. The EOP was implemented to correct an existing design deficiency in the circuit breaker coordination schemes associated with the Unit 1 station blackout crosstie breaker and the station service transformer breaker. A field walkdown of this modification revealed that the current transformer (CT) which provides the input signal to the ground fault relay on ‘D’ bus was not symmetrically mounted on the power cables as required by the manufacturer. This was deemed to be an existing configuration since initial plant construction. The ‘A’ bus CT appeared to be installed properly.

A review of industry experience indicated that an improperly installed CT can provide a false ground current of a magnitude that is equivalent to 10 percent of the total line current even if all three line currents are of equal magnitude. The starting of a large load (i.e., an MFW pump) creates a starting current several times the normal running current of the load. The improperly mounted CT then amplifies this higher than normal current, thus potentially causing the ground fault relay to exceed its setpoint. The EOP did not require any post-maintenance testing on the input signal (output of the CT) which could have revealed any pre-existing false ground fault currents in the detection circuit. The conclusion of the ERT was that the existing false ground current coupled with the lowered relay setting and the starting of the largest load on the bus caused the tripping of the D6 breaker and the subsequent loss of the ‘D’ 4.16 kV bus.

Analysis. The inspectors determined the safety significance of this finding was very low (Green) using IMC 0612, Appendix ‘B,’ and the phase one and two screening processes of IMC 0609, Appendix ‘A’. The issue affected equipment performance under the Initiating Events cornerstone and was more than minor because it increased the likelihood of an initiating event (reactor trip and loss of offsite power (LOOP)). Using IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a SDP Phase 1 screening and determined that the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, an SDP Phase 2 evaluation was required.

SDP Phase 2 Evaluation

Assumptions

The performance deficiency existed for between three and 30 days.

This finding increased the likelihood of an initiating event. Since the frequency of increase is not known then the initiating event likelihood for the applicable initiating event is increased by one order of magnitude.

SDP Worksheet Results

IMC 0609, Appendix A, Attachment 2, Section 1.2 addresses findings that increase the likelihood of an initiating event. An example was given which dealt with a relay calibration issue that could potentially result in a LOOP event. Using the methodology described in IMC 0609 with an exposure time of three to 30 days, the initiating event likelihood is three. However since this finding increases the likelihood of a LOOP, the initiating event likelihood of 2 is used. The most dominant sequence was the LOOP which is analyzed as follows:

LOOP (2) + EACH (3) + REC5 (2) = 7
LOOP (2) + EACH (3) + TD AFW/DRP (2) + REC2 (1) = 8
LOOP (2) + EACH (3) + RS (3) = 8 (AC recovered)
LOOP (2) + EACH (3) + HPR (3) = 8 (AC recovered)
LOOP (2) + EACH (3) + EIHP (3) = 8 (AC recovered)

EACH - Emergency AC Power
EIHP - Early Inventory Control, High Pressure Injection
HPR - High Pressure Recirculation
LOOP - Loss of Offsite Power
REC2 - Recovery of AC power in < 2 hours
REC5 - Recovery of AC power in < 5 hours
RS - Recirculation Spray
TD AFW/DRP - Turbine-driven AWF pump / Dedicated Feedwater pump

Conclusion

While this performance deficiency increased the likelihood of a LOOP initiating event, the finding was of very low safety significance (Green) because the performance deficiency existed for a short period of time and it did not impact the necessary mitigating equipment.

Enforcement. 10 CFR 50, Appendix B, Criterion XI "Test Control," requires in part that operational testing to demonstrate components will perform satisfactorily in service be performed in accordance with written test procedures which incorporate the requirements contained in applicable design documents. The test procedures shall include provisions for assuring all prerequisites for the given test have been met, adequate test instrumentation is used, and the test be performed under suitable environmental conditions. Contrary to these requirements, existing ground fault current error was not measured nor accounted for in the development of the test procedure which could have prevented the loss of the 'D' 4.16 kV bus and subsequent unplanned plant transient. This violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: **NCV 50-334/03-02-02** Failure to Properly Test 4.16 KV Bus Protection Relay Modification Causes Loss of 4160 Volt Bus Event (CR 03-04528).

Methods to Credit Manual Operator Action for Continued AFW Equipment Availability

On February 4, Instrumentation and Controls technicians calibrated flow transmitter FIS-FW151B in accordance with 1ICP-24-FIS151B, "FIS-FW151B AWF Pump FW-P-3B Recirculation Flow Indicator Calibration," Rev. 5. This transmitter provides an input signal to the recirculation valve associated with FW-P-3B ('B' AFW pump). The procedure requires the operator to place the control switch of FW-P-3B in pull-to-lock. At 0855, FW-P-3B was placed in pull-to-lock. Operators credited manual operator action capability in place of the designed auto pump start feature for continued pump availability during the calibration activity.

The inspectors noted that the controls put in place for crediting control room operator manual action differed from controls put in place when a field operator was stationed locally for manual action. Specifically, the control room operator did not have a written instruction specific to this work activity for pump restoration. The Operations manager stated that the written instructions were available in EOP E-0, "Reactor Trip or SI," Rev. 2, Attachment 1K, which operators are trained to implement after immediate actions are verified complete for events which would call for automatic AFW pump actuation. The inspectors reviewed E-0 and Attachment 1K and verified that written instructions directed the operator to verify AFW pump availability. However, the inspectors observed that this method would take a few minutes to implement and questioned whether this method met the intent of the controls specified in Nuclear Energy Institute (NEI) 99-02 "Regulatory Assessment Performance Indicator Guideline," Rev. 2, for crediting manual operator action in place of automatic features for safety-related mitigation equipment. The licensee initiated a frequently asked question (FAQ) to address this issue. This issue is an unresolved item pending FAQ review and resolution by a joint NRC/NEI panel (CR 03-06071) **(URI 50-334/03-02-03)**.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability evaluations in order to determine that proper operability justifications were performed for the following items. In addition, where a component was determined to be inoperable, the inspectors verified the TS LCO implications were properly addressed.

- In January and February 2003, the Unit 2 containment high temperature instruments were often in an alarm condition, indicating a possible steam or reactor coolant leak. The inspectors questioned the cause of the frequent alarms which the operators had become accustomed to. Evaluation of historical temperature profiles demonstrated a seasonal effect on temperature instruments located near the perimeter of the containment structure. The alarm setpoints were too restrictive, resulting in unnecessary alarms during normal operating conditions. Engineers discussed temperature profiles and associated environmental qualifications with the inspectors and recommended alarm setpoint revisions to eliminate the unnecessary containment high temperature alarms (CR 03-1188).

