April 24, 2002

Mr. L. W. Myers
Senior Vice President
FirstEnergy Nuclear Operating Company
Post Office Box 4
Shippingport, Pennsylvania 15077

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

Dear Mr. Myers:

On March 30, 2002, the NRC completed an inspection at your Beaver Valley Units 1 & 2. The enclosed report documents the inspection findings that were discussed with you and members of your staff on April 8, 2002.

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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified one issue of very low safety significance (Green).

Immediately following the terrorist attacks on the World Trade Center and the Pentagon, the NRC issued an advisory recommending that nuclear power plant licensees go to the highest level of security, and all promptly did so. With continued uncertainty about the possibility of additional terrorist activities, the Nation's nuclear power plants remain at the highest level of security and the NRC continues to monitor the situation. This advisory was followed by additional advisories, and although the specific actions are not releasable to the public, they generally include increased patrols, augmented security forces and capabilities, additional security posts, heightened coordination with law enforcement and military authorities, and more limited access of personnel and vehicles to the sites. The NRC has conducted various audits of your response to these advisories and your ability to respond to terrorist attacks with the capabilities of the current design basis threat (DBT). On February 25, 2002, the NRC issued an Order to all nuclear power plant licensees, requiring them to take certain additional interim compensatory measures to address the generalized high-level threat environment. With the issuance of the Order, we will evaluate FirstEnergy Nuclear Operating Company's compliance with these interim requirements.

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 (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

We appreciate your cooperation. Please contact me at (610) 337-5146 if you have any questions regarding this letter.

Sincerely,

/RA/

John F. Rogge, Chief
Projects Branch 7
Division of Reactor Projects

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

Enclosure: Inspection Report 50-334/02-02; 50-412/02-02
Attachments: 1) NRC Temporary Instruction 2515/145 - Circumferential Cracking of RPV Head Penetration Nozzles Reporting Requirements
2) Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-334, 50-412
License Nos.	DPR-66, NPF-73
Report Nos.	50-334/02-02, 50-412/02-02
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	February 10 - March 30, 2002
Inspectors:	Dave Kern, Senior Resident Inspector Greg Smith, Resident Inspector Neil Perry, Senior Project Engineer John Caruso, Senior Operator Licensing Examiner Steve Dennis, Resident Inspector Joe Furia, Senior Health Physicist Edwin Gray, Senior Reactor Inspector Al Lohmeier, Reactor Inspector Len Prividy, Senior Reactor Inspector Craig Smith, Resident Inspector
Approved by:	John Rogge, Chief Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000334-02-02, IR 05000412-02-02, on 02/10-03/30/2002; FirstEnergy Nuclear Operating Company; Beaver Valley Power Station; Units 1 & 2. Event Follow-up.

The inspection was conducted by resident inspectors, a regional operator licensing examiner, a regional senior health physicist, three regional reactor inspectors, and a regional projects inspector. The inspection identified one Green finding. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website http://www.nrc.gov/reactors/operating/oversight.html.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- **Green** The inspectors determined that human performance errors during preparation and posting of an equipment clearance on the 2-1EDG caused both Unit 2 EDGs to be inoperable for 4 days during refueling and reactor cavity draindown. Several human performance and process barriers broke down, leading to the 2-1 EDG inadvertently being made inoperable. Four separate people were involved with authorizing the wrong clearance tag, an operator posted the clearance tag without heeding caution postings for the safe shutdown train, and the 2-2 EDG clearance holder (job supervisor) walkdown failed to identify the error prior to beginning work. The inspectors also noted that this was the third equipment clearance error which increased plant risk during the last 6 months. Earlier examples included Unit 2 reactor vessel overfill during the refueling outage (9/01) and Unit 1 loss of instrument air reactor trip (12/01).

  The safety significance of this event was very low (Green) because alternate power supplies remained available and contingency procedures existed to reestablish containment and refill the reactor vessel upon a loss of power. Enforcement action remained under review pending issuance of the forthcoming licensee event report. (Section 4OA3.1)

B. Licensee Identified Violations

No violations were identified.

Report Details

SUMMARY OF PLANT STATUS

Unit 1 began this inspection period at 100 percent power. The ‘A’ main feedwater pump experienced elevated motor outboard bearing temperature throughout the period. On February 20, 2002, bearing temperature rapidly increased and operators promptly reduced power to 91 percent to stabilize motor bearing temperature. After stabilizing temperature, operators reestablished full power on February 21. On March 29, bearing temperature again rose rapidly. Operators reduced power to 92 percent to stabilize bearing temperature (Section 1R14). Afterwards, operators maintained 95 percent reactor power through the end of the inspection period.

Unit 2 began this inspection period with the reactor in Mode 6 (Refueling) for the Unit 2 ninth refueling outage (2R9). Core offload was in progress. The 2-1 emergency diesel generator (EDG) was inadvertently rendered inoperable for 4 days during the refueling outage (Section 4OA3.1). The unit was synchronized to the off-site electrical distribution grid at 6:51 p.m., on February 27, marking the end of the 23 day refueling outage. The reactor achieved 100 percent power on March 4. On March 15, operators performed a planned power reduction to approximately 40 percent to support repacking both feedwater heater drain tank pumps. Full power was restored on March 21. On March 29, another planned power reduction to 40 percent power was performed to repack the feedwater heater drain tank pumps due to continuing packing leakage problems.

1. REACTOR SAFETY (R)

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignments

.1 Unit 1 Quench Spray System Alignment Verification

a. Inspection Scope

The inspectors conducted a complete alignment verification of the Unit 1 quench spray system. This system is a risk important mitigating system for containment pressure control and emergency decay heat removal of the reactor coolant system (RCS). The inspectors reviewed operating manual (OM) figures associated with the system as well as the normal system alignment checklist (1OM-13.3.B.1, Rev. 7) to determine proper system alignment. In addition, the inspectors reviewed and evaluated the potential impact on the quench spray system operation from open work orders, design modifications, engineering memoranda, and corrective action (CA) program condition reports (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 1 and 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 work orders, design change packages (DCPs), engineering evaluations, and CA program condition reports.