- On January 27, the Unit 1 No. 2 vital bus 120 volt inverter indicated degraded voltage, just 0.2 volts above the minimum required for operability (121.6 volts). Engineers and technicians investigated the voltage reading and concluded the inverter was operable and not degrading (CR 03-0730). Engineers determined that the reduced inverter output voltage was due to a recent 10-year overhaul performed on the inverter. Corrective actions for further diagnostics on the inverter were scheduled for the upcoming refueling outage. Additionally, the test equipment used to monitor inverter output voltage, since the overhaul, was defective and subsequently replaced (CR 03-1000).

- On January 20-21, engineers identified that a piping penetration flood seal and five piping penetration fire seals between the Unit 2 ‘A’ and ‘B’ SW train valve pits were degraded in that they did not meet design qualification requirements (CRs 03-0598 and 03-0673). The inspectors reviewed various design documents and WOs, inspected the SW valve pit area, and discussed design requirements with engineers. The engineers concluded that the penetrations were inoperable and correspondingly, one train of SW was inoperable. The root cause of the inoperable penetration seals was due to design control errors during original plant construction. Engineers subsequently performed additional testing which verified that the installed seals would perform their safety function. Therefore, both SW trains remained operable.

- On February 24, a reactor trip and SI actuation occurred on Unit 1. As a result of the SI signal, a containment isolation phase ‘A’ signal isolated the normal RCP seal leak off flow path. By design, the seal return header relief valve, RV-1CH-382A, opened to divert seal leak off flow to the pressurizer relief tank (PRT). Level increase in the PRT was noted following the Containment Isolation Phase A, which indicated the relief valve performed its function. Subsequent reactor coolant system (RCS) leak tests revealed an increase in RCS leakage. Investigation by the ERT concluded that following termination of SI/CIA and restoration of the normal RCP seal return flow path to the volume control tank, RV-1CH-382A failed to reclose. The leakage through RV-1CH-382A was calculated to be 0.2 gallons per minute (gpm). BCO 1-03-001 was generated to evaluate operability of this relief valve as well as continued plant operation with the 0.2 gpm identified RCS leakage. The BCO concluded that the valve would continue to perform its safety function (i.e., provide continued RCP seal leak off flow path following an SI/CIA) and that the PRT level increase would be controlled by the reactor operators since the rate of level increase would be slow, even at the maximum design valve flowrate of 8.2 gpm. Additionally, the PRT rupture disk which has a setpoint of 85 psig would not be challenged even if the tank became filled since the system pressure would be maintained at volume control tank pressure (~35 psig).

- On March 11, 2003, Unit 2 pressurizer power operated relief valve (PORV) 2RCS-PCV456 exhibited leakage following a periodic stroke test. The leakage was stopped by shutting the associated PORV block valve. On March 22 operators attempted to restore the normal configuration alignment, but observed approximately 3-gallons per minute leak by when 2RCS-PCV456 was unisolated. Operators shut the block valve, performed an evaluation, and concluded that the PORV remained operable and available. The inspectors reviewed the applicable TSs, UFSAR, and inservice test program to verify regulatory requirements for operability were met (CRs 03-2780 and 03-3709).

- The Unit 2 recirculation spray heat exchanger radiation monitors are designed to monitor a potential radiation release path during certain design basis accidents. The latent issues review team identified several functional concerns regarding SW cooling necessary to support radiation monitor operation (CR 02-5781). While reviewing the issue, the inspectors further identified that operators would isolate cooling to the radiation monitors (per EOPs) during a design basis accident if offsite power remained available. The inspectors discussed these issues with engineers who initiated appropriate corrective actions (CR 03-3855).

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed and/or observed several post-maintenance tests (PMTs) to ensure: 1) the PMT was appropriate for the scope of the maintenance work completed; 2) the acceptance criteria were clear and demonstrated operability of the component; and 3) the PMT was performed in accordance with procedures. The following PMTs were observed:

- On January 25, a +24 volt power supply for Unit 2 rod control cabinet SSPC-3RD-2AC was replaced using WO 03-000634-002. 2OST-1.1, “Control Rod

Assembly Partial Movement Test," Rev. 4, and power supply voltage monitoring using WO 03-000634-002 was performed as a PMT.

- On February 20, engineers observed water in the Unit 2 'A' train supplemental leak collection and release system (SLCRS) charcoal filter enclosure. The apparent cause was leakby from the fire protection deluge system. Operators declared the 'A' SLCRS train inoperable. Following replacement of the charcoal, 2OST-16.1, "SLCRS Exhaust Fans and Remote Damper Component Test - Train 'A'," Rev. 10; 2BVT-1.16.6, "SLCRS Train 'A' Filter Efficiency and Flow Test," Rev. 5; and 2BVT-1.16.8, "SLCRS Train 'A' Charcoal Sample," Rev. 3 were performed.

- On February 24, following a steam line isolation and concurrent SI signal on Unit 1, all three MSIVs experienced fast closure while passing full steam flow. This resulted in the rupture of all six (2 per steam line) MSIV blowout plugs. This is a normal expected response while at full power due to the fact that once the MSIV begins to close and the valve enters the flow stream, steam flow forces the MSIV closed. Since the rate at which the actuator disk compresses the air inside the actuator is greater than the rate that the air vents off the actuator, the actuator housing actually becomes pressurized and causes the blow out plugs to burst. The blowout plugs were subsequently replaced and the MSIVs were stroke tested satisfactorily on February 26 using procedures 1OST-21.4, "Main Steam Trip Valve [TV-1MS-101A]," Rev. 11, 1OST-21.5, "Main Steam Trip Valve [TV-1MS-101B]," Rev. 11, 1OST-21.6, "Main Steam Trip Valve [TV-1MS-101C]," Rev. 11. These PMTs verified that the MSIVs would close in less than five seconds.

- Following replacement of the charcoal absorber in the 'B' filter bank of the Unit 1 SLCRS, a PMT was performed on February 13 in accordance with 1BVT-1.16.7, "Supplementary Leak Collection and Release System [VS-FL-7, 8, 9] Filter Efficiency Test and Flow Test," Rev. 7. This PMT verified the operability of the SLCRS system within the limits described in TS 4.7.8.1.b1, 4.7.8.1.b2, 4.7.8.1.b3, 4.7.8.1.b4 and 4.7.8.1.c1.

- On March 11, maintenance on the Unit 2 'A' charging pump was completed which included replacement of the shaft driven oil pump, mechanical seal change out and various other PM items. The PMT was the performance of 2OST-7.4, "Centrifugal Charging Pump [2CHS*P21A]," Rev. 21. The PMT was completed satisfactorily.