- The inspectors verified the Unit 2 electrical power distribution system was properly aligned in accordance with TS 3.8.1.2, 3.8.2.2, and 3.8.2.4. The electrical distribution system was selected due to its high risk significance and one train being unavailable for planned maintenance.

- The inspectors verified the Unit 2 spent fuel pool cooling system was aligned properly as described in 2OM Figure 20-1, "Fuel Pool Cooling and Purification," Rev. 4. This system was selected because one of the two spent fuel pool cooling pumps (2FNC*P21A) was provided with an alternate and temporary power supply during an electrical bus outage (normal power supply was not available).

- The inspectors verified the Unit 2 supplementary leak collection and release system (SLCRS) was properly aligned in accordance with procedure 2OM-16.3.C, "SLCRS Power Supply and Control Switch List," Rev. 5, 2OM Figure 16-1, "SLCRS," Rev. 10, and 2OM Figure 16-2, "SLCRS," Rev. 6. Minor procedure deficiencies were documented in CRs 02-2681 and 02-2732.

- The inspectors verified the Unit 1 emergency alternating current (AC) power system was properly aligned in accordance with selected portions of procedures 10M-36.3.A.1 thru 10M-36.3.E., "4 kiloVolt (kV) Station Service System Normal System Alignment." Control room indications and controls were verified to be appropriate for the standby or operating status of the system and system CRs were reviewed to assure no degraded conditions existed to adversely affect operability.

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. 16 and the Unit 2 Fire Protection Safe Shutdown Report, Addendum 18, and identified the following risk significant areas:

- Unit 2 Primary Auxiliary Building 'C' Charging Pump Cubicle (Fire Area PA-3C)

- Unit 2 Primary Reactor Compartment - Residual Heat Removal Platform Hotwork (Fire Area RC-1)
- Unit 2 Primary Reactor Compartment - ‘C’ RCP Cubicle Hotwork (Fire Area RC-1)
- Unit 1 Turbine Building General Area (Fire Area TB-1)
- Unit 2 Cable Tunnel (Fire Area CT-1)

The inspectors reviewed the fire protection conditions of the above listed areas in accordance with the criteria delineated in Nuclear Power Division Administrative Procedure (NPDAP) 3.5, “Fire Protection,” Rev. 15. 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.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

a. Inspection Scope

Activities inspected during 2R9 were steam generator (SG) tube eddy-current testing (ECT) and repair, reactor pressure vessel (RPV) closure head penetration piping visual or surface testing (VT), ultrasonic testing (UT) of SG and pressurizer welds, and reactor vessel stud bolt examinations by UT, magnetic particle tests (MTs) and penetrant tests, tube sheet secondary side VT, radiographic testing (RT) of RCS charging pump system welds, and the CA program implementation for resolution of flow accelerated corrosion (FAC) pipe wall thinning. The objective of the inspection was to verify the effectiveness of the inservice inspection (ISI) program in monitoring RCS boundary degradation.

The inspectors assessed the effectiveness of the licensee’s ECT program, procedures, and inspection activities for monitoring degradation of SG tubes and determination of the causes thereof. This assessment was based on the rules and regulations of the SG examination program for Units 1 and 2, the Unit 2 SG examination guidelines, NRC Generic Letters, 10 Code of Federal Regulations (CFR) 50, Beaver Valley Power Station (BVPS) Unit 2 TSs, and the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section V and XI. Supporting the assessment, were parts of Nuclear Energy Institute (NEI) 97-06, Electric Power Research Institute (EPRI) pressurized water reactor SG examination guidelines, and the Westinghouse BVPS Unit 2 SG degradation assessment - 2R9.

To evaluate SG tube integrity, the inspectors reviewed the licensee’s commitments regarding SG repair criteria, (tube plugging & sleeving), the ECT and in-situ pressure testing program scope and procedures, foreign material exclusion controls, SG operating chemistry control, and the previous operating cycle performance (primary to secondary leakage). The 2R9 SG outage activities, including eddy current testing scope, were also compared to the appropriate EPRI and NRC guidelines.
The inspectors reviewed the licensee’s awareness of types of degradation experienced from past site and industry-wide operating experience to identify potential problem areas. The inspectors reviewed the choice of eddy current probe used by the licensee

for each SG area inspected, based on this operating experience. The inspectors observed licensee attention given to finding foreign materials during outage inspections through characteristics of inspection probe signals. The inspectors reviewed examples of primary/secondary water chemistry control that indicate critical elements are being monitored and kept within well established operating limits.

The inspectors reviewed the results of the 2R9 ECTs, noting characterization and locations of tube degradation in SGs ‘A,’ ‘B’ and ‘C,’ and comparing these with the results of the previous ECT inspection during 2R8. Based on these results, the inspectors reviewed the licensee’s estimation of the rate of degradation growth and the screening criteria used to determine whether the degraded tube should be plugged, subjected to in-situ pressure testing, or removed from the bundle. Furthermore, the inspectors reviewed the effect of this degradation on the structural integrity of the SG tubes and the resulting functional capability of the steam SGs to produce the required steam flow and quality after removing defective tubes from service. The inspectors confirmed that tube retention or plugging was performed in accordance with established repair criteria limits.

The inspectors observed discussions between the licensee and the Office of Nuclear Reactor Regulation (NRR) relating to the number of tubes inspected, location and extent of wall thickness penetration for each indication of an imperfection, and the identification of tubes plugged and/or repaired. Additionally, the licensee responded to questions asked by NRR related to the implementation and findings of SG ETC.

The licensee’s activities performed in response to NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” were inspected against the inspection requirements of NRC Temporary Instruction (TI), 2515/145, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles.” The description of the inspection scope and results is in section 4OA5 as specified by the TI.

Pressurizer (weld C-1) and SG pressure vessel (welds C2 & C3) shell weld UT procedure and inspection results were examined. The UT inspection method, acceptance criteria, and documentation for these tests were reviewed. The inspectors reviewed the nondestructive examination procedures for the UT, MT, and VT of the reactor vessel stud bolts.

The radiographs of charging pump system modification were reviewed. Pipe weld radiographs, including those for welds 2CHS-357-F-13-C, 977-F-17-C, F-1-C, F-6-C, F-7-C, were evaluated to determine whether the radiographs met ASME Code and radiographic procedural requirements and verify that acceptance criteria were appropriate.

Condition Report 02-01059, which documented a pipe wall thinning due to FAC and provided for CA, was reviewed. The mitigation strategy for identified FAC conditions was compared with EPRI and NRC guidelines.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

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 CAs. 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. For selected systems, the inspectors observed maintenance rule steering committee (MRSC) meetings to determine whether system performance was properly dispositioned for MR category (a)(1) or (a)(2) performance monitoring.

- The Unit 2 control rod drive mechanism (CRDM) cooling system health report and CRs documented multiple failures of cooling system fan motors. The inspectors interviewed system engineers and reviewed plans to improve system reliability. The system was designated as a MR category (a)(2) system.

- The Unit 1 main feedwater system health report and a CR documented a control valve failure that resulted in a reactor trip. The inspectors reviewed the MR (a)(1) evaluation for the control valve failure and interviewed system engineers concerning plans to improve feedwater control system reliability. The system was designated as a MR category (a)(2) system.

- The Unit 1 compressed air system health report and MR (a)(1) disposition review were evaluated for appropriateness of classification and planned improvements. Additionally, the inspectors discussed the status of system issues with the system engineer.

- The Unit 2 4kV distribution system health report and MR (a)(2) disposition review were evaluated for appropriateness of classification and planned improvements. The system had been designated as MR category (a)(1) in January 2000. Additionally, the general condition of the system was visually inspected, and the inspector discussed the status of system issues with the system engineer.

- The Unit 1 turbine-driven auxiliary feedwater (AFW) pump was overhauled in October 2001. The activities included a seal modification and steam supply trip valve corrective maintenance. An oil leak and thrust bearing damage occurred during the post-maintenance test due to deficient work activities at a vendor facility. This AFW train was unavailable for about 68 hours for the work activities. This system was designated as a MR category (a)(2) system. The inspectors reviewed the MR unavailability goals as described in the licensee's MR program, and determined that no performance goals were exceeded.
- Enertec Model DRV-Z nozzle check valves were designated as MR category (a)(1) in July 1999, due to failure of the stainless steel seat ring. These valves were used in several systems including AFW and main steam. Valve performance improved in 2000 and 2001. However, the MRSC determined that the system should remain in category (a)(1), pending causal assessment of leakage test failure of main steam check valve, 1MS-20 (CR 01-5537).

- Unit 2 heater drain system was a MR category (a)(1) system due to plant downpowers to repack the heater drain pumps in early 2001. The system subsequently achieved the stated goal of not requiring further pump repacking to address leakage prior to achieving full power operation following the February 2002 refueling outage. However, the pumps developed excessive packing leakage in March 2002, shortly after the plant achieved full power. The MRSC determined the system should remain in MR category (a)(1) until the root cause is fixed.

b. Findings

No findings of significance were identified.

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: 1) ½ Administrative Procedure (AM)1800, “Shutdown Safety,” Rev. 0; 2) Nuclear Power Division Administrative Procedure (NPDAP) 7.12, “Non-outage Planning, Scheduling, and Risk Assessment,” Rev. 11; 3) NPDAP 8.30, “Maintenance Rule Program,” Rev. 6; and 4) Conduct of Operations Procedure 1/2OM-48.1.I, “Technical Specification Compliance,” Rev. 9. The inspectors reviewed the routine planned maintenance, restoration actions, and emergent work for the following equipment removed from service:

- Planned refueling outage corrective maintenance on the Unit 2 main generator output breaker (PCB-362). The inspectors observed work activities and procedures to control switchyard maintenance activities and off-site power supply reliability. Switchyard maintenance activities create an increased risk for loss of off-site power events. The inspectors interviewed control room operators and reviewed the weekly maintenance risk summary to verify appropriate risk management actions were in place.

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 nonroutine plant evolutions, to determine whether personnel performance caused unnecessary plant risk or challenges to reactor safety. The inspectors evaluated whether the evolutions were properly implemented according to the applicable procedures.

- Unit 2 Operating Manual (OM) -50.4.L, “Reactor Coolant System Startup,” Rev. 0. This was the first time this integrated procedure had been used for performing RCS fill and vent, forming a pressurizer steam bubble, starting reactor coolant pumps (RCPs), and establishing normal operating conditions in various primary tanks.

- Repair, testing, and restoration of the Unit 2 main generator output breaker (PCB-352) required various switchyard power supply alignments and configuration controls to ensure the required number of off-site power supplies were maintained available as specified in TS and ½-AM-1800, “Shutdown Safety,” Rev. 1.

- On March 29, the Unit 1 ‘A’ main feedwater pump motor outboard bearing temperature rapidly increased. The rate of temperature change increased to 1 degree fahrenheit (°F) per minute, reaching 192°F at 3:58 p.m. The alarm setpoint was 160°F, procedural requirements are to reduce power at 200°F and secure the pump at 220°F. At 4:00 p.m., operators began reducing power using abnormal operating procedure 1.51.1, “Emergency Shutdown,” Rev. 9. Bearing temperature stabilized and operators then stabilized power at 92 percent. This was a repeat of a similar main feedwater pump bearing temperature excursion on February 20. Operators closely monitored bearing temperature and maximized main feedwater pump area cooling through the end of the inspection period. Contingency actions, such as manually tripping the reactor if the main feedwater pump failed from above 80 percent reactor power were properly briefed.

b. Findings

No findings of significance were identified.