- On February 12, following normal PM on 2MSS-SOV105F (Unit 2 turbine driven AFW pump steam line C isolation valve) under WO 02-011842-000 which included replacement of the reed switches, terminal board, rectifier, and cover gasket, the valve was stroke tested in accordance with 2OST-24.4, "Steam Driven Auxiliary Feed Pump [2FWE*P22]," Rev. 46. The simultaneous open stroke of 2MSS-SOV105C and 2MSS-SOV105F also tests the cold fast start of the turbine driven AFW pump. The initial stroke times for 2MSS-SOV105C and

2MSS-SOV105F were 2.4 and 2.13 seconds, respectively, exceeding the stroke time limit of 2.0 seconds for fast acting valves. Subsequent strokes (open and closed) were performed on 2MSS-SOV105C and 2MSS-SOV105F and all stroke times were satisfactory. An engineering evaluation was performed and concluded that the initial stroke failure was due to a combination of operator reaction time on the first set of fast acting valves and the fact that the steam line in the 2MSS-SOV105C and 'F' flow path had been manually isolated which could allow condensation to build up in the piping prior to return to service.

- On February 20, replacement of the Unit 2 'A' service water pump check valve, 2SWS-57, was completed using WO 02-014832-000. The subsequent PMT consisted of a forward flow check per 2OST-30.02, "Service Water Pump [2SWS*P21A] Test, " Rev. 25, and reverse flow check per 2OST-30.06A, "Service Water Pump [2SWS*P21C] Test on Train 'A' Header," Rev. 8. Both tests were performed with satisfactory results.

- On March 27, following replacement of the No. 4 station battery, a 2-hour battery service test was completed in accordance with 1BVT-1.39.4, "Station Battery [BAT-4] Service Test," Rev. 4. The test was performed in accordance with Institute of Electrical and Electronic Engineers 450-1980 and TS 4.8.2.3.2.d. The test was completed with satisfactory results.

- In November 2002, a modification was performed on Unit 1 to all four recirculation spray heat exchanger radiation monitors, RM-RW100A, B, C, and D using WOs 01-017020, 21, 22, and 23. This modification added a flushing line to help preclude clogging/fouling of the radiation monitors. The post-modification PMT was satisfactory. However, in March of 2003 during the full flow testing of the river water side of the recirculation spray heat exchangers (1OST-30.12A, B) the red 'low flow' light on all four radiation monitors did not extinguish. Discussions with the system engineer concluded that the low flow condition will be evaluated in April of 2003 during a re-performance of the full flow operational surveillance test (OST), by using a strap-on flow transmitter.

- On January 22, 2OST-36.5, "Manual Transfer from Unit to System Station Service Transformer," Rev. 3, was performed following electrical breaker replacement on the Unit 2 4.16 kV 'D' bus and replacement of a secondary contact block.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed selected reactor shutdown, refueling, outage maintenance, and reactor startup activities to determine whether shutdown safety functions (e.g., reactor decay heat removal, reactivity control, electrical power availability, reactor coolant inventory, spent fuel cooling, and containment integrity) were properly maintained as required by TSs and license conditions and 1/2-ADM-1800, “Shutdown Safety,” Rev. 0. Specific performance attributes evaluated included configuration management, communications, instrumentation accuracy, and identification and resolution of problems. The inspectors closely evaluated configuration and inventory control during periods of reduced reactor RCS inventory due to the associated increase in shutdown risk. Specific activities evaluated included:

- 1OM-6.4.N, “Draining the RCS for Refueling,” Rev. 16. The inspectors focused on the adequacy of the reactor water level instrumentation in the control room and the temporary level indication installed in the containment building.
- 1OM-6.4.P, “RCS Make-Up From Refueling Water Storage Tank,” Rev. 4
- 1OM-6.4.W, “Venting the RCS to Atmospheric Pressure,” Rev. 5
- 1OM-6.4.AO, “Isolating and Draining RCS Loop,” Rev. 14
- 1OM-6.4.AT, “Venting the Reactor Vessel Head to the Pressure Relief Tank in Mode 5,” Rev. 1
- 1OM-51.4.D, “Cooldown From Mode 4 to Mode 5,” Rev. 29
- 1OM-53C.4.1.10.1, “Residual Heat Removal System Loss,” Rev. 6
- 1/2RP-3.16, “Refueling Procedure Core Unload,” Rev. 2
- The inspectors reviewed the Unit 1 refueling outage 15 (1R15) Pre-Outage Shutdown Safety Review performed by the Nuclear Quality Assessment Section, Probabilistic Risk Assessment Engineering Group and Unit 1 Operations. The inspectors reviewed the key safety functions associated with: 1) electrical power to the emergency bus; 2) decay heat removal; 3) boration and inventory control; and, 4) containment integrity.
- Prior to offloading fuel assemblies from the reactor, containment integrity controls were required as specified in 1OST-47.3D, “Verification of Administrative Closure Controls for Containment/Fuel Building During Refueling,” Rev. 3. The inspectors reviewed the OST which described the necessary actions for rapid closure of the containment equipment and personnel hatches and performed a walkdown of the containment hatches in order to verify that the administrative controls were in place as described in the OST.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and reviewed the following OSTs and BVT, concentrating on verification of the adequacy of the test as required by technical specifications to demonstrate operability of the required system or component safety function.

- 1OST-36.1, "Diesel Generator No.1 Monthly Test," Rev. 34
- 1OST-1.12, "Safeguards Protection System Train B Test," Rev. 23
- 1BVT-1.13.5, "Inside Recirculation Spray Pump Test," Rev. 15
- 1OST-13.7, "Recirculation Spray Pumps Auto Start and Flow Test," Rev. 11
- 2OST-30.2, "Service Water Pump [2SWS*P21A] Test," Rev.25
- 2OST-13.1, "Quench Spray Pump [2QSS*P21A] Test," Rev. 19
- 2OST-11.2, "Low Head SI Pump [2SIS*P21B] Test," Rev. 18

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

The inspectors reviewed radiological work activities and practices and procedural implementation during observations and tours of the facilities and inspected procedures, records, and other program documents to evaluate the effectiveness of the access controls to radiologically significant areas.