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 limiting condition for operation was properly addressed.

- Unit 1 assessment of Westinghouse Nuclear Safety Advisory Letters (NSAL) 02-

3, “Steam Generator Mid-Deck Plate Pressure Loss Issue;” NSAL 02-4, “Maximum Reliable Indicated SG Water Level;” and NSAL 02-5, “SG Water Level Control System Uncertainty Issue.”

- Unit 2 assessment of Westinghouse NSAL 02-3, “Steam Generator Mid-Deck Plate Pressure Loss Issue;” NSAL 02-4, “Maximum Reliable Indicated Steam Generator Water Level;” and NSAL 02-5, “SG Water Level Control System Uncertainty Issue.”

- Unit 2 main steam isolation valve (2MSS-AOV101C) closure time failed to meet TS criteria of $\leq$ 5 seconds following implementation of Engineering Change Package (ECP) -141, ”Modify Closing Time of Main Steam Isolation Valves.” This was a repetitive problem. An engineering evaluation titled “2 Operational Surveillance Test (OST)-21.7 (Stroke Time Failure, 27-Feb-02),” documented the engineering basis for operability following interim CAs. Minor deficiencies in the operability assessment and CA implementation were documented in CRs 02-1869 and 02-1905.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed Unit 2 operator work-arounds (OWAs) to identify any effect on emergency operating procedure operator actions, and impact on possible initiating events and mitigating systems. The inspectors noted that two of eight OWAs were scheduled to be corrected and closed out during 2R9 (OWA 2-02-2-1 concerned the turbine bearing oil lift pumps and OWA 2-01-2-2 concerned operation of valve 2CHS-69 for gas makeup to the volume control tank. The inspectors verified that the actions and post-maintenance tests to eliminate these two OWAs were complete as specified in Work Orders 01-007917 and 00-030774. The inspectors also performed a walkdown of the Unit 2 control room annunciator systems per procedure 2OST-45.6, “Annunciator Systems Checkout,” Rev.13, to ensure that any degraded conditions were identified and dispositioned as required by the Operations Management Desktop Guide 002, “Operations Work-arounds/Control Room Deficiencies,” Rev. 5.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed and observed a post-maintenance test (PMT) 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 PMT was observed:

- 2 Beaver Valley Test (BVT) 1.39.04, "Station Battery [BAT*2-4] Service Test," Rev. 4, following replacement of station battery 2-4. The inspectors observed portions of the test and compared the test results against the procedure acceptance criteria and the requirements of Institute of Electrical and Electronic Engineers (IEEE) Standard 450-1980, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Acid Storage Batteries for Generating Stations and Substations." The inspectors reviewed CRs documenting station battery post-maintenance test problems and verified system engineers implemented appropriate CAs.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed selected 2R9 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, license conditions, and ½-AM-1800, "Shutdown Safety," Rev. 1. 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 RCS inventory due to the associated increase in shutdown risk. Specific activities evaluated included:

- 2OM-20.4.H "Draining the Refueling Cavity to the Refueling Water Storage Tank," Rev. 14
- 2OM-50.4.L "Reactor Coolant System Startup," Rev. 0
- 2OM-50.4.M "Station Startup - Mode 5 to Mode 3," Rev. 0
- 2OM-50.4.C "Instructions to Heatup Plant from Mode 4 to Mode 3," Rev. 41
- 2OM-50.4.D "Reactor Startup from Mode 3 to Mode 2," Rev. 38
- 2OM-52.4.A "Increasing Power from 5 percent Reactor Power and Turbine on Turning Gear to Full Load Operation," Rev. 46

- 2OM-51.4.L "Station Shutdown 40 percent to Mode 5," Rev 4. Observed plant shutdown to Mode 5 (cold shutdown) at the beginning of the outage. Also evaluated plant power reduction from 30 to 15 percent power after plant restart to accomplish PMT of turbine generator over speed trip and to accomplish electro-hydraulic control system leak repairs.
- 2RST-2.1 "Initial Approach to Criticality after Refueling," Rev. 5.
- Startup Readiness Review Assessment Meetings for Entry into Modes 4, 3, 2, and 1
- 2R9 Restart Mode Hold Condition Report List
- DCP 2403, "RCP Thermal Barrier Cooling Trip Valve Power Supply Modification"
- DCP 2435, "Charging Pump Automatic Recirculation Valve"

Additionally, the inspectors reviewed the station's commitments to NRC Generic Letter 88-17, "Loss of Decay Heat Removal," contained in the following procedures: 1) 2OST-6.11, "Prerequisites for Entering A Reduced RCS Inventory or Midloop Condition," Rev. 1; 2) 2OM-6.4.U, "Draining the RCS to Reduced Inventory or Midloop Condition," Rev. 8; and, 3) 2OM-6.4.V, "Reduced RCS Inventory Operation Checklist," Rev. 1. The inspectors observed the 2R9 RCS draindown and verified that the reduced RCS inventory level as defined in Generic Letter 88-17 was not reached.

The inspectors reviewed the 2R9 outage scope add/drop list to ensure that items dropped from the outage had an adequate basis for deferral or cancellation of the work. The inspectors reviewed the entire list, and selected those pertaining to safety-related and risk significant systems, for more in-depth review. This review included: why the work was originally scheduled for this outage; when work was last completed on the equipment; when it was rescheduled to occur; and the basis for the deferral or cancellation. Discussions were held with appropriate engineering personnel as necessary for additional information and clarifications.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and reviewed the following OSTs and BVTs concentrating on verification of the adequacy of the test to demonstrate the operability of the required system, as required by TS, or component safety function. Specific activities evaluated included:

- 20ST-24.4A "Steam Driven Auxiliary Feed Pump [2FWE*P22] Full Flow Test," Rev. 4. Inspector identified deficiencies associated with procedural requirements for 2MSS*SOV105D operability were documented in CR 02-2025.