On March 18, 19, and 20, 2003, the inspectors, on three separate occasions, toured the radiologically-controlled area (RCA). The observed areas included the reactor containment, auxiliary, fuel handling, and turbine buildings of Unit 1 and the auxiliary, fuel handling, and turbine buildings of Unit 2, the common health physics access control point on the third floor of the South Office and Shop Building, and the limited RCA access/egress point off the turbine deck of Unit 1. At the common control point, the inspectors observed radiation workers logging into the RCA on radiation work permits (RWPs) using electronic dosimeters and observed radiation workers exiting the RCA and then logging out of their RWPs. The inspectors examined the use of personnel dosimetry and the radiological briefings for incoming radiation workers. Also, during these walkdowns the inspectors observed and verified the appropriateness of the posting, labeling, and barricading of radioactive material, radiation, contamination, high radiation, and locked high radiation areas. The inspectors used a portable radiation survey meter to verify radiological conditions. The inspectors observed work activities by both radiation workers and radiation protection technicians for compliance with the radiological work permit (RWP) requirements and radiological protection procedures. The inspectors reviewed work activities covered by outage RWPS (RWPs 103-4030, -4040, -4066, -4069, -4081, and -4083) (See also the List of Documents Reviewed section.)

Based on a review of data and on discussions with the site's radiological protection personnel, the inspectors found that there were no documented internal doses greater than 50 millirems or airborne radiation areas with potential for greater than 50 millirems in internal exposure in 2003. Also, the inspectors discussed the procedures for the relocation of whole body personnel monitoring devices and the use of extremity badges. Currently, the only instance of whole body personnel monitoring device relocation was for steam generator channel head entries.

On March 20, 2003, the inspectors discussed CR 03-00244, which dealt with a neutron-activated metal clip, with two radiological protection supervisors. The inspectors discussed the issue with the radiological protection manager on March 21, 2003.

The inspection included a selective review of documents and procedures (as listed in the List of Documents Reviewed section) to evaluate the adequacy of radiological controls.

The review was against criteria contained in 10 CFR 19.12, 10 CFR 20 (Subparts B, C, D, F through J, L, and M), site Technical Specifications, and site procedures.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspectors reviewed the effectiveness of the licensee's program to maintain occupational radiation exposure as low as is reasonably achievable (ALARA).

The inspectors reviewed the site's actual versus projected cumulative collective exposure for the current refueling outage, 1R15. The inspectors reviewed the 1R15 Daily Exposure Summaries for March 17 through March 21, 2003, which listed the exposure incurred on the last shift, the total exposure to the present date, the person-rem estimate, and percent of the estimate for each outage RWP. The inspectors reviewed automatic reevaluations of dose estimates by ALARA group personnel. The inspectors selectively reviewed prejob and ongoing ALARA reviews associated with the RWPs cited in Section 2OS1.

The inspectors reviewed individual exposure tracking reports provided to individual work groups on each shift during the refueling outage. The inspectors also reviewed exposure records for declared pregnant workers and discussed the recordkeeping with the dosimetry supervisor.

On March 19, 2003, the inspectors observed an ALARA prejob briefing for RWP 103-4072 which dealt with foreign object removal in the steam generator secondary sides, to evaluate the adequacy of the radiological information and controls provided. On March 20, 2003, the inspectors observed the ALARA prejob briefing for RWP 103-4081, which dealt with the installation of magnetic thermocouples on the detached reactor head.

The inspectors performed a selective examination of documents and procedures (as listed in the List of Documents Reviewed section) for regulatory compliance and for adequacy of control of radiation exposure.

The review was against criteria contained in 10 CFR 20.1101 (Radiation protection programs), 10 CFR 20.1701 (Use of process or other engineering controls), and site procedures.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

a. Inspection Scope

The inspectors reviewed the program for health physics instrumentation and for installed radiation monitoring instrumentation to determine the accuracy and operability of the instrumentation.

During the plant tours described in Section 2OS1, the inspectors reviewed field instrumentation used by health physics technicians and plant workers to measure radioactivity and radiation levels, including portable field survey instruments, hand-held contamination frisking instruments, teledose meters, continuous air monitors, personnel contamination monitors, and portal monitors. The inspectors verified current calibration, source checking, and proper instrument function. The inspectors also identified and noted the condition, operability, and calibration status of selected installed area and process radiation monitors and any accessible local indication information for those monitors.

The inspectors performed a selective examination of documents and procedures (as listed in the List of Documents Reviewed section) for regulatory compliance and adequacy.

The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, site TSs, and site procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Unplanned Scrams and Scrams with Loss of Normal Heat Sink

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 performance indicators for unplanned scrams per 7000 critical hours and scrams with loss of normal heat sink to verify scrams had been properly reported as specified in NEI 99-02, Rev. 1 and Rev. 2. The inspectors verified the accuracy of the reported data through reviews of Licensee Event Reports, monthly operating reports, plant operating logs, and additional records. The inspectors reviewed 1 year of data (January to December 2002) for unplanned scrams and three years of data (ending December 2002) for scrams with loss of normal heat sink. No problems with performance indicator accuracy or completeness were identified.

b. Findings

No findings of significance were identified.

.2 Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment

a. Inspection Scope

The inspectors reviewed the licensee's programs for gathering, processing, evaluating, and submitting data for the Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment Performance Indicators (PIs) to verify these PIs had been properly reported as specified in NEI 99-02. The review included the licensee's tracking and trending reports, personnel interviews, and security event reports for the PI data collected from the second quarter of 2002 through February 2003.

b. Findings

No findings of significance were identified.

.3 Drill and Exercise Performance, Emergency Response Organization (ERO) Participation, and Alert Notification System Reliability

a. Inspection Scope

The inspectors reviewed the licensee's process for identifying the data that is used to determine the values for the three emergency preparedness (EP) PIs which are: 1) Drill and Exercise Performance, 2) ERO Participation, and 3) Alert Notification System Reliability. The review assessed data submitted to the NRC from the second, third and fourth quarters of 2002 (since the last EP PI verification inspection). Classification, notification, and protective action opportunities were reviewed from licensed operator requalification simulator sessions and site ERO drills and exercises. Attendance records for drill and exercise participation was reviewed for completeness and accuracy. Test records were reviewed and details of the siren testing and data collection were discussed with individuals responsible for that program. The inspectors reviewed this data using the criteria of NEI 99-02.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Occupational Radiation Safety

a. Inspection Scope

The inspection included a review of the following issues identified in the corrective action program for the appropriateness and adequacy of event categorization, immediate corrective action, corrective action to prevent recurrence, and timeliness of corrective action: CR Nos. 03-00244, 03-01403, 03-01525, 03-01646, 03-01701, 03-01729, 03-01816, 03-01934, 03-01951, 03-01966, 03-02090, 03-02464, and 03-03520.

b. Findings

On January 8, 2003, CR 03-00244 documented that a 2" x 3" neutron-activated metal clip, containing about 2.7 millicuries of mixed radionuclides (as of November 15, 2002), was found during the processing of soiled anti-contamination clothing at the licensee's licensed laundry vendor. The metal clip was determined to be part of an excore detector support assembly which had been worked on during the Unit 1 maintenance outage (November 2002). The laundry was shipped in November 2002 as a controlled radioactive materials shipment. The clip was apparently placed in a receptacle for soiled anti-contamination clothing. The metal clip indicated about 500 millirems per hour (mR/hr) (gamma) on contact and 8 mR/hr at 12 inches. At the time of this inspection the inspectors were not able to complete a review of this matter relative to the licensee's conformance with applicable regulatory requirements. The licensee's review of dosimetry results did not identify any unplanned exposures associated with this matter. Notwithstanding, this issue is an unresolved item pending additional NRC inspectors' review **(URI 50-334/03-02-04)**.