- 2BVT 1.1.1 “Rod Drop Time Measurement and Rod Position Indication Verification,” Rev. 8

- 1OST-24.2 “Motor Driven Auxiliary Feed Pump Test (1FW-P-3A),” Rev. 21

b. Findings

No findings of significance were identified.

2. OCCUPATIONAL RADIATION SAFETY (OS)

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

The inspectors identified exposure significant work areas, high radiation areas, and airborne radioactivity areas in the plant, and reviewed associated controls and surveys of these areas to determine if the controls (i.e., surveys, postings, barricades) were appropriate. For these areas, the inspectors: 1) reviewed radiological job requirements and attended job briefings; 2) determined if radiological conditions in the work area were adequately communicated to workers through briefings and postings; 3) verified radiological controls, radiological job coverage and contamination control; and 4) verified the accuracy of surveys and applicable posting and barricade requirements. The inspectors: 1) determined if prescribed radiation work permits (RWPs), procedures, and engineering controls were in place; 2) whether licensee surveys and postings were complete and accurate; and 3) verified air samplers were properly located. Observation of work activities inside the radiologically controlled area occurred in the containment and auxiliary buildings. Technical Specification 6.12 and 10 CFR 20, Subpart G were used as the standard for necessary barriers. The inspectors reviewed electronic pocket dosimeter alarm setpoints (both integrated dose and dose rate) for conformity with survey indications and plant policy.

Direct observations of significant radiological activities were focused on the work being performed in support of 2R9. Jobs observed included: 1) reactor core offload/reload (RWP 202-5031); 2) CRDM inspections (RWP 202-5061); 3) SG platform support work (RWP 202-5040); 4) ISIs reactor building containment (RWP 202-5020); 5) replacement of 2RCS-P21C mechanical seals (RWP 202-5056); 6) repair/replace 2RHS-P21B (RWP 202-5043); and 7) overhaul fuel transfer system (RWP 202-5062).

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspectors reviewed work to be performed during the 2R9. Areas reviewed included a review of the use of low dose waiting areas, review of on-job supervision provided to workers, and a review of individual exposures from selected work groups. An evaluation of engineering controls utilized to achieve dose reductions, and analysis of licensee source term reduction plans was also conducted. The licensee's outage goals are not more than 26 days duration and not more than 97 person-rem (goal based on meeting 3-year rolling average top quartile performance). A review of actual outage work scope indicated that 117 person-rem of work activities were scheduled for completion during 2R9.

The inspectors observed radiation worker and radiation protection technician performance during high dose rate and/or high exposure jobs (i.e., work in the containment) and determined if workers demonstrated the as low as is reasonably achievable (ALARA) philosophy in practice. The inspectors also observed radiation worker performance to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

The inspectors reviewed ALARA job evaluations, exposure estimates, exposure mitigation requirements, and the results achieved for the work listed above. A review of the integration of ALARA requirements into work procedures and RWP documents, the accuracy of person-hour estimates and person-hour tracking, and generated shielding requests and their effectiveness to dose rate reduction was also conducted.

A review of actual exposure results versus initial exposure estimates for current work was conducted, including: 1) comparison of estimated and actual dose rates and person-hours expended; 2) determination of the accuracy of estimations to actual results; and 3) determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine compliance with the requirements contained in 10 CFR 20.1101(b).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors reviewed field instrumentation used by health physics technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers, portal monitors, and small article monitors. The inspectors conducted a review of instruments observed, specifically verification of proper function and certification of appropriate source checks for these instruments which are used to ensure that occupational exposures are maintained in accordance with 10 CFR 20.1201.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 performance indicators (PIs) for unplanned changes in reactor power of greater than 20 percent per 7000 hours of critical operation, to determine whether the NRC approved guidance, provided in NEI 99-02, "Regulatory Assessment Performance indicator Guideline," Rev. 1, was properly implemented. Manual and automatic scrams are excluded from this PI. The inspectors verified accuracy of the reported data through reviews of monthly operating reports, shift operating logs, Licensee Event Reports (LERs) and additional records. The inspectors reviewed 3 months of reported data (October - December 2001) and the latest 2 months of collected data which has not yet been reported (January - February 2002). No problems with PI accuracy or completeness were identified.

The inspectors also verified that NRC unresolved item 50-412/01-10-02, "Review of Licensee Report of Unplanned Power Changes per 7000 Critical Hours NRC Performance Indicator," had been properly resolved. The NRC/NEI working group determined that an April 2001 Unit 2 power change should have been reported. The licensee correctly updated their records and reported this with their January 2002 NRC PI report. The unresolved item is closed.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Selected Review of Condition Report Resolution Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of problems with river and service water system in-line strainers and an over-ranged auxiliary feedwater (AFW) system pump pressure indicator to determine whether they were of sufficient detail and scope to identify the likely problem causes, and address the potential extent of the condition. Additionally, the inspectors reviewed the licensee's corrective actions to determine if they addressed the identified causes, and were completed or scheduled commensurate with the significance of the problem.

b. Issues and Findings

The inspectors concluded the licensee's evaluations of these two issues were of appropriate detail to identify likely causes. However, in regard to the potential AFW over-pressurization condition, the inspectors concluded the licensee's evaluation did not address the condition of the associated relief valve and the periodic testing of similar relief valves. The inspectors concluded the licensee's corrective actions addressed the identified causes and were being implemented in a time frame commensurate with the safety significance of the problem. However, the inspectors determined that, while the Unit 1 river water strainer problems required operators to remove affected equipment from service, it was not identified as an operator-work around (OWA). Consequently, the design change to modify the Unit 1 strainers was not associated with an OWA to help ensure the priority of its completion.