.2 Reactor Operator Left the Control Room Without Turnover

On February 10, 2003, the Unit 1 reactor operator (RO) left the control room to go to the shift turnover briefing (in a separate conference room) without obtaining a relief, while the reactor was in Mode 1 (power operation). After approximately 1-2 minutes, the Shift Manager recognized the absence of the RO and promptly restationed another RO at the controls. This event demonstrated that corrective actions to a similar control room staffing issue at Unit 2 were not fully effective. This licensee identified violation is documented in Section 4OA7.

.3 Reactor Vessel Head Penetration Inspection Oversight

a. Inspection Scope

The extent of involvement in monitoring contracted non-destructive examination tasks to provide a timely opportunity to identify and resolve problems were observed. The inspectors verified that management oversight and Quality Assurance surveillance of non-destructive examination on the RPV head penetration control rod drive mechanism (CRDM) examinations by VT, UT and ECT were ongoing and that identified problems, for example CR 003-04203, were entered into the corrective action program, evaluated, and appropriately dispositioned.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up

a. Inspection Scope

On February 24, 2003, at 3:48 p.m., Unit 1 experienced an automatic SI actuation due to low steam line pressure followed by an automatic reactor trip from 100 percent power. The main steam lines isolated as designed, resulting in a loss of normal heat sink for decay heat removal. Operators used the steam generator (SG) atmospheric steam dumps to remove decay heat. The event was initiated by construction workers who inadvertently damaged the ‘C’ MSIV actuator air supply rupture disk while erecting scaffolding (CR 03-1995). The ‘C’ MSIV unexpectedly closed causing a rapid flow increase and corresponding depressurization of the remaining two main steam headers. This rate-of-change in steam pressure caused a low steam line pressure signal to the safety injection actuation circuitry. SI actuated and initiated an automatic reactor trip as designed.

The inspectors responded to the control room to evaluate plant equipment and mitigating system response to the trip, operator actions including communications and use of correct EOPs, and plant stabilization to a safe shutdown condition. Operators implemented EOP E-0, “Reactor Trip or SI,” Rev. 4, and dispatched additional personnel to determine whether a steam rupture existed. At 4:00 p.m. the Shift Manager declared an Unusual Event in accordance with criteria specified in Emergency Action Level 2.10, “Main Steam Line Break.” State and local officials were notified of the event within 15 minutes of the declaration. Operators terminated SI in accordance with ES-1.1, “SI Termination,” Rev. 2. The Unusual Event was terminated at 5:35 p.m. based on completion of the EOP actions, termination of SI, and the plant being stable at normal operating temperature and pressure. The inspectors observed operator actions, reviewed various instruments and sequence of events recorders, and conducted interviews to verify safe plant conditions.

Immediately following plant stabilization the inspectors reviewed the event's risk significance with licensee risk analysts and the NRC regional senior risk analyst. The inspectors determined that the conditional core damage probability was very low (approximately 3E-6) and following discussion with regional NRC management, determined that no additional NRC reactive response was necessary. Due to preexisting minor RCS leakage into the 'B' SG and use of the SG atmospheric steam dumps for decay heat removal, there was a minor airborne radioactivity release during this event. The release was approximately 1/1000 of the associated annual regulatory limit for gaseous radioactivity release.

The inspectors attended the Unit 1 Readiness for Restart Assessment Meeting and monitored various equipment repair activities to determine whether station personnel properly evaluated plant readiness for safe restart in accordance with procedure 1/2-ADM-0703, "Event Review," Rev. 0. The Event Review Team (ERT) concluded that the apparent cause of the reactor trip was failure to properly control scaffolding activities in the vicinity of safety-related equipment (the 'C' MSIV actuator). The inspectors determined that adequate measures were implemented to preclude repetitive challenges to safety-related equipment upon restart, as required by 1/2-ADM-0703.

b. Findings

Introduction. The inspectors identified a self-revealing NCV of very low safety significance (Green) regarding the failure to properly plan and control maintenance activities (scaffold erection) in the vicinity of the 'C' MSIV that led to an unplanned Unit 1 SI actuation and reactor trip. This finding represented human performance errors in both the prejob-job risk review and the scaffold erection activity. This finding was of very low safety significance because of its short duration and the issue did not affect the necessary mitigating equipment.

Description. Construction workers were erecting scaffolding in the Unit 1 main steam valve room in preparation for planned refueling outage maintenance activities to begin in early March 2003. While positioning scaffold poles in the area below the 'C' MSIV actuator, a pole was moved through an opening in the overhead grating. The pole punctured a rupture disk on one of the two air operating cylinders that hold the MSIV open. The rupture disk failed, which vented instrument air pressure from the actuator, causing closure of the MSIV.

1/2-ADM-0805, "Production/Generation Risk Determination," Rev. 2, specifically excluded scaffolding activities from risk reviews. Procedure BVSG-002, "Scaffold Erection and Tagging," Rev. 3, required an operations department review and approval of the scaffold erection activity. The review for this activity failed to identify potential plant sensitive equipment such as the MSIV actuator rupture disk. The ERT also identified that the rupture disk was originally supplied with a light-weight debris catch basket that is no longer installed. Although not intended for this purpose, the basket may have protected the rupture disk from damage if it had been installed.

Analysis. In accordance with IMC 0612, Appendix B, “Issue Disposition Screening,” the inspectors determined that the issue was more than minor because the performance deficiency was similar to Example 4.b of IMC 0612, Appendix E, “Examples of Minor Issues,” in that, the failure to properly preplan and control the scaffold erection activities in the vicinity of the ‘C’ MSIV led to an unplanned Unit 1 SI actuation and reactor trip. Using IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a SDP Phase 1 screening and determined that the finding degraded both the initiating event and mitigating systems cornerstones. Therefore, an SDP Phase 2 evaluation was required.

SDP Phase 2 Evaluation:

Assumptions

- The performance deficiency resulted in an increase in the likelihood of the Transient without Power Conversion System (TPCS) initiating event.
- The performance deficiency existed for less than three days.
- The power conversion system was not recoverable following the event.

SDP Worksheet Results

The most dominant sequence was the reactor trip with a loss of power conversion system which is analyzed as follows:

TPCS (2) + AFW (4) + RS (3) = 9
TPCS (2) + AFW (4) + HPR (3) = 9
TPCS (2) + AFW (4) + FB (2) = 8
TPCS (2) + AFW (4) + EIHP (3) = 9

AFW - Secondary Heat Removal, AWF
EIHP - Early Inventory Control, High Pressure Injection
FB - Primary Heat Removal, Feed and Bleed
HPR - High Pressure Recirculation
RS - Recirculation Spray

Conclusion

While this performance deficiency increased the likelihood of a TPCS initiating event, the finding was of very low safety significance (Green) because the performance deficiency existed for a very short period of time and it did not impact the necessary mitigating equipment.

Enforcement. TS 6.8.1 requires in part that procedures be established and implemented covering the activities identified in Appendix ‘A’ of Regulatory Guide 1.33, Rev. 2, February 1978. Appendix ‘A’ requires in part that maintenance that can affect the performance of safety-related equipment be properly preplanned and performed in accordance with written procedures or instructions appropriate to the circumstances. Procedure BVSG-002 and 1/2-ADM-0805 require an operations department representative to review the scaffold erection activity to identify potential hazards to plant sensitive equipment. BVSG-002 also requires proper care during scaffold erection activities so as not to damage plant equipment. Contrary to the above, on February 24, 2003, operators failed to identify the ‘C’ MSIV actuator blowout disk as potential plant sensitive equipment in the vicinity of the intended scaffold erection prior to authorizing the work. Additionally, construction workers failed to properly control their work activity and damaged the ‘C’ MSIV actuator, causing a SI and reactor trip with loss of heat sink event. Because this failure to properly implement procedures was of very low safety significance and has been entered into the corrective action program (CR 03-1995), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-334/03-02-05**, Failure to Adequately Control Scaffold Activities Causes MSIV Closure and Reactor Trip.

4OA5 Other Activities

TI 2515/150 - Circumferential Cracking of RPV Head Penetration Nozzles

a. Inspection Scope

The inspectors reviewed the licensee’s activities to detect circumferential and axial cracking of RPV head penetration nozzles. The inspection was conducted using NRC Order, “Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors” (February 11, 2003), the response by the BVPS site to the Order dated March 3, 2003, and TI 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles” (NRC Bulletin 2002-02), Rev.1.

The inspection included interviews with UT and ECT analyst personnel, reviews of qualification records and procedures, and observations of selected video tape records of the closure head VT. The operation of the ECT and UT equipment and evaluation of results were observed. A sample of the completed VT, UT, and ECT of the RPV head penetrations were reviewed. The licensee’s basis for determining the effective degradation years for the Unit 2 head was reviewed. In accordance with TI 2515/150, the inspectors verified that deficiencies and discrepancies associated with the RCS structures and the examination process, if identified, would be placed in the licensee’s corrective action process. The specific reporting requirements of TI 2515/150, Rev. 1, are documented in the Attachment.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Mark Bezilla and other members of licensee management following the conclusion of the inspection on April 3, 2003. The licensee acknowledged the findings presented.

The licensee did not indicate that any of the information presented at the exit meeting was proprietary.

4OA7 Licensee-Identified Violations

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

10 CFR 50.54.k requires that a RO or senior RO shall be present at the controls at all times during the operation of the facility. Procedure 1/2OM-48.1.A, "Responsibilities of the Operations Group," Rev. 1, states, "The RO shall not leave his assigned unit's Control Room Area whenever the unit is in Mode 6, without obtaining a qualified relief operator."..Contrary to the above on February 10, 2003, the Unit 1 RO left the control room to go to the shift turnover briefing (in a separate conference room) without obtaining a relief while the reactor was in Mode 1 (power operation) (Section 4OA2).

ATTACHMENT: SUPPLEMENTAL INFORMATION

LIST OF PERSONS CONTACTED

Licensee personnel

M. Bezilla, Vice President
T. Cosgrove, Director, Work Management
R. Donnellon, Director, Maintenance
L. Freeland, Manager, Nuclear Regulatory Affairs & Corrective Actions
R. Freund, Rad Ops Supervisor, Unit 2
J. Lash, Plant General Manager
J. Lebda, Supervisor, Radiological Engineering and Health
M. Pearson, Director, Nuclear Services
P. Sena, Manager, Nuclear Operations
J. Sipp, Manager, Nuclear Radiation Protection, Rad Ops, Units 1 and 2
F. von Ahn, Director, Plant Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-334/03-02-03	URI	Methods to Credit Manual Operator Action for Continued AFW Equipment Availability (Section 1R14)
50-334/03-02-04	URI	NRC to Review Circumstances Associated with Shipment of a Radioactive Part to a Vendor Laundry (Section 4OA2)

Opened/Closed

50-412/03-02-01	NCV	Ineffective Corrective Actions to Address Degraded Instrument Air System performance (Section 1R12)
50-334/03-02-02	NCV	Failure to Properly Test 4.16 KV Bus Protection Relay Modification Causes Loss of 4160 Volt Bus Event (Section 1R14)
50-334/03-02-05	NCV	Failure to Adequately Control Scaffold Activities Causes Main Steam Isolation Valve Closure and Reactor Trip (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Section 1R08: Inservice Inspection

Steam Generators

ISIE-EOP-2, Rev. 14, Steam Generator Examination Program
FENOC-03-60, Steam Generator Inspection Logic Charts
SG-SGDA-03-02, Rev. 1, BVPS Unit 1, Steam Generator Degradation Assessment 1R15, Refueling Outage, January 2003
Beaver Valley Unit 1, Cycle 15, Voltage-based Repair Criteria 90 Day Report Submittal 2002
CR-03-02806, Air Compressor Dryer for the 1R15 Steam Generator Project
CR-03-02939, Steam Generator Handholes/Sludge Lanc Work
CR-03-03004, Improvements for the Steam Generator work Activities
CR-03-03048, Beaver Valley 1 RC-E-1C Steam Generator
CR-03-03337, Steam Generator A (Secondary Side)
CR-03-03556, Westinghouse Steam Generator Tech Contaminates Foot
CR-03-03439, Nuclear Quality Assurance Recommendation Regarding Steam Generator Exam Procedure
CR-03-03541, Broken Wire in Steam Generator Inspection Robot