River and Service Water in-Line Strainers

The inspectors reviewed CR 01-2082 which documented strainer fouling problems in Unit 1 River Water system lines to the charging pumps and control room air-conditioning units. The inspectors also reviewed CR 00-1307 and 01-0799 regarding fouling of Unit 2 service water in-line strainers in seal water supply lines to the service water pump mechanical seals. The Unit 1 strainer system design requires operators to remove equipment from service to clean the strainers, thereby increasing operator burden and equipment unavailability times.

The inspectors verified that the licensee's interim measures provided for increased strainer maintenance during seasonal periods of higher river debris loading. The licensee tracked corrective actions to implement design modifications to improve the reliability of the Unit 2 strainers and provide for redundant Unit 1 strainers. Regarding the Unit 1 strainers, the design change package is currently scheduled for approval in July 2002, which will support the next refueling outage schedule. Regarding the Unit 2 strainers, the responsible system engineer indicated an engineering work request would be initiated by May 2002 to develop the design change, and the design could be implemented with the plant operating.

The inspectors observed that the Unit 1 strainer system design required operators to remove the affected equipment from service for strainer maintenance. The inspectors concluded this example was comparable to OWA issues previously identified by the licensee. However, the licensee did not identify the problem as an OWA. Consequently, the corrective action to modify the Unit 1 strainers was not associated with an OWA to help ensure the priority of its completion. Following discussions with the inspectors, the Plant General Manager initiated action to add this issue to the OWA list.

Auxiliary Feedwater Pump Pressure Indicator

The licensee initiated CRs 01-4272 and 01-4678 in July 2001 to address an over-ranged pressure indicator gage on the suction side of the Unit 1 dedicated AFW pump. The inspectors reviewed the licensee's evaluation of the likely causes of the problem, potential consequences, the system over pressure protection design, and the corrective actions to address this problem. The inspectors concluded the licensee's evaluation and corrective actions adequately addressed the likely causes of the potential over-pressurization event and the condition of the piping.

However, the licensee's evaluation and corrective actions did not determine whether the associated non-safety relief valve (RV-1FW-130) functioned properly in July 2001, or is currently functioning. In response to inspector questions, the licensee determined this non-safety related relief valve was not periodically lift tested. Although the licensee tracked a corrective action to check the set pressure of the relief valve via a work order scheduled for June 2002, the inspectors concluded that the licensee's evaluation did not evaluate the condition of the relief valve, considering it was not periodically tested and the carbon steel piping line is relatively stagnant. Additionally, the evaluation did not address the adequacy of periodic testing for similar installed relief valves. The licensee initiated CR#02-2782 to address the relief valve condition and the extent of the problem.

.2 Resolution of Degraded Unit 2 Main Steam Isolation Valve Performance

The inspectors identified that CAs to resolve slow Unit 2 main steam isolation valve (MSIV) closure stroke time were ineffective. The design change which was implemented (engineering change package [ECP]-141), addressed symptoms of the problem, but the root cause had not been diagnosed or resolved. The test plan for ECP-141 did not establish criteria to evaluate the effectiveness of the modification. CAs including evaluation of preventive maintenance activities for the valve actuator had not been completed in time for implementation during the February 2002 refueling outage. The engineering evaluation for MSIV operability used incorrect test results, provided inaccurate assessment of operability margin, and did not address the root cause of the slow valve closure time. The inspectors reviewed test results, air actuator pressure, and interim corrective actions and determined that the Unit 2 MSIVs were currently operable. Condition Report 02-1905 was written to address the evaluation deficiencies listed above (Section 1R15).

4OA3 Event Follow-up

.1 Both Unit 2 Emergency Diesel Generators Inoperable During Refueling

a. Inspection Scope

On February 18, 2002, Unit 2 operators discovered that both EDGs were inoperable while the unit was in Mode 6 (refueling). The 2-2 EDG was out of service for planned maintenance. The 2-1 EDG had inadvertently been rendered inoperable 4 days earlier, due to an equipment clearance error. Prompt action, including an operational EDG test, was initiated to restore 2-1 EDG operability. The inspectors reviewed operators logs, work control documents, ongoing work activities, and conducted interviews to verify safe plant conditions. Following restoration of 2-1 EDG, retentioning of the reactor vessel head, and core flood-up after fuel load, 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 and that no additional NRC reactive response was necessary.
The inspectors reviewed the event in detail, including evaluation of RCS time to boiling (TTB), availability of alternate power supplies, and proceduralized actions to reestablish core cooling if off-site power had been lost. The inspectors also evaluated immediate CAs to determine whether adequate measures were implemented to preclude repetitive challenges to shutdown safety.

b. Findings

The inspectors determined that human performance errors during preparation and posting of an equipment clearance on the 2-1 EDG caused both Unit 2 EDGs to be inoperable for 4 days during refueling and reactor cavity draindown. The safety significance of this event was very low (Green) because alternate power supplies remained available and contingency procedures to refill the reactor vessel upon a loss of power were established.

At 11:17 a.m. on February 14, the 2-2 EDG was removed for service as operators began posting equipment clearance tags (clearance number 2R09-36-MNE-002) for planned maintenance. Reactor vessel core reload was in progress. At 1:58 p.m., an operator posted an equipment clearance tag on the potential transformer primary fuses for the 2-1 EDG, which made the 2-1 EDG inoperable. Both EDGs remained inoperable until February 18, at 6:30 p.m., when operators reinstalled the fuses on the 2-1 EDG. During this time period operators refueled the reactor core and drained the reactor cavity to the vessel flange level to support reactor vessel head reinstallation. The shortest TTB for the RCS during this period was approximately 70 minutes.