CRDMs

Procedure MRS-SSP-1398, “Reactor Vessel Head Penetration Remote Visual Inspection for Beaver Valley Electric Generating Plant, Unit 1 (DLW)” Rev. 1
Report BOP-VT-03-1-019, ”Visual Examination Results of the RVH and Penetrations,” Rev. 0
Letter L-03-008), dated 3/17/03 from BVPS to NRC on Proposed Alternative Repair Methods for RVH penetrations, (Relief Request No. BV3-RV-01).
CRDM Calibration Block (Pipe) SAP# 102901, As-built Drawing D 6D3**89, Rev. 3.
Procedure WDI-ET-002, “Eddy Current Examination of ‘J’ Groove Welds,” Rev. 2
Procedure WDI-ET-003, “Eddy Current Examination Imaging for RPV Head Penetrations from Tube ID,” Rev. 4
Procedure WDI-ET-004, "Eddy Current Examination Analysis Guidelines for Weld and Tube OD,” Rev. 2
Procedure WDI-ET-008, “Eddy Current Examination Imaging for RPV Head Penetrations from Tube ID with the GAP Scanner,” Rev. 1
Procedure WDI-UT-010, “Ultrasonic Testing of RPV Head Penetrations,” Rev. 4
Procedure WDI-UT-011, “Ultrasonic Testing of RPV Head Vent Tube,” Rev. 2
Procedure WDI-UT-013, “CRDM Ultrasonic Testing Analysis Guidelines,” Rev. 2

Section 1R15: Operability Evaluations

CR 03-00598
1/2 ADM-2021, “Control of Penetrations (Including HELB Doors)”

Promatec VTI “Typical Details,” (seal installation requirements/qualification field document):
- 2601.337-844-001D, “Flexible Pressure Seals P-1, 2, 3"

- 2601-337-844-082B, “Electrical Fire Seals EL-1, 2"
- 2601-337-844-009D, “Mechanical Fire Seals MS-1, 2, 3, 4"

Original Installation Documents (Promatic QC-3A.2, Engineering Release & Inspection Report):

- Release No. 03969 for Sleeve S3016 (mechanical penetration)
- Release No. 03963 for Sleeve 2WS900N08 (electrical penetration)
- Release No. 08143 for Sleeve 2WS900N08 B1 (electrical penetration), (i.e., “breach”)
- Release No. 03958 for Sleeve 2WC900O06 (electrical penetration) (not breached since original installation)

WO 01-021982-015 for the seal installed sleeve S03016 for EOP 02-0253 in August (includes, “Penetration Sealing Information,” form that indicates Typical Detail - MS-1)

Calculation 8700-NS(B)-273, “BVPS-1 Aux. Bldg. Door Study for PRA Flooding Scenarios,” Rev. 0

Design Drawings:

10080-RE-0037R, “Concealed Conduits & Sleeves CLG Tower Pump Hse & Valve Pit,” Rev. 8
10080-RO-0068A, “Sleeve Schedule Miscellaneous Buildings,” Rev. 13
IDCN 2-RP-0068A-E02-0253-02, Rev. 0
10080-RP-0068B, “Sleeve Location Miscellaneous Buildings,” Rev. 11
IDCN 2-RP-0068B-E02-0253-02, Rev. 0

Section 2OS1: Access Control to Radiologically Significant Areas

Documents

-RWP 103-0510, Valve repair-all areas outside of the reactor containment building, Rev. 0
-RWP 103-4014, I&C-Routine maintenance. Rev. 0
-RWP 103-4020, ISI, Rev. 0
-RWP 103-4030, Refuel operations/disassembly-reassembly, Rev.0
-RWP 103-4038, Steam generator secondary side sludge lancing/video inspection, Rev. 0
-RWP 103-4040, Steam generator platform support, Rev. 0
-RWP 103-4048, Valve repair on elevation 718 of the reactor containment building, Rev. 0
-RWP 103-4066, Reactor coolant pump (1 RC-P-1B) seal inspection/repair, Rev. 0
-RWP 103-4069, CRDM nozzle and reactor head inspection, Rev. 0
-RWP 103-4070, Containment scaffolding/erect and remove, Rev. 0
-RWP 103-4072, Steam generator secondary side foreign object removal, Rev. 0
-RWP 103-4077, Steam generator replacement project, Rev. 0
-RWP 103-4081, Installation of magnetic thermocouples on the reactor head, Rev. 0
-RWP 103-4083, Reactor head inspection (under head), Rev. 2
-Beaver Valley Power Station Radiological Access Request Form For Containment Entry
-Shipping paperwork package for shipment number B-2965 containing soiled anti-C clothing for shipment dated November 16, 2002
-CR 03-00244, High dose rate trash observed by vendor while laundering anti-Cs
-Isotopic analysis for a neutron-activated carabiner dated February 4, 2003
-Shipping worksheets for a neutron-activated carabiner including determinations for curie content, Department of Transportation (DOT) shipment subtype, reportable quantity, and A2 quantity, dated February 6, 2003

Procedures

-NOP-OP-2002, Shipment of radioactive material/waste, Rev. 1
-1/2-ADM-1630, Radiation worker practices, Rev. 5
-1/2-HPP-3.02.010, Primary-side steam generator maintenance/inspection, Rev. 0
-1/2-HPP-3.03.004, Handling radioactive material, Rev. 3
-1/2-HPP-3.03.005, Removing material from an RCA, Rev. 2
-1/2-HPP-3.08.001, Radiological work permit, Rev. 0

Section 2OS2: ALARA Planning and Controls

Documents

-Pre-job ALARA review 03-1-05, I&C-Routine maintenance
-Pre-job ALARA review 03-1-11, ISI
-Pre-job ALARA review 03-1-14, Refuel operations/disassembly-reassembly
-Pre-job ALARA review 03-1-20, Steam generator secondary side sludge lancing/video inspection
-Pre-job ALARA review 03-1-22, Steam generator platform support
-Ongoing ALARA review 03-1-22, Steam generator platform support, March 14, 2003
-Ongoing ALARA review 03-1-23, Steam generator channel head work, March 17, 2003
-Pre-job ALARA review 03-1-28, Valve repair on elevation 718 of the reactor containment building
-Pre-job ALARA review 03-1-39, Reactor coolant pump (1 RC-P-1B) seal inspection/repair
-Pre-job ALARA review 03-1-36, CRDM nozzle and reactor head inspection
-Pre-job ALARA review 03-1-47, Containment scaffolding/erect and remove
-Pre-job ALARA review 03-1-41, Steam generator secondary side foreign object removal
-Pre-job ALARA review 03-1-44, Steam generator replacement project
-Pre-job ALARA review 03-1-52, Installation of magnetic thermocouples on the reactor head
-Pre-job ALARA review 03-1-42, Reactor head inspection (under head)