The licensee determined that several human performance and process barriers broke down, leading to the 2-1 EDG inadvertently being made inoperable. Clearance 2R09-36-MNE-002 incorrectly identified the wrong EDG's fuses to be pulled. Four separate people were involved with authorizing the wrong clearance tag (clearance preparer, reviewer, second reviewer, and approval). The operator who posted the clearance on the fuses failed to read and understand caution postings for the safe shutdown train and for the 2-1 EDG fuse cubicle. The 2-2 EDG clearance holder (job supervisor) walkdown failed to identify the error prior to beginning work. The inspectors also noted that this was the third in a series of equipment clearance errors that increased plant risk during the last 6 months. Earlier examples included Unit 2 reactor vessel overfill during the refueling outage (9/01) and Unit 1 loss of instrument air reactor trip (12/01).

The inadequate EDG clearance issue was more than minor because it had an actual impact on safety. The performance error made the 2-1 EDG inoperable for over 4 days which affected the safety of a shutdown reactor. The Phase 1 SDP directed the use of Inspection Manual Chapter 0609, Appendix G, Shutdown Operations SDP. The reactor was in refueling mode, with the RCS open and refueling cavity level less than 23 feet during part of this period. The power availability guideline to maintain three sources of AC power including: one offsite and one onsite source was not met. This condition degraded the capability to cope with a loss of offsite power and, therefore, required a Phase 2 SDP analysis. The inspectors assessed the reactor core TTB, availability of accident mitigation equipment, contingency procedures for reactor vessel refill and to reestablish containment integrity without AC power, and human performance success likelihood for this event. The inspectors reviewed this information with the NRC Region I Senior Risk Analyst who performed a Phase 2 risk assessment. Primarily due to the quality and content of contingency procedures, and the design availability of an emergency AC cross-connect from Unit 1, the inspectors concluded that the event had very low safety significance and was a GREEN finding (CRs 02-1504, 02-1556). The licensee intends to report this event to the NRC as required by 10 CFR 50.73. Determination of appropriate enforcement actions will be performed during event follow-up review of the forthcoming licensee event report (LER).

.2 (Closed) LER 05000334/01-02: Manual Reactor Trip During Plant Shutdown

This event was discussed in NRC Inspection Report No. 50-334(412)01-10. No new issues were revealed by the LER. This LER was closed during an onsite review.

.3 (Closed) LER 05000412/01-02: Trip of One Service Water Pump Caused Automatic Actuation of Emergency Service Water Pump.

a. Inspection Scope

The inspectors reviewed the LER and related documentation to verify the event was accurately reported as required by 10 CFR 50.73, causal assessment and CAs were appropriate to preclude recurrence, and to determine whether the event was caused by a performance deficiency. The event was reported as a condition that resulted in the automatic actuation of an Emergency Service Water system that does not normally run and that serves as an ultimate heat sink. This LER was closed during an in-office review.

b. Findings

No findings of significance were identified.

4OA5 TI 2515/145 - Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles

a. Inspection Scope

The inspector reviewed the licensee's activities to detect circumferential cracking of RPV head penetration nozzles in response to NRC Bulletin 2001-01 as required by TI 2515/145. This included interviews with analyst personnel, reviews of qualification records and procedures, and observations of selected video tape records of the reactor vessel head visual examination. The inspector independently viewed a sample set of 29 out of the total 65 penetrations examined by the plant staff. In accordance with TI 2515/145, inspectors verified that deficiencies and discrepancies associated with the RCS structures and the examination process, if identified, would be placed in the licensee's CA process. The specific reporting requirements of TI 2515/145 are documented in Attachment B.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Lew Myers, and other members of licensee management following the conclusion of the inspection on April 8, 2002.

The licensee acknowledged the findings presented.

Some proprietary items were reviewed during the inspection but no proprietary information is presented in this report. The licensee did not indicate that any of the information presented at the exit meeting was proprietary.

ATTACHMENT 1

TI 2515/145 - Circumferential Cracking of RPV Head Penetration Nozzles Reporting Requirements

a.1. The examination was performed by qualified and knowledgeable personnel. Although the visual examination performed was to determine leakage, the inspectors found that the plant staff invoked the additional requirements of VT-1 examination for personnel, equipment and technique as described in the licensee's Bulletin 2001-01 response.

a.2. The visual examination was in accordance with approved and adequate procedures.

a.3. The examination was adequate to identify, disposition and resolve deficiencies.

a.4. The examination performed was capable of identifying the primary water stress corrosion cracking phenomenon described in the Bulletin.

b. The general condition of the reactor vessel head was mostly clean bare metal with some localized staining and minor debris. The step insulation configuration does not provide easy access for examination; however, the visual obstructions were overcome by the use of a video probe delivered through guide tubes and robotic crawlers. The video taped inspection showed no boron deposits that were considered to result from leakage through the CRDMs.

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

d. No material deficiencies associated with concerns in Bulletin 2001-01 were found.

e. The as low as reasonably achievable (ALARA) radiation exposure controls for the visual examination process were effective with a completed job dose of 2.7 person rem, which was close to the project estimate.

TI 2515/145 - Circumferential Cracking of RPV Head Penetration Nozzles Reporting Requirements (Lower Level Issues)

TI 2515/145, Section 04.04 c, requires that inspectors report lower-level issues concerning data collection and analysis, and issues deemed to be significant to the phenomenon described in Bulletin 2001-01. A lower-level issue identified by the inspector is reported below.

1. The inspectors noted that the examination procedure (54-ISI-367-02) did not clearly define the expected scope of verbal description, especially of the specific viewed positions, intended to be on the video tape. Clarification of the intended verbal description and scope on the video, and training to that method could enhance the value of the video tape as a stand alone record.

ATTACHMENT 2

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee:

R. Donnellon	Director, Maintenance
L. Freeland	Manager, Nuclear Regulatory Affairs & Corrective Actions
J. Lash	Director, Personnel Development
L. Myers	Senior Vice President, FENOC
L. W. Pearce	Plant General Manager
M. Pearson	Director, Nuclear Services
F. von Ahn	Director, Plant Engineering

ITEMS OPENED, CLOSED AND DISCUSSED

Closed

50-412/01-10-02	URI	Review of Licensee Report of Unplanned Power Changes per 7000 Critical Hours NRC Performance Indicator (Section 4OA1)
50-334/01-02	LER	Manual Reactor Trip During Plant Shutdown (Section 4OA3.2)
50-412/01-02	LER	Trip of One Service Water Pump Caused Automatic Actuation of Emergency Service Water Pump (Section 4OA3.3)
50-412, TI 2515/145		Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Steam Generator Eddy Current Testing
Mapping of Plugged SG Tubes in SGs ‘A,’ ‘B’ and ‘C’
Beaver Valley 2R9 SG ‘A,’ ‘B,’ and ‘C’ Eddy Current Inspection Summary 2/13/02
Beaver Valley 2R9 SG ‘A,’ ‘B,’ and ‘C’ Current Inspection Progress 2/13/02
Beaver Valley 2R8 SG ‘A,’ ‘B,’ and ‘C’ Examination Results Tubes with Indications
Beaver Valley 2R8 SG ‘A,’ ‘B,’ and ‘C’ Tubes Repaired by Plugging
Beaver Valley 2R9SG ‘A,’ ‘B,’ and ‘C’ Examination Results Tubes with Indications
Beaver Valley 2R9 SG ‘A,’ ‘B,’ and ‘C’ Tubes Repaired by Plugging
ISIE-ECP-2 R3 BVPS Unit 1 / 2 SG Examination Program
ISIE1-8 BVPS Unit 2 SG Examination Guidelines
SG-SGDA-02-2 BVPS 2R9 SG Degradation Assessment 1/2002

SG Eddy Current Inspection Summary, SGs A, B, &C 2/13/02
SG Tube Inspection Discussion Points BVPS Unit 2 Docket No. 50-412
ASME Boiler and Pressure Vessel Code Sections V and XI.
NRC Generic Letters 95-03 (Circumferential Cracking of SG Tubes, 95-05 (Voltage Based Criteria for Westinghouse SG Tubes Affected by Outside Diameter Stress Corrosion Cracking, 97-05 SG Tube Inspection Techniques, (97-06) Degradation of SG Internals

General Inservice Inspection
RT-600, General Requirements for Radiographic Examination
RT-604, Rev. 2, Radiographic Exam of piping circ. Butt welds governed by Section III 1992
Nondestructive (NDE) Procedure Number UT-306, Rev. 10. Manual UT of vessel welds greater than 2" thick
NDE Procedure Number UT-317, Rev. 3. Manual straight beam UT of bolting
NDE Procedure Number VT-500, Rev. 9. General requirements for visual examination
54-ISI-357-02, Procedure for the Visual Examination for Leakage of Reactor Head Penetrations
NDE 108.0 Task Lesson Plan Bare Head Inspection, dated 1/29/02
Inspection Plan 6010563A, Reactor Head Nozzle Penetration Remote Visual Inspection Plan for Beaver Valley Units 1 and 2, Revision 01, dated 1/16/02
Beaver Valley Power Station, Unit 1 & 2 Response to Bulletin 2001-01, Circumferential cracking of RPV head penetration nozzles
NDE Certification Records for Framatome personnel
Sample of the Video tapes of reactor vessel head exam which included 29 of 65 closure head penetrations
ES-M-009. FAC Program for BV Units 1 and 2, Rev. 5
NDE History of BVPS RPV Nozzle-to-Safe End Welds dated 10/20/00

Problem Identification and Resolution

8700-DMC-3038	Throttling Criteria for CH-E-7A, B, C
8700-DMC-2483	Tube Plugging Analysis
1CH-E-7A	Heat Exchanger Inspection Report
2507.650-719-031	Target Rock Corp. Project Technical Manual Solenoid Operated Valves
2OST-24.4	Steam Driven Auxiliary Feed Pump (2FWE*P22) Quarterly Test, Rev. 41
OMDG-002	Operations Work-Arounds/Control Room Deficiencies, Rev. 5

LIST OF ACRONYMS USED

2R9	Unit 2 Ninth Refueling Outage
AC	Alternating Current
AM	Administrative Procedure
AFW	Auxiliary Feedwater
ALARA	As Low As is Reasonably Achievable
ASME	American Society of Mechanical Engineers
BVPS	Beaver Valley Power Station
BVT	Beaver Valley Test
CA	Corrective Action
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DBT	Design Basis Threat
DCP	Design Change Package
ECCS	Emergency Core Cooling Systems
ECP	Engineering Change Package
ECT	Eddy-Current Testing
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ERT	Event Review Team
°F	Degree Fahrenheit
FAC	Flow Accelerated Corrosion
FENOC	First Emergency Nuclear Operating Company
IEEE	Institute of Electrical and Electronic Engineers
ISI	Inservice Inspection
kV	Kilovolt
LER	Licensee Event Report
MR	Maintenance Rule
MRSC	Maintenance Rule Steering Committee
MSIV	Main Steam Isolation Valve
MT	Magnetic Particle Test
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSAL	Nuclear Safety Advisory Letter
OM	Operating Manual
OST	Operational Surveillance Test
OWA	Operator Work-Around
PI	Performance Indicator
PMT	Post-Maintenance Test
PT	Penetrant Testing
RCA	Radiologically Controlled Area
RCP	Reactor Coolant Pump

RCS	Reactor Coolant System
RPV	Reactor Pressure Vessel
RT	Radiographic Testing
RV	Reactor Vessel
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
SLCRS	Supplementary Leak Collection and Release System
SSC	Structures, Systems, and Components
TI	Temporary Instruction
TS	Technical Specification
TTB	Time To Boiling
UT	Ultrasonic Testing
VT	Visual or Surface Testing