Procedures

-1/2-ADM-1621, ALARA program, Rev. 0
-1/2-HPP-3.08.001, Radiological work permit, Rev. 0
-1/2-HPP-3.08.005, ALARA review program, Rev. 0

Section 2OS3: Radiation Monitoring Instrumentation and Protective Equipment

Documents

Purchase order requirements dated January 3, 2002, for certification as an airmask service center and for a current DOT tester identification number
Respiratory protection lesson plan RP0220(LP-RP-09) titled, “MSA-401 SCBA Operation and Use,” Rev. 6
Qualification matrices for Operations Group, Maintenance Groups (Mechanical, Electrical, and

Instrumentation and Controls), and Radiation Protection Group

Procedures

1/2-ADM-1335, “Radiological Protection Technician Training,” Rev. 0
1/2-ADM-1337, “Industrial Safety Training Programs,” Rev. 0
1/2-OM-48.4.A, “Qualification and Certification of Operations Personnel,” Issue 4, Rev. 1

Section 4OA2: Performance Indicator Verification

NRC EPP Performance Indicator Indications, 1/2-ADM-111, Rev. 0

LIST OF ACRONYMS

1R15	Unit 1 Refueling Outage 15
ADAMS	NRC Document System
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
BCO	Basis for Continued Operation
BVPS	Beaver Valley Power Station
BVT	Beaver Valley Test
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CT	Current Transformer
ECT	Eddy Current Test
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
ERO	Emergency Response Organization
ERT	Event Review Team
FAQ	Frequently Asked Question
FENOC	FirstEnergy Nuclear Operating Company
gpm	Gallons per Minute
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
kV	Kilovolt
LCO	Limiting Condition of Operation
LOIA	Loss of Instrument Air
LOOP	Loss of Offsite Power
MFW	Main Feedwater
mR/hr	Millirems per Hour
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NUREG	NRC Technical Report Designation
OM	Operating Manual
OPDT	Overpower Delta Temperature
OST	Operational Surveillance Test
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post-Maintenance Test
PORV	Power Operated Relief Valve
PRT	Pressurizer Relief Tank
QS	Quench Spray

RCA	Radiologically-Controlled Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REJ	Rubber Expansion Joint
RO	Reactor Operator
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SDP	Significant Determination Process
SG	Steam Generator
SI	Safety Injection
SLCRS	Supplementary Leak Collection and Release System
SSC	Structures, Systems, and Components
SW	Service Water
Tave	Average Coolant Temperature
TI	Temporary Instruction
TPCS	Transient without Power Conversion System
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Test
Vac	Volt Alternating Current
VT	Visual Test
WO	Work Order

TEMPORARY INSTRUCTION

TI 2515/150 Rev. 1 - Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles Reporting Requirements

a.1. Was the examination performed by qualified and knowledgeable personnel?

The visual test (VT) of the outside surface of the head and areas around the control rod drive mechanisms (CRDMs) was performed by qualified and knowledgeable personnel using effective video imaging and optical equipment.

The examination was performed by qualified and knowledgeable personnel with certification to the American Society of Mechanical Engineers (ASME), Section XI, Level II and Level III for visual examiners. In addition, Level II and Level III examiners had received training in this type of inspection. The training included a review of industry experiences, lessons learned, inspection results and procedure requirements.

The eddy current tests (ECT) and ultrasonic tests (UT) were performed by qualified and knowledgeable personnel using equipment and procedures that were demonstrated to be capable of identifying CRDM degradation.

a.2. Was the examination performed in accordance with approved procedures?

The VT, ECT and UT were in accordance with approved and adequate procedures.

a.3. Was the examination able to identify, disposition, and resolve deficiencies?

The examination was adequate to identify, disposition and resolve deficiencies. A detailed systematic visual examination by quadrants was made of each penetration. The VT examination documentation included a written record and video. The ECT and UT documentation included computer-based data storage for re-review during future examinations.

a.4. Was the examination capable of identifying the PWSCC phenomenon described in the bulletin?

The examination performed was capable of identifying the PWSCC phenomenon described in the Bulletin. The examination was adequate to identify, disposition and resolve deficiencies. The VT, ECT and UT examinations were complimentary to each other in providing a full outside head surface and CRDM/weld volumetric examination.

b. What was the condition of the reactor vessel head?

The head had an interim visual inspection and a top surface cleaning in November 2002 and was returned to power for approximately three months before the Spring 2003 refuel outage. Examination of the head under the insulation in the refuel outage showed no boric acid present except for a minor amount directly traceable to leakage from a seal area above the head on two CRDMs. The general condition of the head was mostly clean bare metal with some paint and minor debris remaining. The video taped inspection showed no boron deposits that were considered to result from leakage through the CRDM to head welds or the CRDMs.

c. Could small boron deposits, as described in the Bulletin 01-01, be identified and characterized?

Small boron deposits, as described in Bulletin 2001-01, could have been identified and characterized by the visual examination technique used. None were found during the visual inspection.

d. What material deficiencies were identified that required repair?

Of the four CRDMS from heat number 3935, eddy current examination showed that two had slightly skewed axial cracking on the outer surface (OD) below the groove weld with depths of 0.2 inch. The other two CRDMs of this heat number had some shallow cracking on the OD. Some of the cracks intersected with the groove welds but did not extend into the welds. These four CRDMs were scheduled for weld cladding over the groove weld and the full CRDM OD surface.

e. What, if any, significant items could impede effective examination?

The thermal sleeves that are inside most of the CRDMs and CRDM weld distortion result in a narrow gap between the sleeve OD and the CRDM inner diameter (ID) that prevents UT examination of some CRDMs and makes ECT examination difficult on these and others. The UT tool requires a wider gap than the ECT tool.

During the ECT data review the initial vertical extent of coverage by ECT on the CRDM OD was determined to be incomplete in that the lower inch was not examined. Corrective action included ECT examination of these areas with the exception of the area within 10mm of the tube end. Reference CR 003-04203 for details.

f. The basis for the temperature used in the susceptibility ranking calculation.

The basis for the temperature of the RPV head used in the susceptibility ranking calculation was from the thermohydraulic code used in a previous baffle former bolt analysis calculation. The use of the head temperature from this analysis placed the BV Unit 1 head in the high susceptibility sub-population with an effective degradation years' value of 14 years. A modification during the 2003 refuel outage was to install thermocouples on the Unit 1 head to measure the actual head temperature.